THIS FILING IS		
Item 1: ☐ An Initial (Original) Submission	OR ☒	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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** 2018/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 2018/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 Michelle Council	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) 382-3808	09 This Report Is (1) ☐ An Original (2) ☒ A Resubmission	10 Date of Report *(Mo, Da, Yr)* 05/29/2019

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 Dwight L. Jacobs	04 Date Signed *(Mo, Da, Yr)* 05/29/2019
02 Title SVP, CAO, Tax and Controller		

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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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".

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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	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) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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.

Electric in the states of North and South Carolina

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) ☒ No

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report *(Mo, Da, Yr)* 05/29/2019	Year/Period of Report End of 2018/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 2018 Duke Energy Corporation Form 10-K filed with the SEC in February, 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

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

0182399
0128811
0128813
0128810
0128812

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

0228315
0926000
0926999

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

142802
174015
176001
182321
232181
245001
245002

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

0411101
0282101
0190002
0282100
0190001
0411100

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

0407352
0456610
0407353

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

0411101
0282101
0190002
0282100
0190001
0411100

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	Executive Vice President, Administration and	Melissa Anderson	522,596
2	Chief Human Resources Officer		
3			
4	Senior Vice President, Chief Accounting Officer and	William E. Currens, Jr.	330,842
5	Controller (01/01/2018 - 05/31/2018)		
6			
7	Senior Vice President, Tax and Treasurer	Stephen Gerard De May	387,367
8	(01/01/2018 - 10/31/2018)		
9			
10	President, North Carolina	Stephen Gerard De May	406,735
11	(11/01/2018 - 12/31/2018)		
12			
13	Executive Vice President, Energy Solutions and	Douglas Esamann	625,950
14	President, Midwest & Florida Regions		
15			
16	President, North Carolina	David Fountain	388,626
17	(01/01/2018 - 10/31/2018)		
18			
19	Senior Vice President, Legal, Chief Ethics and	David Fountain	408,626
20	Comp Officer & Corp Secretary (11/01/2018 - 12/31/2018)		
21			
22	President, South Carolina	Kodwo Ghartey-Tagoe	341,505
23			
24	Chief Executive Officer	Lynn Good	1,350,000
25			
26	Senior Vice President, Chief Accounting Officer,	Dwight L. Jacobs	311,881
27	Tax and Controller (06/01/2018 - 12/31/2018)		
28			
29	Executive Vice President & Chief Operating Officer	Dhiaa Jamil	807,188
30			
31	Executive Vice President, External Affairs, and	Julia Janson	640,625
32	Chief Legal Officer		
33			
34	Senior Vice President, Corporate Development and	Karl Newlin	484,100
35	Treasurer (11/1/2018 - 12/31/2018)		
36			
37	Executive Vice President, Customer and Delivery	Lloyd Yates	703,921
38	Operations and President, Carolinas Region		
39			
40	Executive Vice President and President,	Franklin Yoho	514,500
41	Natural Gas Business		
42			
43	Executive Vice President & Chief Financial Officer	Steven Keith Young	710,325
44			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 M. Jamil	550 South Tryon Street, Charlotte, NC 28202
5	Executive Vice President and Chief Operating Officer	
6		
7	Lloyd M. Yates	550 South Tryon Street, Charlotte, NC 28202
8	Executive Vice President, Customer and Delivery	
9	Operations and President, Carolinas Region	
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		
45		
46		
47		
48		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	ER17-1783
3	316	ER17-1783
4	317	ER17-1783
5	326	ER17-2437
6	327	ER17-2407
7	328	ER17-2407
8	329	ER17-2407
9	330	ER17-2407
10	331	ER17-2407
11	332	ER17-2407
12	333	ER17-2407
13	334	ER17-2407
14	335	ER17-1783
15	336	ER18-196
16	337	ER17-2407
17	338	ER17-2407
18	340	ER17-2106
19	Tariff Volume No. 4, Open Access Transmission	ER17-1357
20	Tariff, 9.0.0	
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)?	[ ] Yes [X] 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	20180515-5328	05/15/2018	ER11-3585	Informational Filing with	Tariff Volume No. 4, Open
2				2018 Annual Update for the	Access Transmission
3				OATT Formula Transmission	Tariff, 9.0.0
4				Rate of Duke Energy	
5				Carolinas, LLC	
6					
7	20180910-5165	09/10/2018	ER11-3585	Correction to May 15, 2017	Filing with 2017 Annual Update
8				Informational Formula	for the OATT
9				Transmission Rate of	
10				Duke Energy Carolinas, LLC	
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					
45					
46					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
5	219	Accumulated Provision for Depreciation of	b	25,26
6		Electric Utility Plant (Account 108)		
7	219	Accumulated Provision for Depreciation of	c	24,25
8		Electric Utility Plant (Account 108)		
9	234	Accumulated Deferred Income Taxes-Other Property	c	18
10	263	Taxes Accrued, Prepaid and Charged during year	i	5,10,17,23,27,30,31,32
11	263	Taxes Accrued, Prepaid and Charged during year	i	5
12	275	Accumulated Deferred Income Taxes-Other Property	k	9
13	276	Accumulated Deferred Income Taxes-Other Property	k	19
14	311	Sales for Resale	k	Subtotal Non-RQ
15	320	Electric Operation and Maintenance Expense	b	5,12
16	321	Electric Operation and Maintenance Expense	b	90,91,112
17	321	Electric Operation and Maintenance Expense	b	80
18	323	Electric Operation and Maintenance Expense	b	197,189,191
19	323	Electric Operation and Maintenance Expense	b	192,197
20	336	Depreciation and Amortization of Electric Plant	f	1,7,10
21	336	Depreciation and Amortization of Electric Plant	f	1,6,7,10
22	354	Distribution of Salaries and Wages	b	20,24,65
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.

None

2. None

3. None

4. None

5. None

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

7. None

8. The fourth quarter does not have any scale wage changes for DE Carolinas.

   The third quarter compensation cycle had an approximate 3% merit increase and resulted in an annualized impact to the business of $6,764,996 covering 2,830 Duke Energy Carolinas’ employees.

   The first quarter compensation cycle had an approximate 3% merit increase and resulted in an annualized impact to the business of $17,044,310 covering 5,861 Duke Energy Carolinas' employees.

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 2018.

The changes in officer and directors for Duke Energy Carolinas, LLC. that occurred during the fourth quarter of 2018 are as follows:

Resignations effective 12/31/18

Caren B. Anders	Vice President, Operations Support
Christopher B. Heck	Vice President and Chief Information Officer
John F. Smith, III	Senior Vice President, Distribution Grid Performance and Contractor Operations

Resignations effective 11/1/18

Swati V. Daji	Senior Vice President, Chief Procurement Officer
Joni Y. Davis	Vice President, Marketing and Customer Engagement
Stephen Gerard De May	Treasurer and Senior Vice President, Tax
David B. Fountain	President, North Carolina
Emily G. Henson	Vice President, Distribution Construction and Maintenance - Carolinas West
Rufus Stanley Jackson	Vice President, Distribution Construction and Maintenance - Carolinas East
Julia S. Janson	Executive Vice President, External Affairs, Chief Legal Officer and Secretary
Karl W. Newlin	Senior Vice President, Corporate Development

L. Stanford Sherrill, Jr.	Vice President, Workforce Development, Diversity & Inclusion
Alexander J. Weintraub	Senior Vice President, Customers Solutions
Sandra S. Wyckoff	Vice President and Chief Ethics and Compliance Officer

Resignations effective 10/1/18

Scott L. Batson	Senior Vice President, Nuclear Operations (SC)
Steven D. Capps	Senior Vice President, Nuclear Corporate
Kim Maza	Vice President, Nuclear Corporate Governance & Oversight

Appointments effective 11/16/18

Melody Birmingham-Byrd	Senior Vice President and Chief Procurement Officer

Appointments effective 11/1/18

Donald E. Broadhurst	Vice President Operations - Customer Delivery
Swati V. Daji	Senior Vice President, Customer Solutions
Joni Y. Davis	Vice President, Chief Diversity and Inclusion Officer
Stephen Gerard De May	President, North Carolina
David B. Fountain	Senior Vice President,Legal, Chief Ethics and Compliance Officer and Secretary
Emily G. Henson	Vice President Operations - Customer Delivery
Rufus Stanley Jackson	Vice President Operations - Customer Delivery
Julia S. Janson	Executive Vice President, External Affairs and Chief Legal Officer
Jackie Joyner	Vice President Operations - Customer Delivery
Karl W. Newlin	Senior Vice President, Corporate Development and Treasurer
L. Stanford Sherrill, Jr.	Vice President, Talent Acquisition and Workforce Development
Sandra S. Wyckoff	Vice President, Ethics and Compliance

Appointments effective 10/16/18

Mia S. Haynes	Vice President, Customer Care

Appointments effective 10/1/18

Scott L. Batson	Regional Senior Vice President, Customer Delivery Carolinas
Steven D. Capps	Senior Vice President, Nuclear Operations (SC)
Larry E. Hatcher	Senior Vice President, Customer Delivery Governance, Program and Support
Kim Maza	Vice President, Nuclear Corporate Operations

The changes in officer and directors for Duke Energy Carolinas, LLC. that occurred during the remainder of 2018(Q1-3)are as follows:

Resignations effective 9/14/18

Lisa M. Marcuz	Vice President, Talent Management

Resignations effective 8/31/18

David J. Maxon	Senior Vice President, Distribution Construction and Maintenance

Resignations effective 8/1/18

Rodney E. Gaddy	Vice President, Administrative Services

Resignations effective 7/16/18

Larry E. Hatcher	Vice President, Natural Gas Operations Excellence
Brian R. Weisker	Vice President, Coal Combustion Products Operations and Maintenance

Appointments effective 9/3/18

Dennis P. Gilbert, Jr.	Vice President and Chief Information Security Officer

Appointments effective 8/1/18

Rodney E. Gaddy	Senior Vice President, Administrative Service

Appointments effective 7/16/18

Clark S. Gillespy	Senior Vice President, Economic Development
Brian R. Weisker	Vice President, Natural Gas Operational Excellence

The changes in officer and directors for Duke Energy Carolinas, LLC. that occurred during the second quarter of 2018 are as follows:

Resignations effective 6/30/18

Jeffrey A. Corbett	Senior Vice President, Distribution Engineering and Technical Customer Relations
Charles R. Whitlock	Senior Vice President, Strategic Growth Initiatives

Appointments effective 6/01/18

Donna T. Council	Vice President, HR Strategic Business Solutions
William E. Currens Jr.	Senior Vice President, Financial Planning and Analysis
James P. Henning	Senior Vice President, Customer Services
Dwight L. Jacobs	Senior Vice President, Chief Accounting Officer and Controller
Karl W. Newlin	Senior Vice President, Corporate Development
Deborah T. Patton	HR Director, Employee Relations
L. Stanford Sherrill, Jr.	Vice President, Workforce Development, Diversity and Inclusion
Harry K. Sideris	Senior Vice President and Chief Distribution Officer

Resignations effective 6/01/18

Donna T. Council	Vice President, Human Resources Business Partners
William E. Currens Jr.	Senior Vice President, Chief Accounting Officer and Controller
Michael A. Lewis	Senior Vice President and Chief Distribution Officer
L. Stanford Sherrill, Jr.	Vice President, Workforce Development, Employee and Labor Relations
Catherine S. Stempien	Senior Vice President, Corporate Development

Resignations effective 5/04/18

Michael R. Delowery	Vice President, Project Management and Construction

Resignations effective 4/30/18

Gayle S. Lanier	Senior Vice President, Customer Services

The changes in officer and directors for Duke Energy Carolinas, LLC. that occurred during the first quarter of 2018 are as follows:

Appointments effective 3/15/18

Larry E. Hatcher	Vice President, Natural Gas Operational Excellence

Appointments effective 3/01/18

Michael S. Hendershott	Assistant Treasurer

Appointments effective 2/01/18

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

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	41,161,863,023	38,269,626,033
3	Construction Work in Progress (107)	200-201	1,632,658,461	2,610,346,436
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		42,794,521,484	40,879,972,469
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	15,937,831,422	15,379,235,049
6	Net Utility Plant (Enter Total of line 4 less 5)		26,856,690,062	25,500,737,420
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	276,467,667	315,193,682
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		1	1
9	Nuclear Fuel Assemblies in Reactor (120.3)		1,152,233,077	1,158,802,565
10	Spent Nuclear Fuel (120.4)		475,269,001	652,248,802
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	1,089,674,019	1,283,591,983
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		814,295,727	842,653,067
14	Net Utility Plant (Enter Total of lines 6 and 13)		27,670,985,789	26,343,390,487
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)		119,145,876	118,030,854
19	(Less) Accum. Prov. for Depr. and Amort. (122)		41,247,904	38,522,984
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	13,114,081	13,114,070
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)		3,771,013,238	4,114,781,423
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)		207,518	94,297
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,862,327,179	4,207,592,030
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		32,258,744	15,882,026
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)		456,075,858	356,566,585
41	Other Accounts Receivable (143)		166,247,610	146,007,450
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		9,138,649	9,041,317
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		244,703,341	110,443,568
45	Fuel Stock (151)	227	220,760,888	229,301,332
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	682,226,291	697,542,126
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	103,378	71,125
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	46,163,658	38,694,923

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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	45,188,768	44,420,013
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)		23,491,197	15,298,464
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		236,004	299,733
61	Accrued Utility Revenues (173)		267,458,428	300,035,802
62	Miscellaneous Current and Accrued Assets (174)		12,410,350	24,594,139
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)		508,451	1,683,416
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		207,518	94,297
67	Total Current and Accrued Assets (Lines 34 through 66)		2,188,786,799	1,972,005,088
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		57,472,450	50,054,596
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	3,988,381,653	2,760,098,689
73	Prelim. Survey and Investigation Charges (Electric) (183)		9,500,938	14,113,390
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)		910,613	819,880
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	1,091,462,938	1,208,726,515
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)		57,438,955	63,880,032
82	Accumulated Deferred Income Taxes (190)	234	2,697,261,240	2,492,302,268
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		7,902,428,787	6,589,995,370
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		41,625,541,206	39,113,995,627

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	end of 2018/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	7,963,467,563	7,643,088,909
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)	-6,167,891	-7,080,444
16	Total Proprietary Capital (lines 2 through 15)		11,687,177,288	11,365,886,081
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	9,909,011,177	9,109,647,708
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	698,261,570	698,720,661
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		23,479,383	19,475,590
24	Total Long-Term Debt (lines 18 through 23)		10,883,793,364	10,088,892,779
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		103,966,297	56,762,634
27	Accumulated Provision for Property Insurance (228.1)		108,413,219	99,736,918
28	Accumulated Provision for Injuries and Damages (228.2)		633,919,490	491,016,994
29	Accumulated Provision for Pensions and Benefits (228.3)		94,896,447	89,513,551
30	Accumulated Miscellaneous Operating Provisions (228.4)		4,538,620	5,850,488
31	Accumulated Provision for Rate Refunds (229)		182,332,111	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		9,127,400	3,931,968
34	Asset Retirement Obligations (230)		3,948,779,041	3,609,220,322
35	Total Other Noncurrent Liabilities (lines 26 through 34)		5,085,972,625	4,356,032,875
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		973,427,628	817,851,599
39	Notes Payable to Associated Companies (233)		438,690,000	103,631,000
40	Accounts Payable to Associated Companies (234)		252,784,648	228,208,749
41	Customer Deposits (235)		126,584,652	120,757,841
42	Taxes Accrued (236)	262-263	170,427,273	238,979,854
43	Interest Accrued (237)		102,018,472	132,853,878
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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)		12,372,163	10,981,269
48	Miscellaneous Current and Accrued Liabilities (242)		372,526,662	297,226,618
49	Obligations Under Capital Leases-Current (243)		5,304,078	4,089,199
50	Derivative Instrument Liabilities (244)		9,410,350	24,594,139
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		21,253,078	8,707,368
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		9,127,400	3,931,968
54	Total Current and Accrued Liabilities (lines 37 through 53)		2,475,671,604	1,983,949,546
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	500,000
57	Accumulated Deferred Investment Tax Credits (255)	266-267	231,369,819	232,388,410
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	573,392,182	609,161,169
60	Other Regulatory Liabilities (254)	278	4,301,714,243	4,571,153,903
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)		4,343,192,939	4,129,591,930
64	Accum. Deferred Income Taxes-Other (283)		2,043,257,142	1,776,438,934
65	Total Deferred Credits (lines 56 through 64)		11,492,926,325	11,319,234,346
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		41,625,541,206	39,113,995,627

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	7,273,364,536	7,315,231,033		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,158,322,869	3,115,529,868		
5	Maintenance Expenses (402)	320-323	693,767,447	627,274,061		
6	Depreciation Expense (403)	336-337	1,029,546,198	984,369,327		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	65,860,546	52,750,296		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		149,999,980	115,028,712		
13	(Less) Regulatory Credits (407.4)		51,895,694	18,197,499		
14	Taxes Other Than Income Taxes (408.1)	262-263	291,829,421	277,321,324		
15	Income Taxes - Federal (409.1)	262-263	-3,506,659	212,429,582		
16	- Other (409.1)	262-263	7,058,710	19,575,054		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,425,900,089	1,418,857,415		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,088,738,036	1,031,927,861		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,258,630	-5,298,340		
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)		-250,563	-219,459		
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)		5,673,136,804	5,767,931,398		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,600,227,732	1,547,299,635		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
7,273,364,536	7,315,231,033					2
						3
3,158,322,869	3,115,529,868					4
693,767,447	627,274,061					5
1,029,546,198	984,369,327					6
						7
65,860,546	52,750,296					8
						9
						10
						11
149,999,980	115,028,712					12
51,895,694	18,197,499					13
291,829,421	277,321,324					14
-3,506,659	212,429,582					15
7,058,710	19,575,054					16
1,425,900,089	1,418,857,415					17
1,088,738,036	1,031,927,861					18
-5,258,630	-5,298,340					19
						20
						21
-250,563	-219,459					22
						23
						24
5,673,136,804	5,767,931,398					25
1,600,227,732	1,547,299,635					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)		1,600,227,732	1,547,299,635		
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)		110,300	25,596		
33	Revenues From Nonutility Operations (417)		21,115,902	21,881,794		
34	(Less) Expenses of Nonutility Operations (417.1)		19,614,542	19,495,926		
35	Nonoperating Rental Income (418)		-2,946,961	-2,964,090		
36	Equity in Earnings of Subsidiary Companies (418.1)	119		1,792,692		
37	Interest and Dividend Income (419)		927,820	1,550,841		
38	Allowance for Other Funds Used During Construction (419.1)		73,017,943	105,820,147		
39	Miscellaneous Nonoperating Income (421)		19,209,311	29,319,670		
40	Gain on Disposition of Property (421.1)			947,292		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		91,599,173	138,826,824		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		392,522	228,606		
44	Miscellaneous Amortization (425)		9,979	9,979		
45	Donations (426.1)		9,525,160	4,083,062		
46	Life Insurance (426.2)		-60,141			
47	Penalties (426.3)		1,830,590	3,870,703		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		4,083,343	3,470,140		
49	Other Deductions (426.5)		197,967,254	10,139,650		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		213,748,707	21,802,140		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	3,463,726	3,590,612		
53	Income Taxes-Federal (409.2)	262-263	-4,970,131	7,925,742		
54	Income Taxes-Other (409.2)	262-263	-463,781	929,426		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	19,094,320	32,806,720		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	47,570,994	5,431,647		
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)		-30,446,860	39,820,853		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-91,702,674	77,203,831		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		457,531,046	437,490,775		
63	Amort. of Debt Disc. and Expense (428)		6,364,114	5,981,227		
64	Amortization of Loss on Reaquired Debt (428.1)		6,441,077	6,494,805		
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)		16,249,126	6,738,727		
68	Other Interest Expense (431)		-13,246,775	-2,023,488		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		35,192,184	44,925,700		
70	Net Interest Charges (Total of lines 62 thru 69)		438,146,404	409,756,346		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,070,378,654	1,214,747,120		
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)		1,070,378,654	1,214,747,120		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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		7,527,852,813	6,952,264,769
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)		1,070,378,654	1,212,954,428
17	Appropriations of Retained Earnings (Acct. 436)			
18			-12,245,805	(12,366,386)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-12,245,805	(12,366,386)
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		-750,000,000	(625,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-750,000,000	(625,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		7,835,985,662	7,527,852,811
	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)		127,481,901	115,236,098
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		127,481,901	115,236,098
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		7,963,467,563	7,643,088,909
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		4,810,163	3,017,471
50	Equity in Earnings for Year (Credit) (Account 418.1)			1,792,692
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		4,810,163	4,810,163

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	1,070,378,654	1,214,747,120
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	1,029,546,198	984,369,327
5	Amortization of primary nuclear fuel	452,081,848	453,332,170
6	Provision for Rate Refunds	182,332,111	
7	Contributions to Qualified Pensions	-45,625,440	-8,851
8	Deferred Income Taxes (Net)	308,685,379	414,304,627
9	Investment Tax Credit Adjustment (Net)	-5,258,630	-5,298,340
10	Net (Increase) Decrease in Receivables	-215,223,976	80,260,298
11	Net (Increase) Decrease in Inventory	24,589,340	78,698,190
12	Net (Increase) Decrease in Allowances Inventory	-7,468,735	-2,173,158
13	Net Increase (Decrease) in Payables and Accrued Expenses	206,969,649	76,155,006
14	Net (Increase) Decrease in Other Regulatory Assets	-158,580,215	-86,321,652
15	Net Increase (Decrease) in Other Regulatory Liabilities	-2,815,746	-155,643,415
16	(Less) Allowance for Other Funds Used During Construction	73,017,943	105,820,147
17	(Less) Undistributed Earnings from Subsidiary Companies		1,792,692
18	Impairment Charges	191,963,296	
19	Payments for asset retirement obligations	-230,453,262	-270,723,877
20	Accrued Pension and other post-retirement benefit costs	3,688,980	-3,794,179
21	Other (provide details in footnote):	-231,410,211	-49,424,947
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	2,500,381,297	2,620,865,480
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-2,506,218,919	-2,342,415,996
27	Gross Additions to Nuclear Fuel	-266,581,709	-287,648,029
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-73,017,943	-105,820,147
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-2,699,782,685	-2,524,243,878
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		66,344,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-1,810,081,968	-2,124,155,924
45	Proceeds from Sales of Investment Securities (a)	1,810,081,968	2,127,855,924

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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	-125,186,605	-94,539,947
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)	-2,824,969,290	-2,548,739,825
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,994,522,000	574,197,000
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):	-33,814,359	-6,683,973
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,960,707,641	567,513,027
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-1,204,801,930	-115,987,598
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Net Increase (Decrease) in Intercompany Notes	335,059,000	103,631,000
78	Net Decrease in Short-Term Debt (c)		
79	Cash Dividend to Parent	-750,000,000	-625,000,000
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)	340,964,711	-69,843,571
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	16,376,718	2,282,084
87			
88	Cash and Cash Equivalents at Beginning of Period	16,182,026	13,899,942
89			
90	Cash and Cash Equivalents at End of period	32,558,744	16,182,026

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

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.: 67 Column: b

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	301,737,150

Supplemental disclosures:

Cash paid for interest, net of amount capitalized	452,336,331
Cash paid for income taxes, net	88,589,194

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

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)	32,558,744
Special deposits (132 - 134)	0
Temporary cash investments	0
Total	32,558,744

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.

- With the adoption of Accounting Standards Update (ASU) No. 2017-17, Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, on January 1, 2018, GAAP requires that the service cost related to pensions and post-retirement benefits other than pensions (PBOP) be reported with other compensation costs arising from services rendered by employees during the period be included in a subtotal of income from operations on the income statement, while non-service cost components are to be presented in the income statement separately outside a subtotal of income from operations. Only the service cost component may be eligible for capitalization if all other capitalization criteria are met. For FERC reporting purposes, costs related to pensions and PBOP will be included in the Net Utility Operating Income of the income statement. Duke has made a non-revocable election to capitalize only the service cost component of pension and PBOP costs, upon implementing ASU No. 2017-07. This change is not expected to have a material impact on the financial statements.

- Management has evaluated the impact of events occurring after December 31, 2018 up to February 28, 2019, the date that Duke Energy Corporation's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 12, 2019. These financial statements include all necessary adjustments and disclosures resulting from these evaluations including the following disclosure. On April 1, 2019, the NCDEQ issued a closure determination requiring Duke Energy Carolinas and Duke Energy Progress to excavate all remaining coal ash impoundments at facilities in North Carolina. Duke Energy estimates the cost to close these impoundments by excavation will be approximately $4 billion to $5 billion more than the current project cost estimate of $5.6 billion in the aggregate for the closure for all Duke Energy Carolinas and Duke Energy Progress impoundments. Excavation would likely extend beyond the required federal and state deadlines for impoundment closure. Duke Energy Carolinas and Duke Energy Progress intend to seek recovery of all costs through the ratemaking process consistent with previous proceedings. Duke Energy is still evaluating the closure determination from the NCDEQ and cannot predict the outcome of this matter.

DEC FERC Federal Tax Reform Disclosure

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-Generation/Production	Wholesale-Transmission	Total
EDIT Detail by Customer	$ (1,641)	$ (565)	$ (199)	$ (24)	$ (2,429)

In December 2018, Duke Energy Carolinas recorded adjustments to accumulated deferred income tax (ADIT) and EDIT after filing the 2017 tax return. As of December 2018, the cumulative re-measurement is shown below (in millions):

	254	190	282	283	410.2	182.3/253/254	236
EDIT	$ (2,466)	$ (992)	$ 2,488	$ 1,248	$ 15	$ (288)	$ (5)
Gross ups	$ (751)	$ 751					
Total	$ (3,217)	$ (241)	$ 2,488	$ 1,248	$ 15	$ (288)	$ (5)

	NC Retail	SC Retail	Wholesale-Generation/Production	Wholesale-Transmission	Total
EDIT Detail by Customer	$ (1,666)	$ (574)	$ (202)	$ (24)	$ (2,466)

The amount of excess deferred income taxes that is considered protected and unprotected as of December 31, 2018 and 2017 is reflected below (in millions):

EDIT Category	**12/31/18**	**12/31/17**
Protected:		
NC Retail	$ (914)	$ (912)
SC Retail	$ (315)	$ (314)
Production FERC	$ (111)	$ (111)
Transmission FERC	$ (13)	$ (13)
Unprotected:		
NC Retail	$ (752)	$ (729)
SC Retail	$ (259)	$ (251)
Production FERC	$ (91)	$ (88)
Transmission FERC	$ (11)	$ (11)
Total	**$ (2,466)**	**$ (2,429)**

On June 22, 2018 Duke Energy Carolinas received a regulatory order from the North Carolina Utilities Commission directing the company to maintain the excess deferred taxes in regulatory liability for the next 3 years or until their next general rate case proceeding, whichever is sooner. Duke Energy Carolinas has not received a regulatory order from the South Carolina Public Service Commission regarding how customer rates should be reduced for excess deferred income taxes. The reduction in the excess deferred income tax 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**
411.1	
Protected	In accordance with ARAM, which is generally between 25 and 50 years
Unprotected:	
NC Retail	Evaluating rate case for 2019
SC Retail	Rate case in process
Production FERC	10 years straight line – Starting 1/1/2019
Transmission FERC	Pending outcome of FERC NOPR

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, 2018 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 28, 2019. See "Index to the Combined Notes to Consolidated Financial Statements" for a listing of applicable notes for Duke Energy Carolinas, LLC. Management has evaluated the impact of events occurring after December 31, 2018 up to February 28, 2019, the date that Duke Energy Carolinas' U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 12, 2019. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

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**
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.

In October 2016, Duke Energy completed the acquisition of Piedmont. Duke Energy's consolidated financial statements include Piedmont's results of operations and cash flows activity subsequent to the acquisition date. Effective November 1, 2016, Piedmont's fiscal year-end was changed from October 31 to December 31, the year-end of Duke Energy. A transition report was filed on Form 10-Q (Form 10-QT) for the transition period from November 1, 2016, to December 31, 2016. See Note 2 for additional information regarding the acquisition.

In December 2016, Duke Energy completed an exit of the Latin American market to focus on its domestic regulated business, which was further bolstered by the acquisition of Piedmont. The sale of the International Energy business segment, excluding an equity method investment in NMC, was completed through two transactions including a sale of assets in Brazil to CTG and a sale of Duke Energy's remaining Latin American assets in Peru, Chile, Ecuador, Guatemala, El Salvador and Argentina to I Squared (collectively, the International Disposal Group). See Note 2 for additional information on the sale of International Energy.

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 17 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 8 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 percent of total Current Assets or Current Liabilities on the Duke Energy Registrants' Consolidated Balance Sheets at either December 31, 2018, or 2017.

		December 31,	
(in millions)	**Location**	**2018**	**2017**
Duke Energy			
Income taxes receivable	Current Assets	**$ 729**	$ 330
Accrued compensation	Current Liabilities	**793**	757
Duke Energy Carolinas			
Accrued compensation	Current Liabilities	**$ 251**	$ 252
Progress Energy			
Income taxes receivable	Current Assets	**$ 66**	$ 278
Customer deposits	Current Liabilities	**345**	338
Duke Energy Progress			
Customer deposits	Current Liabilities	**$ 137**	$ 129
Accrued compensation	Current Liabilities	**130**	132
Duke Energy Florida			
Customer deposits	Current Liabilities	**$ 208**	$ 208
Other accrued liabilities	Current Liabilities	**85**	16
Duke Energy Ohio			
Income taxes receivable	Current Assets	**$ 13**	$ 36
Customer deposits	Current Liabilities	**44**	46
Duke Energy Indiana			
Customer deposits	Current Liabilities	**$ 47**	$ 45
Piedmont			
Income taxes receivable	Current Assets	**$ 11**	$ 43

Discontinued Operations

The results of operations of the International Disposal Group have been classified as Discontinued Operations on Duke Energy's Consolidated Statements of 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, 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. For the year ended December 31, 2016, $18 million of net income is attributable to noncontrolling interests, which consisted of $7 million included in Income from Continuing Operations and $11 million included in Income (Loss) From Discontinued Operations, net of tax on Duke Energy's Consolidated Statement of Operations.

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 17 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, 2018			December 31, 2017		
	Duke Energy	**Progress Energy**	**Duke Energy Florida**	**Duke Energy**	**Progress Energy**	**Duke Energy Florida**
Current Assets						
Cash and cash equivalents	**$ 442**	**$ 67**	**$ 36**	$ 358	$ 40	$ 13
Other	**141**	**39**	**39**	138	40	40
Other Noncurrent Assets						
Other	**8**	**6**	**—**	9	7	—
Total cash, cash equivalents and restricted cash	**$ 591**	**$ 112**	**$ 75**	$ 505	$ 87	$ 53

Inventory

Inventory is used for operations and is recorded primarily using the average cost method. Inventory related to regulated operations is valued at historical cost. Inventory related to nonregulated operations is valued at the lower of cost or market. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to property, plant and equipment when installed. Inventory, including excess or obsolete inventory, is written-down to the lower of cost or market 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, 2018, and 2017. The components of inventory are presented in the tables below.

	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**

	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**
Materials and supplies	$ 2,293	$ 744	$ 1,118	$ 774	$ 343	$ 82	$ 309	$ 2
Coal	603	192	255	139	116	17	139	—
Natural gas, oil and other	354	35	219	104	115	34	2	64
Total inventory	$ 3,250	$ 971	$ 1,592	$ 1,017	$ 574	$ 133	$ 450	$ 66

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 15 for further information.

Goodwill and Intangible Assets

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 11 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 or, in the case of a business combination, on the fair value assigned in the allocation of the purchase price of the acquired business. 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 11 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,		
	2018	**2017**	**2016**
Duke Energy	**3.0%**	2.8%	2.8%
Duke Energy Carolinas	**2.8%**	2.8%	2.8%
Progress Energy	**2.9%**	2.6%	2.7%
Duke Energy Progress	**2.9%**	2.6%	2.6%
Duke Energy Florida	**3.0%**	2.8%	2.8%
Duke Energy Ohio	**2.8%**	2.8%	2.6%
Duke Energy Indiana	**3.3%**	3.0%	3.1%
Piedmont[(a)]	**2.5%**	2.3%	

(a) Piedmont's weighted average depreciation rate was 2.4 percent for the annualized two months ended December 31, 2016, and for the year ended October 31, 2016.

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). When it becomes probable an asset will be abandoned, the cost of the asset and accumulated depreciation is reclassified to Regulatory assets on the Consolidated Balance Sheets for amounts recoverable in rates. 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 10 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 23 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. Duke Energy Florida assumes Crystal River Unit 3 will be placed into a safe storage configuration until eventual dismantlement is completed by 2074. 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 9 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 18 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 14 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 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. 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.

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 22 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 20 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 7 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 21 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 23 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.

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. Otherwise, the taxes are accounted for net. 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)	**2018**	**2017**	**2016**
Duke Energy	**$ 405**	$ 376	$ 362
Duke Energy Carolinas	**35**	36	31
Progress Energy	**241**	220	213
Duke Energy Progress	**19**	19	18
Duke Energy Florida	**222**	201	195
Duke Energy Ohio	**105**	98	100
Duke Energy Indiana	**22**	20	17
Piedmont[(a)]	**2**	2	

(a) Piedmont's excise taxes were immaterial for the two months ended December 31, 2016, and $2 million for the year ended October 31, 2016.

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, due to conditions established by regulators in conjunction with merger transaction approvals, 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. At December 31, 2018, and 2017, an insignificant amount of Duke Energy’s consolidated Retained earnings balance represents undistributed earnings of equity method investments.

New Accounting Standards

The new accounting standards adopted for 2018 and 2017 had no material impact on the presentation or results of operations, cash flows or financial position of the Duke Energy Registrants. The following accounting standards were adopted by the Duke Energy Registrants during 2018.

Revenue from Contracts with Customers. In May 2014, the FASB issued revised accounting guidance for revenue recognition from contracts with customers. The core principle of this guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration expected in exchange for those goods or services. The amendments also required disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The majority of Duke Energy’s revenue is in scope of the new guidance. Other revenue arrangements, such as alternative revenue programs and certain PPAs and lighting agreements accounted for as leases, are excluded from the scope of this guidance and, therefore, are accounted for and evaluated for separate presentation and disclosure under other relevant accounting guidance.

Duke Energy elected the modified retrospective method of adoption effective January 1, 2018. Under the modified retrospective method of adoption, prior year reported results are not restated. Adoption of this standard did not result in a material change in the timing or pattern of revenue recognition and a cumulative-effect adjustment was not recorded at January 1, 2018. Duke Energy utilized certain practical expedients including applying this guidance to open contracts at the date of adoption, expensing costs to obtain a contract where the amortization period of the asset would have been one year or less, ignoring the effects of a significant financing when the period between transfer of the good or service and payment is one year or less and recognizing revenues for certain contracts under the invoice practical expedient, which allows revenue recognition to be consistent with invoiced amounts (including unbilled estimates) provided certain criteria are met, including consideration of whether the invoiced amounts reasonably represent the value provided to customers.

In preparation for adoption, Duke Energy identified material revenue streams and reviewed representative contracts and tariffs, including those associated with certain long-term customer contracts such as wholesale contracts, PPAs and other customer arrangements. Duke Energy also monitored the activities of the power and utilities industry revenue recognition task force and has reviewed published positions on specific industry issues to evaluate the impact, if any, on Duke Energy’s specific contracts and conclusions. Duke Energy applied the available practical expedient to portfolios of tariffs and contracts with similar characteristics. The vast majority of sales, including energy provided to retail customers, are from tariff offerings that provide natural gas or electricity without a defined contractual term ("at-will"). In most circumstances, revenue from contracts with customers is equivalent to the electricity or natural gas supplied and billed in that period (including unbilled estimates). As such, adoption of the new rules did not result in a shift in the timing or pattern of revenue recognition for such sales. While there have been changes to the captions and descriptions of revenues in Duke Energy’s financial statements, the most significant impact as a result of adopting the standard are additional disclosures around the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. See Note 18 for further information.

Financial Instruments Classification and Measurement. On January 1, 2018, Duke Energy adopted FASB guidance, which revised the classification and measurement of certain financial instruments. The adopted guidance changes the presentation of realized and unrealized gains and losses in certain equity securities that were previously recorded in AOCI. These gains and losses are now recorded in net income. An entity's equity investments that are accounted for under the equity method of accounting are not included within the scope of the new guidance. This guidance had a minimal impact on the Duke Energy Registrant's Consolidated Statements of Operations and Comprehensive Income as changes in the fair value of most of the Duke Energy Registrants' equity securities are deferred as regulatory assets or liabilities pursuant to accounting guidance for regulated operations. The resulting adjustment of unrealized gains and losses in AOCI to retained earnings was immaterial. The primary impact to Duke Energy as a result of implementing this guidance is adding disclosure requirements to present separately the financial assets and financial liabilities by measurement category and form of financial asset. See Notes 15 and 16 for further information.

Statement of Cash Flows. In November 2016, the FASB issued revised accounting guidance to reduce diversity in practice for the presentation and classification of restricted cash on the Consolidated Statements of Cash Flows. Under the updated guidance, restricted cash and restricted cash equivalents are included within beginning-of-period and end-of-period cash and cash equivalents on the Consolidated Statements of Cash Flows. Duke Energy adopted this guidance on January 1, 2018. The guidance has been applied using a retrospective transition method to each period presented. The adoption by Duke Energy of the revised guidance resulted in a change to the amount of Cash, cash equivalents and restricted cash explained when reconciling the beginning-of-period and end-of-period total amounts shown on the Consolidated Statements of Cash Flows. In addition, a reconciliation has been provided of Cash, cash equivalents and restricted cash reported within the Consolidated Balance Sheets that sums to the total of the same such amounts in the Consolidated Statements of Cash Flows. Prior to adoption, the Duke Energy Registrants reflected changes in noncurrent restricted cash within Cash Flows from Investing Activities and changes in current restricted cash within Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows.

In August 2016, the FASB issued accounting guidance addressing diversity in practice for eight separate cash flow issues. The guidance requires entities to classify distributions received from equity method investees using either the cumulative earnings approach or the nature of the distribution approach. Duke Energy adopted this guidance on January 1, 2018, and elected the nature of distribution approach. This approach requires all distributions received to be categorized based on legal documentation describing the nature of the activities generating the distribution. Cash inflows resulting in a return on investment (surplus) will be reflected in Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows, whereas cash inflows resulting in a return of investment (capital) will be reflected in Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows. The guidance has been applied using the retrospective transition method to each period presented. There are no changes to the Consolidated Statements of Cash Flows for the periods presented as a result of this accounting change.

Retirement Benefits. In March 2017, the FASB issued revised accounting guidance for the presentation of net periodic costs related to benefit plans. Previous guidance required the aggregation of all the components of net periodic costs on the Consolidated Statements of Operations and did not require the disclosure of the location of net periodic costs on the Consolidated Statements of Operations. Under the amended guidance, the service cost component of net periodic costs is included within Operating Income within the same line as other compensation expenses. All other components of net periodic costs are outside of Operating Income. In addition, the updated guidance permits only the service cost component of net periodic costs to be capitalized to Inventory or Property, Plant and Equipment. This represents a change from previous guidance, which permitted all components of net periodic costs to be eligible for capitalization.

Duke Energy adopted this guidance on January 1, 2018. Under previous guidance, Duke Energy presented the total non-capitalized net periodic costs within Operation, maintenance and other on the Consolidated Statements of Operations. The adoption of this guidance resulted in a retrospective change to reclassify the presentation of the non-service cost (benefit) components of net periodic costs to Other income and expenses. Duke Energy utilized the practical expedient for retrospective presentation. The change in components of net periodic costs eligible for capitalization is applicable prospectively. Since Duke Energy's service cost component is greater than the total net periodic costs, the change results in increased capitalization of net periodic costs, higher Operation, maintenance and other and higher Other income and expenses. The resulting prospective impact to Duke Energy is an immaterial increase in Net Income. See Note 22 for further information.

For Duke Energy, the retrospective change resulted in higher Operation, maintenance and other and higher Other income and expenses, net, of $156 million and $139 million for the years ended December 31, 2017, and 2016, respectively. There was no change to Net Income for these prior periods.

The following new accounting standards have been issued, but have not yet been adopted by the Duke Energy Registrants, as of December 31, 2018.

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.

For Duke Energy, this guidance is effective for interim and annual periods beginning January 1, 2019. The 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, if applicable, is recorded to retained earnings at January 1, 2019. Upon adoption, agreements considered leases for the use of certain aircraft, space on communication towers, industrial equipment, fleet vehicles, fuel transportation (barges and railcars), land and office space will be recognized on the balance sheet. Duke Energy expects to adopt the following practical expedients:

Practical Expedient	Description	Election
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.	Duke Energy plans to elect this practical expedient.
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.	Duke Energy plans to elect this practical expedient for all asset classes.
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.	Duke Energy plans to elect this practical expedient for all asset classes.
Hindsight expedient (when determining lease term)	Elect to use hindsight to determine the lease term.	Duke Energy plans to elect this practical expedient.
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.	Duke Energy plans to elect this practical expedient.
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 ASC 842 to comparative periods, including disclosures.	Duke Energy plans to elect this practical expedient.
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 plans to elect this practical expedient for all asset classes.

Duke Energy currently expects to record right-of-use assets and operating lease liabilities on its balance sheet as shown in approximate amounts in the table below:

		(in millions)
Duke Energy	$	1,700
Duke Energy Carolinas		150
Progress Energy		850
Duke Energy Progress		400
Duke Energy Florida		450
Duke Energy Ohio		25
Duke Energy Indiana		60
Piedmont		30

In addition to the recognition of operating leases on the balance sheet, Duke Energy expects additional disclosures including both finance and operating lease costs, short-term lease costs, variable lease costs, weighted-average remaining lease term as well as weighted-average discount rates. Duke Energy does not expect a material change to its financial statements from adoption of the new standard for contracts where it is the lessor.

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 $5.0 billion and assumed Piedmont's existing long-term debt, which had a fair value of approximately $2.0 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, $103 million and $439 million for the years ended December 31, 2018, 2017 and 2016, 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.

Amounts recorded in 2016 include:

- Interest expense of $234 million related to the acquisition financing, including realized losses on forward-starting interest rate swaps of $190 million. See Note 14 for additional information on the swaps.
- Charges of $104 million related to commitments made in conjunction with the transaction, including charitable contributions and a one-time bill credit to Piedmont customers. $10 million was recorded as a reduction in Operating Revenues, with the remaining $94 million recorded within Operation, maintenance and other.
- Other transaction and integration costs of $101 million recorded to Operation, maintenance and other, including professional fees and severance charges.

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

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the combined results of operations of Duke Energy and Piedmont as if the merger had occurred as of January 1, 2015. The pro forma financial information does not include potential cost savings, intercompany revenues, Piedmont's earnings from a certain equity method investment sold immediately prior to the merger or non-recurring transaction and integration costs incurred by Duke Energy and Piedmont. The after-tax transaction and integration costs incurred by Duke Energy and Piedmont were $279 million for the year ended December 31, 2016.

This information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of Duke Energy.

(in millions)		Year Ended December 31, 2016
Operating Revenues	$	23,504
Net Income Attributable to Duke Energy Corporation		2,442

Piedmont's Earnings

Piedmont's revenues and net income included in Duke Energy's Consolidated Statements of Operations for the year ended December 31, 2016, were $367 million and $20 million, respectively. Piedmont's revenues and net income for the year ended December 31, 2016, include the impact of non-recurring transaction costs of $10 million and $46 million, respectively.

DISPOSITIONS

For the years ended December 31, 2018, and 2017, the Income (Loss) from Discontinued Operations, net of tax, was immaterial. The following table summarizes the Loss from Discontinued Operations, net of tax recorded on Duke Energy's Consolidated Statements of Operations for the year ended December 31, 2016:

(in millions)		Year Ended December 31, 2016
International Disposal Group	$	(534)
Other[(a)]		126
Loss from Discontinued Operations, net of tax	$	(408)

(a) Amount represents an income tax benefit resulting from immaterial out of period deferred tax liability adjustments for previously sold businesses not related to the International Disposal Group.

2016 Sale of International Energy

In February 2016, Duke Energy announced it had initiated a process to divest the International Disposal Group, and in October 2016, announced it had entered into two separate purchase and sale agreements to execute the divestiture. Both sales closed in December of 2016, resulting in available cash proceeds of $1.9 billion, excluding transaction costs. Proceeds were primarily used to reduce the Parent debt. Existing favorable tax attributes result in no immediate U.S. federal-level cash tax impacts. Details of each transaction are as follows:

- On December 20, 2016, Duke Energy closed on the sale of its ownership interests in businesses in Argentina, Chile, Ecuador, El Salvador, Guatemala and Peru to I Squared Capital. The assets sold included approximately 2,230 MW of hydroelectric and natural gas generation capacity, transmission infrastructure and natural gas processing facilities. I Squared Capital purchased the businesses for an enterprise value of $1.2 billion.
- On December 29, 2016, Duke Energy closed on the sale of its Brazilian business, which included approximately 2,090 MW of hydroelectric generation capacity, to CTG for an enterprise value of $1.2 billion. With the closing of the CTG deal, Duke Energy finalized its exit from the Latin American market.

Assets Held For Sale and Discontinued Operations

As a result of the transactions, the International Disposal Group was classified as held for sale and as discontinued operations in the fourth quarter of 2016. Interest expense directly associated with the International Disposal Group was allocated to discontinued operations. No interest from corporate level debt was allocated to discontinued operations.

The following table presents the results of the International Disposal Group for the year ended December 31, 2016, which are included in Loss from Discontinued Operations, net of tax in Duke Energy's Consolidated Statements of Operations.

		Year Ended December 31,
(in millions)		**2016**
Operating Revenues	$	988
Fuel used in electric generation and purchased power		227
Cost of natural gas		43
Operation, maintenance and other		341
Depreciation and amortization(a)		62
Property and other taxes		15
Impairment charges (b)		194
(Losses) Gains on Sales of Other Assets and Other, net		(3)
Other Income and Expenses, net		58
Interest Expense		82
Pretax loss on disposal(c)		(514)
Loss before income taxes(d)		(435)
Income tax expense(e)(f)		99
Loss from discontinued operations of the International Disposal Group	$	(534)

(a) Upon meeting the criteria for assets held for sale, beginning in the fourth quarter of 2016 depreciation expense ceased.

(b) In conjunction with the advancements of marketing efforts during 2016, Duke Energy performed recoverability tests of the long-lived asset groups of International Energy. As a result, Duke Energy determined the carrying value of certain assets in Central America was not fully recoverable and recorded a pretax impairment charge of $194 million. The charge represents the excess of carrying value over the estimated fair value of the assets, which was based on a Level 3 Fair Value measurement that was primarily determined from the income approach using discounted cash flows but also considered market information obtained in 2016.

(c) The pretax loss on disposal includes the recognition of cumulative foreign currency translation losses of $620 million as of the disposal date. See the Consolidated Statements of Changes in Equity for additional information.

(d) Pretax Loss attributable to Duke Energy Corporation was $(445) million for the year ended December 31, 2016.

(e) Amount includes $126 million of income tax expense on the disposal, which primarily reflects in-country taxes incurred as a result of the sale. The after-tax loss on disposal was $640 million.

(f) Amount includes an income tax benefit of $95 million. See Note 23, "Income Taxes," for additional information.

Duke Energy has elected not to separately disclose discontinued operations on the Consolidated Statements of Cash Flows. The following table summarizes Duke Energy's cash flows from discontinued operations related to the International Disposal Group.

		Year Ended December 31,
(in millions)		**2016**
Cash flows provided by (used in):		
Operating activities	$	204
Investing activities		(434)

Other Sale Related Matters

During 2017, Duke Energy provided certain transition services to CTG and I Squared Capital. Cash flows related to providing the transition services were not material as of December 31, 2017. All transition services related to the International Disposal Group ended in 2017. Additionally, Duke Energy will reimburse CTG and I Squared Capital for all tax obligations arising from the period preceding consummation on the transactions, and recorded a liability of $54 million and $78 million as of December 31, 2018, and 2017, respectively. Duke Energy has not recorded any other liabilities, contingent liabilities or indemnifications related to the International Disposal Group.

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 commercial 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.

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 12 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, 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)
Income 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 23 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 12 for additional information.

(d) Commercial Renewables includes an impairment charge of $91 million, net of $2 million Noncontrolling interests, related to goodwill. See Note 11 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 the retired Beckjord Generating Station described below. For additional information, see Note 2 for the Piedmont Merger and Note 20 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. See Note 4 for additional information.
(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 10 and 11 for additional information.
(d) Other includes $64 million of after-tax costs to achieve the Piedmont merger. See Note 2 for additional information.

	Year Ended December 31, 2016						
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Commercial Renewables**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Unaffiliated Revenues	$ 21,336	$ 875	$ 484	$ 22,695	$ 48	$ —	$ 22,743
Intersegment Revenues	30	26	—	56	69	(125)	—
Total Revenues	$ 21,366	$ 901	$ 484	$ 22,751	$ 117	$ (125)	$ 22,743
Interest Expense	$ 1,136	$ 46	$ 53	$ 1,235	$ 693	$ (12)	$ 1,916
Depreciation and amortization	2,897	115	130	3,142	152	—	3,294
Equity in earnings (losses) of unconsolidated affiliates(a)	5	19	(82)	(58)	43	—	(15)
Income tax expense (benefit)	1,672	90	(160)	1,602	(446)	—	1,156
Segment income (loss)(b)(c)	3,040	152	23	3,215	(645)	1	2,571
Add back noncontrolling interest component							7
Loss from discontinued operations, net of tax(d)							(408)
Net income							$ 2,170
Capital investments expenditures and acquisitions(e)	$ 6,649	$ 5,519	$ 857	$ 13,025	$ 190	$ —	$ 13,215
Segment assets	114,993	10,760	4,377	130,130	2,443	188	132,761

(a) Commercial Renewables includes a pretax impairment charge of $71 million. See Note 12 for additional information.
(b) Other includes $329 million of after-tax costs to achieve mergers. See Note 2 for additional information on costs related to the Piedmont merger.
(c) Other includes after-tax charges of $57 million related to cost savings initiatives. See Note 20 for further information.
(d) Includes a loss on sale of the International Disposal Group. Refer to Note 2 for further information.
(e) Other includes $26 million of capital investment expenditures related to the International Disposal Group. Gas Utilities and Infrastructure includes the Piedmont acquisition of $5 billion. See Note 2 for more information on the Piedmont acquisition.

Geographical Information

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

Major Customers

For the year ended December 31, 2018, revenues from one customer of Duke Energy Progress are $633 million. Duke Energy Progress has one reportable segment, Electric Utilities and Infrastructure. No other Subsidiary Registrant has an individual customer representing more than 10 percent 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
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
2016					
Electric Utilities and Infrastructure	$ 18,338	$ 2,095	$ —	$ 933	$ 21,366
Gas Utilities and Infrastructure	—	—	871	30	901
Commercial Renewables	—	303	—	181	484
Total Reportable Segments	$ 18,338	$ 2,398	$ 871	$ 1,144	$ 22,751

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, 2018				
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Total Reportable Segments**	**Other**	**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

	Year Ended December 31, 2016					
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Total revenues	$ 1,410	$ 503	$ 1,913	$ 31	$ —	$ 1,944
Interest expense	$ 58	$ 27	$ 85	$ 1	$ —	$ 86
Depreciation and amortization	151	80	231	2	—	233
Income tax expense (benefit)	55	44	99	(21)	—	78
Segment income (loss)	154	77	231	(39)	—	192
Income from discontinued operations, net of tax						36
Net income						$ 228
Capital expenditures	$ 322	$ 154	$ 476	$ —	$ —	$ 476
Segment assets	4,782	2,696	7,478	62	(12)	7,528

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)	2018	2017	2018	2017
Regulatory Assets				
AROs – coal ash	$ 4,255	$ 4,025	$ 2,061	$ 1,984
AROs – nuclear and other	772	852	601	655
Accrued pension and OPEB	2,654	2,249	1,074	906
Retired generation facilities	445	480	367	386
Debt fair value adjustment	1,099	1,197	—	—
Deferred asset – Lee COLA	383	—	—	—
Storm cost deferrals	1,117	531	953	526
Nuclear asset securitized balance, net	1,093	1,142	1,093	1,142
Hedge costs deferrals	204	234	74	94
Derivatives – natural gas supply contracts	141	142	—	—
Demand side management (DSM)/Energy efficiency (EE)	449	530	256	281
Grid modernization	31	39	—	—
Vacation accrual	213	213	41	42
Deferred fuel and purchased power	838	507	600	349
Nuclear deferral	133	119	46	35
Post-in-service carrying costs (PISCC) and deferred operating expenses	320	366	36	38
Transmission expansion obligation	39	46	—	—
Manufactured gas plant (MGP)	99	91	—	—
Advanced metering infrastructure (AMI)	367	362	127	150
NCEMPA deferrals	50	53	50	53
East Bend deferrals	47	45	—	—
Deferred pipeline integrity costs	65	54	—	—
Amounts due from customers	24	64	—	—
Other	784	538	322	110
Total regulatory assets	15,622	13,879	7,701	6,751
Less: current portion	2,005	1,437	1,137	741
Total noncurrent regulatory assets	$ 13,617	$ 12,442	$ 6,564	$ 6,010
Regulatory Liabilities				
Costs of removal	$ 5,421	$ 5,968	$ 2,135	$ 2,537
AROs – nuclear and other	538	806	—	—
Net regulatory liability related to income taxes	8,058	8,113	2,710	2,802
Amounts to be refunded to customers	34	10	—	—
Storm reserve	—	20	—	—

Accrued pension and OPEB	**301**	146	**149**	—
Deferred fuel and purchased power	**16**	47	**16**	1
Other	**1,064**	622	**319**	179
Total regulatory liabilities	**15,432**	15,732	**5,329**	5,519
Less: current portion	**598**	402	**280**	213
Total noncurrent regulatory liabilities	**$ 14,834**	$ 15,330	**$ 5,049**	$ 5,306

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 9 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 9 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 asset is expected to be recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 22 for additional detail.

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

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.

Net regulatory asset or liability related to income taxes. Amounts for all registrants include regulatory liabilities related primarily to impacts from the Tax Act. See Note 23 for additional information. Amounts have no immediate impact on rate base as regulatory assets are offset by deferred tax liabilities.

Deferred asset – Lee COLA. Represents deferred costs incurred for the canceled Lee nuclear project.

Storm cost deferrals. Represents deferred incremental costs incurred related to extraordinary 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.

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.

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

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

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

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

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.

Post-in-service carrying costs 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.

Transmission expansion obligation. Represents transmission expansion obligations related to Duke Energy Ohio's withdrawal from Midcontinent Independent System Operator, Inc. (MISO).

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.

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.

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.

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

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

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.

Storm reserve. Amounts are used to offset future incurred costs for named storms as approved by regulatory commissions.

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, 2018.

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, 2018.

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 percent of total capital.

Duke Energy Kentucky is required to pay dividends solely out of retained earnings and to maintain a minimum of 35 percent 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

Grid Improvement – South Carolina

On June 22, 2018, Duke Energy Carolinas and Duke Energy Progress filed a joint petition with the PSCSC seeking an accounting order authorizing deferral of certain costs incurred in connection with grid reliability, resiliency and modernization work that is being performed under the companies' grid improvement initiative. On October 3, 2018, the PSCSC granted Duke Energy Carolinas' and Duke Energy Progress' joint petition, which authorizes the deferral of these costs until the rate effective dates of each Company's next general rate case.

Hurricane Florence, Hurricane Michael and Winter Storm Diego

In September 2018, Hurricane Florence made landfall and inflicted severe damage to the Duke Energy Carolinas and Duke Energy Progress territories in North Carolina and South Carolina. Approximately 2 million customers were impacted. The companies incurred approximately $500 million in incremental operation and maintenance expenses ($70 million and $430 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) and approximately $90 million in capital costs ($5 million and $85 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) which are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2018, resulting from the hurricane restoration efforts. Most of the operation and maintenance expenses are deferred in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2018. 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, 2018.

In October 2018, the remnants of Hurricane Michael inflicted severe damage to the Duke Energy Carolinas and Duke Energy Progress territories in North Carolina and South Carolina. Approximately 1 million customers were impacted. The companies incurred approximately $100 million in incremental operation and maintenance expenses ($75 million and $25 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) and approximately $21 million in capital costs ($12 million and $9 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) which are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2018, resulting from the hurricane restoration efforts. Most of the operation and maintenance expenses are deferred in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2018. 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, 2018.

In December 2018, Winter Storm Diego inflicted severe damage to the Duke Energy Carolinas and Duke Energy Progress territories in North Carolina and South Carolina. Approximately 800,000 customers were impacted. The companies incurred approximately $85 million in incremental operation and maintenance expenses ($60 million and $25 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) and approximately $9 million in capital costs ($7 million and $2 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) which are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2018, resulting from the winter storm restoration efforts. Most of the operation and maintenance expenses are deferred in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2018. 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, 2018.

On December 21, 2018, Duke Energy Carolinas and Duke Energy Progress filed with the NCUC petitions for approval to defer the incremental costs incurred to a regulatory asset for recovery in the next base rate case. The NCUC issued an order requesting comments on the deferral positions. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter. Duke Energy Progress filed a similar request 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.

North Carolina State Corporate Income Tax

On December 12, 2018, Duke Energy Carolinas and Duke Energy Progress filed requests to reduce their rates effective January 1, 2019, based on a reduction in North Carolina’s corporate income tax rate from 3 to 2.5 percent, as enacted by the General Assembly in Session Law 2017-57, which became law on June 28, 2017, with an effective date of January 1, 2019. On December 17, 2018, the NCUC issued orders approving the Duke Energy Carolinas and Duke Energy Progress rate decrements.

Duke Energy Carolinas

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2018**	**2017**	**a Return**	**Period Ends**
Regulatory Assets[(a)]				
AROs – coal ash	**$ 1,725**	$ 1,645	(i)	(b)
Accrued pension and OPEB	**581**	410		(j)
Retired generation facilities[(c)]	**21**	29	X	2023
Deferred Asset – Lee COLA	**383**	—		(b)
Storm cost deferrals	**160**	—	X	(b)
Hedge costs deferrals[(c)]	**101**	109	X	2041
DSM/EE	**169**	210	(h)	(h)
Vacation accrual	**78**	83	(e)	2019
Deferred fuel and purchased power	**196**	140	(f)	2020
Nuclear deferral	**87**	84		2020
PISCC[(c)]	**34**	35	X	(b)
AMI	**176**	185	X	(b)
Other	**266**	222		(b)
Total regulatory assets	**3,977**	3,152		
Less: current portion	**520**	299		
Total noncurrent regulatory assets	**$ 3,457**	$ 2,853		
Regulatory Liabilities[(a)]				
Costs of removal[(c)]	**$ 1,968**	$ 2,054	X	(g)
ARO – nuclear and other	**538**	806		(b)
Net regulatory liability related to income taxes[(d)]	**3,082**	3,028		(b)
Storm reserve[(c)]	**—**	20		(b)
Accrued pension and OPEB	**38**	44		(j)
Deferred fuel and purchased power	**—**	46	(f)	2020
Other	**572**	359		(b)
Total regulatory liabilities	**6,198**	6,357		
Less: current portion	**199**	126		
Total noncurrent regulatory liabilities	**$ 5,999**	$ 6,231		

(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 23.
(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 22 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 percent increase in annual base revenues. The rate increase was driven by capital investments subsequent to the previous base rate case, including the W.S. Lee CC discussed below, 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 Lee Nuclear Station discussed below.

On February 28, 2018, Duke Energy Carolinas and the North Carolina Public Staff (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 percent and a capital structure of 52 percent equity and 48 percent debt. As a result of the settlement, Duke Energy Carolinas recorded a pretax charge of approximately $4 million to Operation, maintenance and other on the Consolidated Statements of Operations.

On June 1, 2018, Duke Energy Carolinas and certain intervenors filed a Pilot Grid Rider Agreement and Stipulation (Grid Rider Stipulation) in which the parties agreed to the proposal Duke Energy Carolinas introduced in a post-hearing brief on April 27, 2018, along with additional commitments by Duke Energy Carolinas. Also on June 1, 2018, Duke Energy Carolinas and the Commercial Group filed a Partial Stipulation and Settlement Agreement to be considered in conjunction with the Stipulation.

Components of the Grid Rider Stipulation included:

- Duke Energy Carolinas would recover grid improvement costs through a pilot, three-year Grid Rider except for costs related to targeted undergrounding of power lines, cable and conduit replacement, and power pole replacement;
- Excluded costs were to be deferred with a return until Duke Energy Carolinas’ next base rate case proceeding; and
- Costs incurred during the three-year pilot, both rider recoverable and deferred, were subject to a 4.5 percent cumulative cap of total annual electric service revenue.

On June 22, 2018, the NCUC issued an order approving the Stipulation of Partial Settlement and requiring a revenue reduction. The order also included the following material components not covered in the Stipulation:

- Recovery of $554 million of deferred coal ash basin closure costs over a five-year period with a return at Duke Energy Carolinas' WACC;
- Assessment of a $70 million management penalty ratably over a five-year period by reducing the annual recovery of the deferred coal ash costs;
- Denial of Duke Energy Carolinas' request for recovery of future estimated ongoing annual coal ash costs of $201 million with approval to defer such costs with a return at Duke Energy Carolinas' WACC, to be considered for recovery in the next rate case;
- Inclusion in rates of costs related to the W.S. Lee CC, two new solar facilities, and AMI deployment as requested;
- Recovery of Lee Nuclear Station licensing and development cost of $347 million over a 12-year period, but denial of a return on the deferred balance of costs;
- Reduction in revenue related to lower income tax expense resulting from the Tax Act, and a requirement to maintain all excess deferred income tax (EDIT) resulting from the Tax Act in a regulatory liability account pending flow back to customers as approved by the commission at the earlier of three years or Duke Energy Carolinas’ next general rate case proceeding; and

- Denial of the proposed Grid Rider Stipulation related to grid improvement costs and denial of deferral accounting treatment of the costs at this time. Duke Energy Carolinas may petition for deferral of grid modernization costs outside of a general rate case proceeding if it can show financial hardship or a stipulation that includes greater consensus among intervening parties on costs being classified as grid modernization.

As a result of the 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 is primarily related to the denial of a return on the Lee Nuclear Project and for previously recognized return impacted by the coal ash management penalty described above. 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 have also filed Notices of Appeal to the North Carolina Supreme Court from the June 22, 2018, Order Accepting Stipulation, Deciding Contested Issues and Requiring Revenue Reduction. On August 8, 2018, the Public Staff filed a Notice of Cross 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 Public Staff contends the commission’s 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. The Appellee response briefs are due July 29, 2019. 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 10.0 percent increase in retail revenues. The rate increase is 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 includes 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 percent, and $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.

Duke Energy Carolinas also requested approval of its proposed Grid Improvement Plan, 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. An evidentiary hearing is scheduled to begin on March 21, 2019, and a decision and revised customer rates are expected by mid-2019. 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. Duke Energy Carolinas cannot predict the outcome of this matter.

W.S. Lee CC

On April 9, 2014, the PSCSC granted Duke Energy Carolinas and NCEMC a CECPCN for the construction and operation of a 750-megawatt (MW) combined-cycle natural gas-fired generating plant at Duke Energy Carolinas' existing William States Lee Generating Station in Anderson, South Carolina. Duke Energy Carolinas began construction in July 2015 and its share of the cost to build the facility was approximately $650 million, including AFUDC. Approximately $600 million is being recovered through base rate or deferral filings in North Carolina and South Carolina. The remaining amount will be included in future rate filings. The project commenced commercial operation on April 5, 2018. NCEMC owns approximately 13 percent of the project.

Lee Nuclear Station

In December 2007, Duke Energy Carolinas applied to the NRC for COLs for two Westinghouse AP1000 reactors for the proposed William States Lee III Nuclear Station to be located at a site in Cherokee County, South Carolina. The NCUC and PSCSC concurred with the prudency of Duke Energy Carolinas incurring certain project development and preconstruction costs through several separately issued orders, although full cost recovery is not guaranteed. In December 2016, the NRC issued a COL for each reactor. Duke Energy Carolinas is not required to build the nuclear reactors as a result of the COLs being issued.

The Duke Energy Carolinas 2017 North Carolina Rate Case filing discussed above included a request to cancel the development of the Lee Nuclear project, recover incurred licensing and development costs and maintain the license issued by the NRC as an option for potential future development. The cancellation request was due to the Westinghouse bankruptcy filing and other market activity. The NCUC Order issued on June 22, 2018, approved the cancellation of the Lee Nuclear Project, allowed Duke Energy Carolinas to continue to maintain the COLs, provided for recovery of the North Carolina retail allocation of project development costs, including AFUDC accrued through December 31, 2017, over 12 years and disallowed any return on the unamortized balance during the 12-year recovery period.

Given the repeal of certain sections of the Base Load Review Act in South Carolina combined with the cancellation of the project, Duke Energy Carolinas determined that it was no longer probable it would be allowed a return on its share of project development costs attributable to South Carolina. As a result, Duke Energy Carolinas recorded a pretax impairment in the second quarter of 2018 of $29 million within Impairment charges on the Consolidated Statements of Operations and Comprehensive Income.

South Carolina Petition

On June 22, 2018, Duke Energy Carolinas filed a petition with the PSCSC requesting an accounting order to defer certain costs incurred in connection with the addition of the W.S. Lee CC, the ongoing deployment of Duke Energy Carolinas new billing and Customer Information System and the addition of the Carolinas West Primary Distribution Control Center. This request totaling approximately $33 million was approved on July 25, 2018.

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 is subject to approval from FERC for the four FERC-licensed plants, as well as other state regulatory agencies and is 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 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 September 4, 2018, the Public Staff filed comments supporting the CPCN transfer with conditions. On September 18, 2018, Duke Energy Carolinas filed reply comments opposing the Public Staff's proposed conditions. On November 29, 2018, the NCUC issued a procedural order and held an evidentiary hearing on this matter on February 5, 2019. On August 28, 2018, Duke Energy Carolinas filed with PSCSC its 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. 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 ("Order") 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 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, given that compliance by the deadline set in the Order is not possible because the conveyance of the projects is contingent on the receipt of state regulatory approvals, which are not anticipated to be issued by February 25, 2019.

If commission approvals are not received, Duke Energy Carolinas can cancel the sales agreement and retain the hydro facilities. If commission approvals are received, the closing is expected to occur during the second quarter of 2019. After closing, 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 Carolinas cannot predict the outcome of this matter.

Duke Energy Progress

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2018**	**2017**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs – coal ash	**$ 2,051**	$ 1,975	(h)	(b)
AROs – nuclear and other	**429**	359		(c)
Accrued pension and OPEB	**542**	430		(k)
Retired generation facilities	**148**	170	X	(b)
Storm cost deferrals[d]	**571**	150	X	(b)
Hedge costs deferrals	**54**	64		(b)
DSM/EE[e]	**235**	264	(i)	(i)
Vacation accrual	**41**	42		2019
Deferred fuel and purchased power	**397**	130	(f)	2020
Nuclear deferral	**46**	35		2020
PISCC and deferred operating expenses	**36**	38	X	2054
AMI	**67**	75		(b)
NCEMPA deferrals	**50**	53	(g)	2042
Other	**147**	74		(b)
Total regulatory assets	**4,814**	3,859		
Less: current portion	**703**	352		
Total noncurrent regulatory assets	**$ 4,111**	$ 3,507		
Regulatory Liabilities[a]				
Costs of removal	**$ 1,878**	$ 2,122	X	(j)
Accrued pension and OPEB	**93**	—		(k)
Net regulatory liability related to income taxes[l]	**1,863**	1,854		(b)
Deferred fuel and purchased power	**—**	1	(f)	2020
Other	**299**	161		(b)
Total regulatory liabilities	**4,133**	4,138		
Less: current portion	**178**	139		
Total noncurrent regulatory liabilities	**$ 3,955**	$ 3,999		

(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) 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 22 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 percent increase in annual base revenues. Subsequent to the filing, Duke Energy Progress adjusted the requested amount to $420 million, representing an approximate 13 percent increase. The rate increase is 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 December 16, 2016, Duke Energy Progress filed a petition with the NCUC requesting an accounting order to defer certain costs incurred in connection with response to Hurricane Matthew and other significant storms in 2016. The final estimate of incremental operation and maintenance and capital costs of $116 million was filed with the NCUC in September 2017. On July 10, 2017, the NCUC consolidated Duke Energy Progress' storm deferral request into the Duke Energy Progress rate case docket for decision.

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 percent and a capital structure of 52 percent equity and 48 percent debt. As a result of the settlement, in 2017 Duke Energy Progress recorded pretax charges totaling approximately $25 million to Impairment charges and Operation, maintenance and other on the Consolidated Statements of Operations, principally related to disallowances from rate base of certain projects at the Mayo and Sutton plants. On February 23, 2018, the NCUC issued an order approving the stipulation. The order also included the following material components not covered in the stipulation:

- Recovery of the remaining $234 million of deferred coal ash basin closure costs over a five-year period with a return at Duke Energy Progress' WACC, excluding $10 million of retail deferred coal ash basin costs related to ash hauling at Duke Energy Progress' Asheville Plant;
- Assessment of a $30 million management penalty ratably over a five-year period by reducing the annual recovery of the deferred coal ash costs;
- Denial of Duke Energy Progress' request for recovery of future estimated ongoing annual coal ash costs of $129 million with approval to defer such costs with a return at Duke Energy Progress' WACC, to be considered for recovery in the next rate case; and
- Approval to recover $51 million of the approximately $80 million deferred storm costs over a five-year period with amortization beginning in October 2016. The order did not allow the deferral of the associated capital costs or a return on the deferred balance during the deferral period.

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. These charges primarily related to the coal ash basin disallowance and previously recognized return impacted by the coal ash management penalty and deferred storm cost adjustments. 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 February 23, 2018, Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase issued by the NCUC. The Public Staff contend the commission'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 have also filed Notices of Appeal to the North Carolina Supreme Court from the February 23, 2018, Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase. 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. On November 29, 2018, the North Carolina Supreme Court adopted a schedule for briefing set forth in the motion to consolidate the Duke Energy Progress and Duke Energy Carolinas appeals. The Appellee response briefs are due July 29, 2019. Duke Energy Progress cannot predict the outcome of this matter.

2016 South Carolina Rate Case

In December 2016, the PSCSC approved a rate case settlement agreement among the ORS, intervenors and Duke Energy Progress. Terms of the settlement agreement included an approximate $56 million increase in revenues over a two-year period. An increase of approximately $38 million in revenues was effective January 1, 2017, and an additional increase of approximately $19 million in revenues was effective January 1, 2018. Duke Energy Progress amortized approximately $19 million from the cost of removal reserve in 2017. Other settlement terms included a rate of return on equity of 10.1 percent, recovery of coal ash costs incurred from January 1, 2015, through June 30, 2016, over a 15-year period and ongoing deferral of allocated ash basin closure costs from July 1, 2016, until the next base rate case. The settlement also provides that Duke Energy Progress will not seek an increase in rates in South Carolina to occur prior to 2019, with limited exceptions.

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 percent increase in annual base revenues. The rate increase is 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 includes net tax benefits of $15 million consisting of a $12 million increase due to the expiration of EDITs related to reductions in North Carolina state income taxes allocable to South Carolina and decreases 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 percent, and $10 million to return EDIT resulting from the federal tax rate change and deferred revenues since January 2018 related to the change.

Duke Energy Progress also requested approval of its proposed Grid Improvement Plan, 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. An evidentiary hearing is scheduled to begin on April 11, 2019, and a decision and revised customer rates are expected by mid-2019. 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. These investments will be made within the next seven years. Duke Energy Progress is also working with the local natural gas distribution company to upgrade an existing natural gas pipeline to serve the natural gas plant.

On March 28, 2016, the NCUC issued an order approving a CPCN for the new combined-cycle natural gas plants, but denying the CPCN for the contingent simple cycle unit without prejudice to Duke Energy Progress to refile for approval in the future. On March 28, 2018, 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. Site preparation activities for the combined-cycle plants are complete and construction of these plants began in 2017, with an expected in-service date in late 2019.

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 November 30, 2018, the NCUC issued an order scheduling hearings, requiring filing of testimony, establishing discovery guidelines and requiring public notice. On February 7, 2019, Duke Energy Progress made a joint filing with the Public Staff, which accepted the Public Staff's proposed conditions and requested that the NCUC cancel the evidentiary hearing. Duke Energy Progress cannot predict the outcome of this matter.

The carrying value of the 376-MW Asheville coal-fired plant, including associated ash basin closure costs, of $327 million and $385 million is included in Generation facilities to be retired, net on Duke Energy Progress' Consolidated Balance Sheets as of December 31, 2018, and 2017, 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.

Shearon Harris Nuclear Plant Expansion

In 2006, Duke Energy Progress selected a site at Harris to evaluate for possible future nuclear expansion. On February 19, 2008, Duke Energy Progress filed its COL application with the NRC for two Westinghouse AP1000 reactors at Harris, which the NRC docketed for review. On May 2, 2013, Duke Energy Progress filed a letter with the NRC requesting the NRC to suspend its review activities associated with the COL at the Harris site. The NCUC and PSCSC approved deferral of retail costs. Total deferred costs are approximately $43 million as of December 31, 2018, and are recorded in Regulatory assets on Duke Energy Progress’ Consolidated Balance Sheets. On November 17, 2016, the FERC approved Duke Energy Progress’ rate recovery request filing for the wholesale ratepayers’ share of the abandonment costs, including a debt-only return to be recovered through revised formula rates and amortized over a 15-year period beginning May 1, 2014. As part of the settlement agreement for the 2017 North Carolina Rate Case discussed above, Duke Energy Progress will amortize the regulatory asset over an eight-year period. NCUC approved the settlement on February 23, 2018.

South Carolina Petitions

On June 22, 2018, Duke Energy Progress filed a petition with the PSCSC seeking an accounting order authorizing Duke Energy Progress to adopt new depreciation rates, effective March 16, 2018, that reflect the results of Duke Energy Progress’ most recent depreciation study. Also on June 22, 2018, Duke Energy Progress filed a petition with the PSCSC requesting an accounting order to defer certain costs incurred in connection with the deployment of AMI, the ongoing deployment of Duke Energy Progress' new billing and Customer Information System, new depreciation rates and costs incurred in connection with the return of certain excess deferred state income taxes from North Carolina. These requests totaling approximately $20 million were approved on July 25, 2018.

FERC Form 1 Reporting Matter

On October 18, 2017, Fayetteville Public Works Commission (FPWC) filed with FERC a complaint against Duke Energy Progress. In the complaint, FPWC alleges that Duke Energy Progress’ change in its method of reporting materials and supplies inventory on FERC Form 1 for 2015 constituted a change in accounting practice that Duke Energy Progress was not permitted to implement without first obtaining FERC approval. On April 23, 2018, FERC issued an order finding that Duke Energy Progress’ new reporting methodology was not proper and required Duke Energy Progress to revise its FERC Form 1s beginning in 2014 and to issue refunds to formula rate customers. Duke Energy Progress estimates that these refunds will total approximately $14 million. On May 23, 2018, Duke Energy Progress filed a request for rehearing alleging that FERC’s order is incorrect. Duke Energy Progress revised its FERC Form 1 filings in June 2018. On August 31, 2018, Duke Energy Progress filed with FERC a refund report memorializing its payment of refunds to FPWC. Duke Energy Progress cannot predict the outcome of this matter.

Tax Act

As ordered by the NCUC on October 5, 2018, Duke Energy Progress filed a proposal on October 25, 2018, to adjust rates to reflect the reduction in federal corporate income tax rate from 35 to 21 percent for taxable years beginning after December 31, 2017, as outlined in the Tax Act. Duke Energy Progress proposed that this rate decrement be effective for service rendered on and after December 1, 2018. On November 28, 2018, the NCUC approved the proposal to implement the change in the federal corporate income tax rate and effective December 1, 2018, Duke Energy Progress implemented the rate reduction. Also, as ordered by the NCUC on October 5, 2018, Duke Energy Progress shall continue to hold in a deferred regulatory liability account the difference between revenues billed under the prior federal corporate income tax rate and the federal corporate income tax rate resulting from the Tax Act for the period January 1, 2018 through November 30, 2018. The disposition of such regulatory liability may be considered in Duke Energy Progress' next general rate case proceeding or in three years, whichever is sooner. EDIT related to the corporate income tax rate reduction shall be held in a deferred tax regulatory liability account until they can be addressed for ratemaking purposes in the next general rate case proceeding or in three years, whichever is sooner.

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.

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	2018	2017	a Return	Period Ends
Regulatory Assets[a]				
AROs – coal ash[c]	$ **10**	$ 9		(b)
AROs – nuclear and other[c]	**172**	296		(b)
Accrued pension and OPEB[c]	**532**	476	X	(g)
Retired generation facilities[c]	**219**	216	X	(b)
Storm cost deferrals[c][h]	**382**	376	(e)	2021
Nuclear asset securitized balance, net	**1,093**	1,142		2036
Hedge costs deferrals	**20**	30		2020
DSM/EE[c]	**21**	17	X	2023
Deferred fuel and purchased power[c]	**203**	219	(f)	2020
AMI[c]	**60**	75	X	2032
Other	**176**	36	(d)	(b)
Total regulatory assets	**2,888**	2,892		
Less: current portion	**434**	389		
Total noncurrent regulatory assets	$ **2,454**	$ 2,503		
Regulatory Liabilities[a]				
Costs of removal[c]	$ **257**	$ 415	(d)	(b)
Net regulatory liability related to income taxes[c]	**847**	948		(b)
Accrued pension and OPEB	**56**	—	X	(g)
Deferred fuel and purchased power[c]	**16**	—	(f)	2020
Other	**20**	18	(d)	(b)
Total regulatory liabilities	**1,196**	1,381		
Less: current portion	**102**	74		
Total noncurrent regulatory liabilities	$ **1,094**	$ 1,307		

(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 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 22 for additional detail.
(h) Balance includes $165 million for Hurricane Michael. Duke Energy Florida expects to seek recovery of these costs in the first half of 2019.

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. Storm costs are currently expected to be fully recovered by approximately mid-2021. 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 is seeking 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. The commission has scheduled the hearing to begin on May 21, 2019. At December 31, 2018, Duke Energy Florida's Consolidated Balance Sheets included approximately $217 million 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. Duke Energy Florida cannot predict the outcome of this matter.

In October 2018, Duke Energy Florida's service territory suffered damage when Hurricane Michael made landfall as a strong Category 4 hurricane with maximum sustained winds of 155 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. Duke Energy Florida incurred approximately $200 million of costs resulting from the hurricane restoration efforts. Approximately $35 million of the costs are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2018. The remaining $165 million of costs represent recoverable costs under the FPSC's storm rule and Duke Energy Florida's Open Access Transmission Tariff formula rates and are included in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2018. Duke Energy Florida anticipates filing a petition with the FPSC in the first half of 2019 to recover these costs, consistent with the provisions in the 2017 Settlement. 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. 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 will seek a Private Letter Ruling from the IRS on its treatment of 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. Duke Energy Florida cannot predict the outcome of this matter.

Citrus County CC

On October 2, 2014, the FPSC granted Duke Energy Florida a Determination of Need for the construction of a 1,640-MW combined-cycle natural gas plant in Citrus County, Florida. At that time, the estimated cost of the facility was $1.5 billion, including AFUDC. On May 5, 2015, the Florida Department of Environmental Protection approved Duke Energy Florida's Site Certification Application and construction began in October 2015. On July 10, 2018, the FPSC approved Duke Energy Florida's request to include the annual revenue requirement of $200 million for the new Citrus County combined-cycle units in base rates. The first 820-MW power block came on-line on October 26, 2018, and the rate increase for this unit was effective in December 2018. The second 820-MW power block came on-line November 24, 2018. The rate increase for the second unit was effective in January 2019. The ultimate cost of the facility is 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, which may change in light of recoveries from the EPC contractor. The plant began receiving natural gas from the Sabal Trail pipeline in August 2018. As a result of the combined-cycle natural gas plant coming on-line, Crystal River coal-fired units 1 and 2 were retired in December 2018. See Note 5 for additional information on Citrus.

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 and the increase was 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. 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. Rates are subject to true up pending the outcome of the final hearing, which is scheduled to take place on April 2, 2019. 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.

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2018**	**2017**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs – coal ash	**$ 20**	$ 17	X	(b)
Accrued pension and OPEB	**146**	139		(g)
Storm cost deferrals	**4**	5		2023
Hedge costs deferrals	**5**	6		(b)
DSM/EE	**10**	18	(f)	(e)
Grid modernization	**31**	39	X	(e)
Vacation accrual	**5**	5		2019
Deferred fuel and purchased power	**2**	—		2019
PISCC and deferred operating expenses[c]	**17**	19	X	2083
Transmission expansion obligation	**43**	50		(e)
MGP	**99**	91		(b)
AMI	**46**	6		(b)
East Bend deferrals	**47**	45	X	(b)
Deferred pipeline integrity costs	**14**	12	X	(b)
Other	**75**	42		(b)
Total regulatory assets	**564**	494		
Less: current portion	**33**	49		
Total noncurrent regulatory assets	**$ 531**	$ 445		
Regulatory Liabilities[a]				
Costs of removal	**$ 126**	$ 189		(d)
Net regulatory liability related to income taxes	**678**	688		(b)
Accrued pension and OPEB	**18**	16		(g)
Other	**75**	34		(b)
Total regulatory liabilities	**897**	927		
Less: current portion	**57**	36		
Total noncurrent regulatory liabilities	**$ 840**	$ 891		

(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 22 for additional detail.

2017 Electric Security Plan

On June 1, 2017, Duke Energy Ohio filed with the PUCO a request for a standard service offer in the form of an 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 currently 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 includes 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 establishes a regulatory model for the next seven years via the approval of the ESP and continues 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 have filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. 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 percent. 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 percent and 10.24 percent. 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 include a $19 million decrease in annual base distribution revenue with a return on equity unchanged from the current rate of 9.84 percent based upon a capital structure of 50.75 percent equity and 49.25 percent debt. Upon approval of new rates, Duke Energy Ohio's rider for recovering its initial SmartGrid implementation ends as these costs will be recovered through base rates. The Stipulation also renews 14 existing riders, some of which were included in the company's ESP, and adds 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 reduces 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 have filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. 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 price stabilization rider (Rider PSR), which is currently set at zero dollars, 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 are 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 activates 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. Several parties have filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. Duke Energy Ohio cannot predict the outcome of this matter. See Note 17 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. Duke Energy Ohio requested commission approval to implement the rider effective October 1, 2018, as a credit to all distribution customers based upon a percent reduction to Duke Energy Ohio's distribution rates. The new rider will flow through to customers the benefit of the lower statutory federal tax rate from 35 to 21 percent 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 rate-making 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 will be 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 percent 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 has not yet ruled on the application for changes for natural gas customers. 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. Duke Energy Ohio cannot predict the outcome of this matter.

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 Ohio Consumers' Counsel'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. Duke Energy Ohio cannot predict the outcome of this matter.

2014 Electric Security Plan

In April 2015, the PUCO modified and approved Duke Energy Ohio's proposed ESP, with a three-year term and an effective date of June 1, 2015. The PUCO approved a competitive procurement process for SSO load, a distribution capital investment rider (Rider DCI) and a tracking mechanism for incremental distribution expenses caused by major storms. The PUCO also approved a placeholder tariff for a price stabilization rider, but denied Duke Energy Ohio's specific request to include Duke Energy Ohio's entitlement to generation from OVEC in the rider at this time; however, the order allows Duke Energy Ohio to submit additional information to request recovery in the future. On May 4, 2015, Duke Energy Ohio filed an application for rehearing requesting the PUCO to modify or amend certain aspects of the order. On May 28, 2015, the PUCO granted all applications for rehearing filed in the case for future consideration. On March 21, 2018, the PUCO issued an order denying Duke Energy Ohio's issues on rehearing. On April 20, 2018, Duke Energy Ohio filed a second application for rehearing based upon the commission's March 21, 2018, Order. On May 16, 2018, the commission issued its third Entry on Rehearing granting in part, and denying in part, Duke Energy Ohio's rehearing request.

On March 9, 2018, Duke Energy Ohio filed a motion to extend its then-current ESP, including all terms and conditions thereof, pending approval of a new ESP. On May 30, 2018, the PUCO granted the request, with modification. Specifically, the PUCO did not extend the cap applicable to Rider DCI beyond July 31, 2018. Duke Energy Ohio sought rehearing of this finding. On July 25, 2018, the PUCO granted the request and allowed a continuing cap on recovery under Rider DCI. On August 24, 2018, OMA and OCC filed an Application for Rehearing of the commission's decision. Duke Energy Ohio filed a Memorandum Contra OCC's request for rehearing of the commission's continuation of Rider DCI on September 4, 2018. On September 19, 2018, the PUCO issued an Order granting rehearing on the matter for further consideration. Duke Energy Ohio cannot predict the outcome of this matter.

On May 21, 2018, the Ohio Manufacturers' Association (OMA) filed a notice of appeal of PUCO's approval of Duke Energy Ohio’s ESP with the Ohio Supreme Court, challenging PUCO's approval of Duke Energy Ohio’s Price Stability Rider as a placeholder and its Rider DCI to recover incremental revenue requirement for distribution capital since Duke Energy Ohio’s last base rate case. On July 16, 2018, the Office of the Ohio Consumers' Counsel (OCC) filed its own appeal of Duke Energy Ohio’s ESP with the Ohio Supreme Court raising similar issues to that of the OMA. Duke Energy Ohio filed a Motion to Intervene in the two Ohio Supreme Court appeals. OMA's Supreme Court brief was filed on August 20, 2018. PUCO submitted its brief on October 26, 2018, and Duke Energy Ohio filed its brief on October 29, 2018. The OCC’s Supreme Court brief was filed on October 15, 2018. Duke Energy Ohio filed its brief on December 20, 2018. The PUCO submitted its brief on December 21, 2018. Duke Energy Ohio cannot predict the outcome of this matter.

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 includes a local public hearing on March 21, 2019, and an evidentiary hearing starting on April 9, 2019. If approved, 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

On November 13, 2013, the PUCO issued an order approving a settlement of Duke Energy Ohio’s natural gas base rate case and authorizing the recovery of costs incurred between 2008 and 2012 for environmental investigation and remediation of two former MGP sites. The PUCO order also authorized Duke Energy Ohio to continue deferring MGP environmental investigation and remediation costs incurred subsequent to 2012 and to submit annual filings to adjust the MGP rider for future costs. Intervening parties appealed this decision to the Ohio Supreme Court and on June 29, 2017, the Ohio Supreme Court issued its decision affirming the PUCO order. Appellants filed a request for reconsideration, which was denied on September 27, 2017. This matter is now final.

The PUCO order also contained conditional deadlines for completing the MGP environmental investigation and remediation costs at the MGP sites. As of December 31, 2018, Duke Energy Ohio had approximately $24 million for future remediation costs expected to be incurred at the East End site and approximately $23 million for future remediation costs expected to be incurred at the West End site included in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets.

Duke Energy Kentucky Electric Rate Case

On September 1, 2017, Duke Energy Kentucky filed a rate case with the KPSC requesting an increase in electric base rates of approximately $49 million, which represents an approximate 15 percent increase on the average customer bill. Subsequent to the filing, Duke Energy Kentucky adjusted the requested amount to $30.1 million, in part to reflect the benefits of the Tax Act, representing an approximate 9 percent increase on the average customer bill. The rate increase was driven by increased investment in utility plant, increased operations and maintenance expenses and recovery of regulatory assets. The application also includes requests to implement an Environmental Surcharge Mechanism to recover environmental costs not recovered in base rates, to establish a Distribution Capital Investment Rider to recover incremental costs of specific programs, to establish a FERC Transmission Cost Reconciliation Rider to recover escalating transmission costs and to modify existing Profit Sharing Mechanism to increase customers' share of proceeds from the benefits of owning generation and to mitigate shareholder risks associated with that generation. An evidentiary hearing concluded on March 8, 2018, and the KPSC issued an order on April 13, 2018. Major components of the Order include approval of an $8 million increase in base rates with a return on equity at 9.725 percent based upon a capital structure of 49 percent equity on a total allocable capitalization of approximately $650 million. The Order approved the Environmental Surcharge Mechanism Rider and in June 2018 recovery began of capital-related environmental costs, including costs related to ash and ash disposal, and environmental operation and maintenance expenses formerly recovered in base rates, including expenses for environmental reagents and emission allowances. The incremental revenue from this rider will be approximately $13 million on an annualized basis. The order settles all issues associated with the Tax Act as it relates to the electric business by lowering the income tax component of the revenue requirement and refunding protected EDIT under allowable normalization rules and unprotected EDIT over 10 years. The Order denied requests to implement riders for certain transmission costs and distribution capital investments. Duke Energy Kentucky implemented new base rates on May 1, 2018. On May 3, 2018, Duke Energy Kentucky filed an application for rehearing on certain aspects of the order; on May 23, 2018, the KPSC granted a rehearing. On October 2, 2018, the KPSC issued its rehearing order correcting certain findings in its initial order and making additional changes that are immaterial to the company's earnings.

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 percent average increase across all customer classes. The increase is net of approximately $5 million in annual savings as a result of the Tax Act. The drivers for this case are capital invested since Duke Energy Kentucky's last rate case in 2009. Duke Energy Kentucky is also seeking 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, which if approved would resolve the matter. The settlement provides for an approximate $7 million increase and approval of the proposed Weather Normalization Mechanism. A hearing was held on February 5, 2019. A ruling is expected in late first quarter 2019. Duke Energy Kentucky cannot predict the outcome of this matter.

FERC 494 Refund of Regional Transmission Enhancement Projects

FERC Order No. 494 Settlement Agreement (FERC 494 Settlement Agreement) was entered into by most of the PJM transmission owners, including Duke Energy Ohio and Duke Energy Kentucky, and the PJM state regulatory commissions approximately two years ago and was planned to be effective on January 1, 2016; however, it was not approved by FERC until May 31, 2018. The FERC 494 Settlement Agreement was due to the Seventh Circuit Court of Appeals finding that FERC had failed to adequately justify the costs that the customers in the western part of PJM were being charged for high voltage transmission projects, or Regional Transmission Expansion Plan (RTEP) projects (500 kV and above) built in the east. These costs were being allocated to all PJM customers on a load-ratio share basis but the court determined that these costs were not justifiable to customers in the west, including Duke Energy Ohio and Duke Energy Kentucky, that did not benefit from the RTEP projects. Costs for the periods 2012 through 2015 are expected to be refunded to Duke Energy Ohio and Duke Energy Kentucky on a monthly basis through December 2025. The refund amount for similar costs incurred beginning in 2016 through June 30, 2018, prior to the change in cost allocation by PJM was determined in the third quarter of 2018 and these amounts will be refunded over a 12-month period beginning in July 2018. These refunds, totaling approximately $47 million for Duke Energy Ohio and Duke Energy Kentucky, have been recorded to Operation, maintenance and other on the Consolidated Statements of Operations for the year ended December 31, 2018.

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 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, 2018, and 2017, $43 million and $50 million, respectively, are recorded in Regulatory assets on Duke Energy Ohio's Consolidated Balance Sheets.

(in millions)	December 31, 2017	Provisions/ Adjustments	Cash Reductions	December 31, 2018
Duke Energy Ohio	$ 66	$ (4)	$ (4)	$ 58

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, 2018	December 31, 2017	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[(a)]				
AROs – coal ash	$ 450	$ 380		(b)
Accrued pension and OPEB	222	197		(f)
Retired generation facilities[(c)]	57	65	X	2026
Hedge costs deferrals	24	25		(b)
DSM/EE	14	21	(e)	(e)
Vacation accrual	11	11		2019
Deferred fuel and purchased power	40	18		2019
PISCC and deferred operating expenses[(c)]	233	274	X	(b)
AMI[(c)]	18	21	X	(b)
Other	88	131		(b)
Total regulatory assets	1,157	1,143		
Less: current portion	175	165		
Total noncurrent regulatory assets	$ 982	$ 978		
Regulatory Liabilities[(a)]				
Costs of removal	$ 628	$ 644		(d)
Net regulatory liability related to income taxes	1,009	998		(b)
Amounts to be refunded to customers	1	10		2019
Accrued pension and OPEB	67	64		(f)
Other	42	31		(b)
Total regulatory liabilities	1,747	1,747		
Less: current portion	25	24		
Total noncurrent regulatory liabilities	$ 1,722	$ 1,723		

(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) 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 22 for additional detail.

FERC Transmission Return on Equity Complaint

Customer groups have filed with the FERC complaints against Midcontinent Independent System Operator, Inc. (MISO) and its transmission-owning members, including Duke Energy Indiana, alleging, among other things, that the current base rate of return on equity earned by MISO transmission owners of 12.38 percent is unjust and unreasonable. The complaints claim, among other things, that the current base rate of return on equity earned by MISO transmission owners should be reduced to 8.67 percent. On January 5, 2015, the FERC issued an order accepting the MISO transmission owners' adder of 0.50 percent to the base rate of return on equity based on participation in an RTO subject to it being applied to a return on equity that is shown to be just and reasonable in the pending return on equity complaints. On December 22, 2015, the presiding FERC ALJ in the first complaint issued an Initial Decision in which the base rate of return on equity was set at 10.32 percent. On September 28, 2016, the Initial Decision in the first complaint was affirmed by FERC, but is subject to rehearing requests. On June 30, 2016, the presiding FERC ALJ in the second complaint issued an Initial Decision setting the base rate of return on equity at 9.70 percent. The Initial Decision in the second complaint is pending FERC review. On April 14, 2017, the U.S. Court of Appeals for the District of Columbia Circuit, in *Emera Maine v. FERC*, reversed and remanded certain aspects of the methodology employed by FERC to establish rates of return on equity. On October 16, 2018, FERC issued an order in response to the Emera remand proceeding proposing a new method for determining whether an existing return on equity is unjust and unreasonable, and a new process for determining a just and reasonable return on equity. On November 14, 2018, FERC directed parties to the MISO complaints to file briefs on how the new process for determining return on equity proposed in the Emera proceeding should be applied to the complaints involving the MISO transmission owners' return on equity. Initial briefs were filed on February 13, 2019, and reply briefs will be due April 10, 2019. Duke Energy Indiana currently believes these matters will not have a material impact on its results of operations, cash flows and financial position.

Benton County Wind Farm Dispute

On December 16, 2013, BCWF filed a lawsuit against Duke Energy Indiana seeking damages for past generation losses alleging Duke Energy Indiana violated its obligations under a 2006 PPA by refusing to offer electricity to the market at negative prices. Damage claims continue to increase during times that BCWF is not dispatched. Under 2013 revised MISO market rules, Duke Energy Indiana is required to make a price offer to MISO for the power it proposes to sell into MISO markets and MISO determines whether BCWF is dispatched. Because market prices would have been negative due to increased market participation, Duke Energy Indiana determined it would not bid at negative prices in order to balance customer needs against BCWF's need to run. BCWF contends Duke Energy Indiana must bid at the lowest negative price to ensure dispatch, while Duke Energy Indiana contends it is not obligated to bid at any particular price, that it cannot ensure dispatch with any bid and that it has reasonably balanced the parties' interests. On July 6, 2015, the U.S. District Court for the Southern District of Indiana entered judgment against BCWF on all claims. BCWF appealed the decision and on December 9, 2016, the appeals court ruled in favor of BCWF. Duke Energy Indiana recorded an obligation and a regulatory asset related to the settlement amount in fourth quarter 2016. On June 30, 2017, the parties finalized a settlement agreement. Terms of the settlement included Duke Energy Indiana paying $29 million for back damages. Additionally, the parties agreed on the method by which the contract will be bid into the market in the future. The settlement amount was paid in June 2017. The IURC issued an order on September 27, 2017, approving recovery of the settlement amount through Duke Energy Indiana's fuel clause. The IURC order has been appealed to the Indiana Court of Appeals. On May 21, 2018, the Indiana Court of Appeals upheld the commission's decision. The appellants have requested rehearing at the Indiana Court of Appeals. The Indiana Court of Appeals denied the request for rehearing. The appellants have requested transfer to the Indiana Supreme Court, including briefs in support from environmental groups. The Indiana Supreme Court denied transfer concluding this matter in favor of Duke Energy Indiana.

Edwardsport Integrated Gasification Combined Cycle 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 is expected to be filed in mid-2019 with rates effective in mid-2020. It addresses the pending Edwardsport filing at the commission and eliminates the need for future filings until the overall rate case. This settlement includes caps on Duke Energy Indiana's retail operating expenses for 2018 and 2019, reduces Duke Energy Indiana's regulatory asset by $30 million (with a corresponding reduction of the amount of amortization of the regulatory asset included in rates by $10 million annually beginning with the implementation of final IGCC 17 rates), and provides funding for low-income assistance and clean energy projects. Duke Energy Indiana recognized pretax impairment and related charges of $32 million in the third quarter of 2018. The settlement is subject to IURC approval. An evidentiary hearing was held December 2018 and an IURC Order is expected in March 2019. Duke Energy Indiana cannot predict the outcome of this matter.

Tax Act

On June 27, 2018, Duke Energy Indiana, the Indiana Office of Utility Consumer Counselor, the Indiana Industrial Group and Nucor Steel – Indiana filed testimony consistent with their Stipulation and Settlement Agreement (Settlement Agreement) in the federal tax act proceeding with the IURC. The Settlement Agreement outlines how Duke Energy Indiana will implement the impacts of the Tax Act. Material components of the Settlement Agreement were as follows:

- Riders to reflect the change in the statutory federal tax rate from 35 to 21 percent as they are filed in 2018;
- Base rates to reflect the change in the statutory federal tax rate from 35 to 21 percent upon IURC approval, but no later than September 1, 2018;
- Duke Energy Indiana to continue to defer protected federal EDIT until January 1, 2020, at which time it will be returned to customers according to the Average Rate Assumption Method required by the Internal Revenue Service over approximately 26 years; and
- Duke Energy Indiana to begin returning unprotected federal EDIT upon IURC approval, over 10 years. In order to mitigate the negative impacts to cash flow and credit metrics, the Settlement Agreement allows Duke Energy Indiana to return $7 million per year over the first five years, with a step up to $35 million per year in the following five years.

On August 22, 2018, the IURC approved the settlement and rates were adjusted effective September 1, 2018.

Piedmont

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	2018	2017	a Return	Period Ends
Regulatory Assets[a]				
AROs – other	**$ 19**	$ 15		(d)
Accrued pension and OPEB[c]	**99**	91	X	(f)
Derivatives – gas supply contracts[e]	**141**	142		
Vacation accrual	**12**	10		
Deferred pipeline integrity costs[c]	**51**	42	X	(b)
Amount due from customers	**24**	64	X	(b)
Other	**11**	14		(b)
Total regulatory assets	**357**	378		
Less: current portion	**54**	95		
Total noncurrent regulatory assets	**$ 303**	$ 283		
Regulatory Liabilities[a]				
Costs of removal	**$ 564**	$ 544		(d)
Net regulatory liability related to income taxes	**579**	597		(b)
Accrued pension and OPEB[c]	**1**	—	X	(f)
Amount due to customers	**33**	—	X	(b)
Other	**41**	3		(b)
Total regulatory liabilities	**1,218**	1,144		
Less: current portion	**37**	3		
Total noncurrent regulatory liabilities	**$ 1,181**	$ 1,141		

(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 22 for additional detail.

South Carolina Rate Stabilization Adjustment Filing

On June 15, 2018, Piedmont filed with the PSCSC under the South Carolina Rate Stabilization Act its quarterly monitoring report for the 12-month period ending March 31, 2018. The filing included a revenue deficiency calculation and tariff rates in order to permit Piedmont the opportunity to earn the rate of return on common equity established in its last general rate case. The filing also incorporated the impacts of the Tax Act by lowering the income tax component of the revenue requirement, refunding protected EDIT under allowable normalization rules, unprotected EDIT and amounts over collected from the customers from January 1, 2018, through the end of the review period for this proceeding. A settlement agreement reached between Piedmont and ORS was filed with the PSCSC on September 14, 2018, and approved by the PSCSC on October 3, 2018. Terms of the settlement include implementation of rates for the 12-month period beginning November 2018 with a return on equity of 10.2 percent.

North Carolina Integrity Management Rider Filing

In October 2018, Piedmont filed a petition under the IMR mechanism to collect an additional $10 million in annual revenues, effective December 2018, based on the eligible capital investments closed to integrity and safety projects over the six-month period ended September 30, 2018. On November 27, 2018, the NCUC approved the requested rate adjustment.

In May 2018, Piedmont filed, and the NCUC approved, a petition under the IMR mechanism to update rates, effective June 2018, based on the eligible capital investments closed to integrity and safety projects over the six-month period ending March 31, 2018, and the decrease in the corporate federal income tax rate effective January 1, 2018. The combined effect of the update was a reduction to annual revenues of approximately $6 million.

Tennessee Integrity Management Rider Filing

In November 2018, Piedmont filed a petition with the TPUC under the IMR mechanism to collect an additional $3 million in annual revenues, effective January 2019, based on the eligible capital investments closed to integrity and safety projects over the 12-month period ending October 31, 2018. A hearing on this matter is scheduled for March 2019.

2018 North Carolina Rate Case

On February 27, 2019, Piedmont filed a notice with the NCUC of its intent to file a base rate adjustment application no earlier than 30 days from the notice submittal date.

OTHER REGULATORY MATTERS

Progress Energy Merger FERC Mitigation

Since December 2014, the FERC Office of Enforcement has conducted an investigation of Duke Energy’s market power filings in its application for approval of the Progress Energy merger submitted in 2012. On June 8, 2018, the FERC issued an order approving a settlement agreement under which Duke Energy paid a penalty of $3.5 million. The FERC Office of Enforcement stated in its conclusion that Duke Energy violated FERC regulations by failing to fully and accurately describe certain specific matters in its market power filings. Duke Energy neither admitted nor denied the alleged violations.

Atlantic Coast Pipeline, LLC

On September 2, 2014, Duke Energy, Dominion Resources (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 percent. Duke Energy owns a 47 percent interest, which is accounted for as an equity method investment through its Gas Utilities and Infrastructure segment. Southern Company Gas maintains a 5 percent interest. See Notes 12 and 17 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. Immediately 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. We appreciate the professional and collaborative process by the permitting agencies designed to ensure that this critical energy infrastructure project will meet the stringent environmental standards required by law and regulation.

ACP is the subject of challenges in state and federal courts and agencies, including, among others, challenges of the project's 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 Virginia conditional 401 water quality certification, 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. ACP is vigorously defending these challenges and coordinating with the federal and state authorities which are the direct parties to the challenges. Since July 2018, notable developments in these challenges include a stay issued by the U.S. Court of Appeals for the Fourth Circuit (Fourth Circuit) on construction activities through the Monongahela and George Washington National Forests, a reissuance of the project's ITS and Blue Ridge Parkway right-of-way and renewed challenges of these reissued permits, a stay issued by the Fourth Circuit of the project's biological opinion and ITS (which stay has 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 and the Fourth Circuit's remand to USACE of ACP's Huntington District 404 verification.

The delays resulting from the legal challenges described above have impacted the cost and schedule for the project. As a result, project cost estimates have increased to $7.0 billion to $7.8 billion, excluding financing costs. ACP expects to achieve a late 2020 in-service date for key segments of the project, while it expects the remainder to extend into 2021. Abnormal weather, work delays (including delays due to judicial or regulatory action) and other conditions may result in cost or schedule modifications in the future.

Sabal Trail Transmission, LLC

On May 4, 2015, Duke Energy acquired a 7.5 percent ownership interest in Sabal Trail, which is accounted for as an equity method investment, from Spectra Energy Partners, LP, a master limited partnership, formed by Enbridge Inc. (formerly Spectra Energy Corp.). Spectra Energy Partners, LP holds a 50 percent ownership interest in Sabal Trail and NextEra Energy has a 42.5 percent ownership interest. Sabal Trail is a joint venture to construct a 515-mile natural gas pipeline (Sabal Trail pipeline) to transport natural gas to Florida. Total estimated project costs are approximately $3.2 billion. The Sabal Trail pipeline traverses Alabama, Georgia and Florida. The primary customers of the Sabal Trail pipeline, Duke Energy Florida and FP&L have each contracted to buy pipeline capacity for 25-year initial terms. See Notes 12 and 17 for additional information related to Duke Energy's ownership interest.

On February 3, 2016, the FERC issued an order granting the request for a CPCN to construct and operate the pipeline. The Sabal Trail pipeline received other required regulatory approvals and the Phase 1 mainline was placed in service in July 2017. On October 12, 2017, Sabal Trail filed a request with FERC to place in-service a lateral line to Duke Energy Florida's Citrus County CC. This request is required to support commissioning and testing activities at the facility. On March 16, 2018, FERC approved the Citrus lateral and it was placed in service.

On September 21, 2016, intervenors filed an appeal of FERC's CPCN orders to the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court of Appeals). On August 22, 2017, the appeals court ruled against FERC in the case for failing to include enough information on the impact of greenhouse-gas emissions carried by the pipeline, vacated the CPCN order and remanded the case to FERC. In response to the August 2017 court decision, the FERC issued a draft Supplemental Environmental Impact Statement (SEIS) on September 27, 2017. On October 6, 2017, FERC and a group of industry intervenors, including Sabal Trail and Duke Energy Florida, filed separate petitions with the D.C. Circuit Court of Appeals requesting rehearing regarding the court's decision to vacate the CPCN order. On January 31, 2018, the D.C. Circuit Court of Appeals denied the requests for rehearing. On February 2, 2018, Sabal Trail filed a request with FERC for expedited issuance of its order on remand and reissuance of the CPCN. In the alternative, the pipeline requested that FERC issue a temporary emergency CPCN to allow for continued operations. On February 5, 2018, FERC issued the final SEIS. On February 6, 2018, FERC and the intervenors in this case each filed motions for stay with the D.C. Circuit Court to stay the court's mandate. On March 7, 2018, the D.C. Circuit Court of Appeals granted FERC and Sabal Trail's stay request. On March 14, 2018, FERC issued its final order on remand, which recertified the project. On August 10, 2018, FERC denied requests for rehearing of the final order on remand.

Constitution Pipeline Company, LLC

Duke Energy owns a 24 percent ownership interest in Constitution, which is accounted for as an equity method investment. Constitution is 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 will be constructed and operated by Williams Partners L.P., which has a 41 percent ownership share. The remaining interest is held by Cabot Oil and Gas Corporation and WGL Holdings, Inc. Before the permitting delays discussed below, Duke Energy's total anticipated contributions were approximately $229 million. As a result of the permitting delays and project uncertainty, total anticipated contributions by Duke Energy can no longer be reasonably estimated. Since April 2016, with the actions of the New York State Department of Environmental Conservation (NYSDEC), Constitution stopped construction and discontinued capitalization of future development costs until the project's uncertainty is resolved.

In December 2014, Constitution received approval from the FERC to construct and operate the proposed pipeline. However, on April 22, 2016, the NYSDEC denied Constitution's application for a necessary water quality certification for the New York portion of the Constitution pipeline. Constitution filed legal actions in the U.S. Court of Appeals for the Second Circuit (U.S. Court of Appeals) challenging the legality and appropriateness of the NYSDEC's decision and on August 18, 2017, the petition was denied in part and dismissed in part. In September 2017, Constitution filed a petition for a rehearing of portions of the decision unrelated to the water quality certification, which was denied by the U.S. Court of Appeals. In January 2018, Constitution petitioned the Supreme Court of the United States to review the U.S. Court of Appeals decision, and on April 30, 2018, the Supreme Court denied Constitution's petition. In October 2017, Constitution filed a petition for declaratory order requesting FERC to find that the NYSDEC waived its rights to issue a Section 401 water quality certification by not acting on Constitution's application within a reasonable period of time as required by statute. This petition was based on precedent established by another pipeline's successful petition with FERC following a District of Columbia Circuit Court ruling. On January 11, 2018, FERC denied Constitution's petition. In February 2018, Constitution filed a rehearing request with FERC of its finding that the NYSDEC did not waive the Section 401 certification requirement. On July 19, 2018, FERC denied Constitution's rehearing request. Constitution is currently unable to approximate an in-service date for the project due to the NYSDEC's denial of the water quality certification. The Constitution partners remain committed to the project and are evaluating next steps to move the project forward. On June 25, 2018, Constitution filed with FERC a Request for Extension of Time until December 2, 2020, for construction of the project. On November 5, 2018, FERC issued an Order Granting Extension of Time.

See Notes 12 and 17 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 primarily because facilities do not have the requisite emission control equipment to meet regulatory requirements expected to apply in the near future. 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 due to a lack of requisite environmental control equipment. Dollar amounts in the table below are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2018, 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**	**$**	**162**
Duke Energy Indiana			
Gallagher Units 2 and 4[(b)]	**280**		**121**
Total Duke Energy	**865**	**$**	**283**

(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.

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 $14.1 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 $13.6 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 99 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 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 each station 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, such as 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 percent of the available weekly limits for 52 weeks and 80 percent of the available weekly limits for the next 110 weeks. Coverage is provided until these available weekly periods are met where the accidental outage policy limit will not exceed $490 million for McGuire, Catawba and Harris, $476 million for Brunswick, $462 million for Oconee and $392 million for Robinson. NEIL sublimits the accidental outage recovery 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 $159 million, $97 million and $1 million, respectively. Duke Energy Carolinas' maximum assessment amount includes 100 percent 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 regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. These regulations 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 9, 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
Balance at December 31, 2015	$ 94	$ 10	$ 17	$ 3	$ 14	$ 54	$ 12
Provisions/adjustments	19	4	7	2	4	7	1
Cash reductions	(15)	(4)	(6)	(2)	(4)	(2)	(3)
Balance at December 31, 2016	98	10	18	3	14	59	10
Provisions/adjustments	8	3	3	2	2	3	(4)
Cash reductions	(25)	(3)	(6)	(2)	(4)	(15)	(1)
Balance at December 31, 2017	81	10	15	3	12	47	5
Provisions/adjustments	**26**	**3**	**2**	**3**	**(2)**	**21**	**1**
Cash reductions	**(30)**	**(2)**	**(6)**	**(2)**	**(4)**	**(20)**	**(1)**
Balance at December 31, 2018	**$ 77**	**$ 11**	**$ 11**	**$ 4**	**$ 6**	**$ 48**	**$ 5**

As of December 31, 2016, and October 31, 2016 and 2015, Piedmont's environmental reserve was $1 million. As of December 31, 2018, and 2017, the reserve was $2 million.

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	**$ 46**
Duke Energy Carolinas	**17**
Duke Energy Ohio	**19**
Piedmont	**2**

North Carolina and South Carolina Ash Basins

In February 2014, a break in a stormwater pipe beneath an ash basin at Duke Energy Carolinas' retired Dan River Steam Station caused a release of ash basin water and ash into the Dan River. In July 2014, Duke Energy completed remediation work identified by the EPA and continues to cooperate with the EPA's civil enforcement process. The NCDEQ has historically assessed Duke Energy Carolinas and Duke Energy Progress with NOVs for violations that were most often resolved through satisfactory corrective actions and minor, if any, fines or penalties. Subsequent to the Dan River ash release, Duke Energy Carolinas and Duke Energy Progress have been served with a higher level of NOVs, including assessed penalties for violations at Sutton and Dan River Steam Station. Duke Energy Carolinas and Duke Energy Progress continue to resolve violations through corrective actions, and associated penalties related to existing unresolved NOVs are not expected to be material.

LITIGATION

Duke Energy Carolinas and Duke Energy Progress

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. On January 23, 2019, the court granted the parties' joint motion for a four month stay of the proceedings, until June 3, 2019, to allow the parties to discuss potential resolution. If the case is not fully resolved at that time, litigation will resume. The trial remains scheduled for August 2020. 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 and the matter is proceeding before the trial court. No trial date has been scheduled. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter.

Federal Citizens Suits

On June 13, 2016, 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 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. The court has not yet ruled on these motions.

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, and the court has not yet ruled on these motions.

On May 8, 2018, on motion from Duke Energy Progress, the court ordered trial in both of the above matters to be consolidated. Trial is currently scheduled to begin July 15, 2019.

On June 20, 2017, RRBA filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina challenging the closure plans at the Mayo Plant under the EPA CCR Rule. Duke Energy Progress filed a motion to dismiss, which was granted by the court on March 30, 2018. RRBA had until April 30, 2018, to file an appeal to the Fourth Circuit but did not do so.

On August 2, 2017, RRBA filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina challenging the closure plans at the Roxboro Plant under the EPA CCR Rule. Duke Energy Progress filed a motion to dismiss on October 2, 2017, which was granted by the court on May 29, 2018. RRBA had until June 28, 2018, to file an appeal to the Fourth Circuit but did not do so.

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.

Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of these matters.

Groundwater Contamination Claims

Beginning in May 2015, a number of residents living in the vicinity of the North Carolina facilities with ash basins received letters from the NCDEQ advising them not to drink water from the private wells on their land tested by the NCDEQ as the samples were found to have certain substances at levels higher than the criteria set by the DHHS. Results of CSAs testing performed by Duke Energy under the Coal Ash Act have been consistent with historical data provided to state regulators over many years. The DHHS and NCDEQ sent follow-up letters on October 15, 2015, to residents near coal ash basins who have had their wells tested, stating that private well samplings at a considerable distance from coal ash basins, as well as some municipal water supplies, contain similar levels of vanadium and hexavalent chromium, which led investigators to believe these constituents are naturally occurring. In March 2016, DHHS rescinded the advisories.

Duke Energy Carolinas and Duke Energy Progress have received formal demand letters from residents near Duke Energy Carolinas' and Duke Energy Progress' coal ash basins. The residents claim damages for nuisance and diminution in property value, among other things. The parties held three days of mediation discussions, which ended at impasse. On January 6, 2017, Duke Energy Carolinas and Duke Energy Progress received the plaintiffs' notice of their intent to file suits should the matter not settle. The NCDEQ preliminarily approved Duke Energy's permanent water solution plans on January 13, 2017, and as a result shortly thereafter, Duke Energy issued a press release, providing additional details regarding the homeowner compensation package. This package consists of three components: (i) a $5,000 goodwill payment to each eligible well owner to support the transition to a new water supply, (ii) where a public water supply is available and selected by the eligible well owner, a stipend to cover 25 years of water bills and (iii) the Property Value Protection Plan. The Property Value Protection Plan is a program offered by Duke Energy designed to guarantee eligible plant neighbors the fair market value of their residential property should they decide to sell their property during the time that the plan is offered. Payments are being made and the remaining reserves are not material.

On August 23, 2017, a class-action suit was filed in Wake County Superior Court, North Carolina, against Duke Energy Carolinas and Duke Energy Progress on behalf of certain property owners living near coal ash impoundments at Allen, Asheville, Belews Creek, Buck, Cliffside, Lee, Marshall, Mayo and Roxboro. The class is defined as those who are well-eligible under the Coal Ash Act or those to whom Duke Energy has promised a permanent replacement water supply and seeks declaratory and injunctive relief, along with compensatory damages. Plaintiffs allege that Duke Energy's improper maintenance of coal ash impoundments caused harm, particularly through groundwater contamination. Despite NCDEQ's preliminary approval, Plaintiffs contend that Duke Energy's proposed permanent water solutions plan fails to comply with the Coal Ash Act. On September 28, 2017, Duke Energy Carolinas and Duke Energy Progress filed a Motion to Dismiss and Motion to Strike the class designation. The parties entered into a Settlement Agreement on January 24, 2018, which resulted in the dismissal of the underlying class action on January 25, 2018.

On September 14, 2017, a complaint was filed against Duke Energy Progress in New Hanover County Superior Court by a group of homeowners residing approximately 1 mile from Duke Energy Progress' Sutton Steam Plant. The homeowners allege that coal ash constituents have been migrating from ash impoundments at Sutton into their groundwater for decades and that in 2015, Duke Energy Progress discovered these releases of coal ash, but failed to notify any officials or neighbors and failed to take remedial action. The homeowners claim unspecified physical and mental injuries as a result of consuming their well water and seek actual damages for personal injury, medical monitoring and punitive damages. On March 6, 2018, Plaintiffs' counsel voluntarily dismissed the action without 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, 2018, there were 164 asserted claims for non-malignant cases with the cumulative relief sought of up to $42 million and 87 asserted claims for malignant cases with the cumulative relief sought of up to $21 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 $630 million and $489 million at December 31, 2018, and 2017, 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 2038 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 2038 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 $764 million in excess of the self-insured retention. Receivables for insurance recoveries were $739 million and $585 million at December 31, 2018, and 2017, 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 October 16, 2014, Duke Energy Progress and Duke Energy Florida sued the U.S. in the U.S. Court of Federal Claims. 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. Duke Energy Progress and Duke Energy Florida asserted damages for the period January 1, 2011, through December 31, 2013, of $48 million and $25 million, respectively. On November 17, 2017, the Court awarded Duke Energy Progress and Duke Energy Florida $48 million and $21 million, respectively, subject to appeal. No appeals were filed and Duke Energy Progress and Duke Energy Florida recognized the recoveries in the first quarter of 2018. Claims for all periods through 2013 have been resolved. On June 22, 2018, Duke Energy Progress and Duke Energy Florida filed a complaint for damages incurred for 2014 through first quarter 2018.

Duke Energy Progress

Gypsum Supply Agreements Matter

On June 30, 2017, CertainTeed filed a declaratory judgment action against Duke Energy Progress in the North Carolina Business Court relating to a gypsum supply agreement. In its complaint, CertainTeed sought an order from the court declaring that the minimum amount of gypsum Duke Energy Progress must provide to CertainTeed under the supply agreement was 50,000 tons per month through 2029. Trial in this matter was completed on July 16, 2018. On August 29, 2018, the court issued an order and opinion finding that Duke Energy Progress is required to supply 50,000 tons of gypsum/month, but that CertainTeed's sole remedy for Duke Energy Progress' long-term discontinuance under the agreement is liquidated damages. On November 14, 2018, the parties reached a settlement agreement. The amount owed under the liquidated damages provision is approximately $90 million on an undiscounted basis over 10 years. Approximately $3 million was paid in 2018. As of December 31, 2018, $9 million is recorded in Accounts payable within Current Liabilities and $63 million in Other within Other Noncurrent Liabilities on the Consolidated Balance Sheets. The liability is recorded on a discounted basis at a rate of approximately 4 percent. These costs are probable of recovery from customers and are recorded in Regulatory Assets within Other Noncurrent Assets on the Consolidated Balance Sheets.

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 combined-cycle 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 is attempting to recover from Fluor $110 million in additional costs incurred by Duke Energy Florida. Duke Energy Florida cannot predict the outcome of this matter. See Note 4 for additional information.

Class-Action Lawsuit

On February 22, 2016, a lawsuit was filed in the U.S. District Court for the Southern District of Florida on behalf of a class of Duke Energy Florida and FP&L's customers in Florida. The suit alleges the State of Florida's NCRS are unconstitutional and pre-empted by federal law. Plaintiffs claim they are entitled to repayment of all money paid by customers of Duke Energy Florida and FP&L as a result of the NCRS, as well as an injunction against any future charges under those statutes. The constitutionality of the NCRS has been challenged unsuccessfully in a number of prior cases on alternative grounds. Duke Energy Florida and FP&L filed motions to dismiss the complaint on May 5, 2016. On September 21, 2016, the Court granted the motions to dismiss with prejudice. Plaintiffs filed a motion for reconsideration, which was denied. On January 4, 2017, plaintiffs filed a notice of appeal to the Eleventh Circuit U.S. Court of Appeals (Eleventh Circuit). On July 11, 2018, the Eleventh Circuit affirmed the U.S. District Court's dismissal of the lawsuit. The deadline to file a petition for cert was October 9, 2018, and no petition was filed; therefore, the dismissal of the lawsuit is final.

Westinghouse Contract Litigation

On March 28, 2014, Duke Energy Florida filed a lawsuit against Westinghouse in the U.S. District Court for the Western District of North Carolina. The lawsuit seeks recovery of $54 million in milestone payments in excess of work performed under an EPC for Levy as well as a determination by the court of the amounts due to Westinghouse as a result of the termination of an EPC contract. Duke Energy Florida recognized an exit obligation as a result of the termination of the EPC. On March 31, 2014, Westinghouse filed a separate lawsuit against Duke Energy Florida in U.S. District Court for the Western District of Pennsylvania alleging damages under the same EPC contract in excess of $510 million for engineering and design work, costs to end supplier contracts and an alleged termination fee. On June 9, 2014, the judge in the North Carolina case ruled that the litigation will proceed in the Western District of North Carolina.

On July 11, 2016, Duke Energy Florida and Westinghouse filed separate Motions for Summary Judgment. On September 29, 2016, the court issued its ruling, granting Westinghouse a $30 million termination fee claim and dismissing Duke Energy Florida's $54 million refund claim. Westinghouse's claim for termination costs continued to trial. Following a trial on the matter, the court issued an order in December 2016 denying Westinghouse's claim for termination costs and reaffirming its earlier ruling in favor of Westinghouse on the $30 million termination fee. Judgment was entered against Duke Energy Florida in the amount of approximately $34 million, which includes prejudgment interest. Westinghouse appealed the trial court's order to the Fourth Circuit and Duke Energy Florida cross-appealed.

On March 29, 2017, Westinghouse filed Chapter 11 bankruptcy in the Southern District of New York, which automatically stayed the appeal. On May 23, 2017, the bankruptcy court entered an order lifting the stay with respect to the appeal. Westinghouse and Duke Energy Florida executed a settlement agreement resolving this matter on April 5, 2018. The bankruptcy court approved the settlement and Duke Energy Florida paid approximately $34 million to Westinghouse in July 2018 pursuant to this agreement. At the request of the parties, the Fourth Circuit has dismissed the appeal.

MGP Cost Recovery Action

On December 30, 2011, Duke Energy Florida filed a lawsuit against FirstEnergy to recover investigation and remediation costs incurred by Duke Energy Florida in connection with the restoration of two former MGP sites in Florida. Duke Energy Florida alleged that FirstEnergy, as the successor to Associated Gas & Electric Co., owes past and future contribution and response costs of up to $43 million for the investigation and remediation of MGP sites. On December 6, 2016, the trial court entered judgment against Duke Energy Florida in the case. In January 2017, Duke Energy Florida appealed the decision to the U.S. Court of Appeals for the Sixth Circuit, which affirmed the trial court's ruling on April 10, 2018. The dismissal of the lawsuit is therefore final.

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, the CertainTeed liquidated damages obligation and the exit obligation in 2017 related to the termination of an EPC contract. 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)	**2018**	**2017**
Reserves for Legal Matters		
Duke Energy	**$ 65**	$ 88
Duke Energy Carolinas	**9**	30
Progress Energy	**54**	55
Duke Energy Progress	**12**	13
Duke Energy Florida	**24**	24
Piedmont	**1**	2

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 unlimited maximum potential payments. However, the Duke Energy Registrants do not believe these guarantees will have a material effect on their results of operations, cash flows or financial position.

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, 2018						
(in millions)	**Contract Expiration**	**2019**	**2020**	**2021**	**2022**	**2023**	**Thereafter**	**Total**
Duke Energy Progress[a]	2022-2031	$ 51	$ 52	$ 53	$ 30	$ 25	$ 215	$ 426
Duke Energy Florida[b]	2021-2025	363	380	365	363	382	361	2,214
Duke Energy Ohio[c][d]	2020-2022	146	117	53	11	—	—	327

(a) Contracts represent 100 percent of net plant output.
(b) Contracts represent between 81 percent and 100 percent of net plant output.
(c) Contracts represent between 1 percent and 8 percent of net plant output.
(d) Excludes PPA with OVEC. See Note 17 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 16 years. The time periods for fixed payments under natural gas supply contracts are up to seven years. The time period for the natural gas supply purchase commitments is up to 12 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, 2018.

(in millions)	Duke Energy	Duke Energy Ohio	Piedmont
2019	$ 314	$ 38	$ 276
2020	287	30	257
2021	255	29	226
2022	225	11	214
2023	148	4	144
Thereafter	1,067	—	1,067
Total	$ 2,296	$ 112	$ 2,184

Operating and Capital Lease Commitments

The Duke Energy Registrants lease office buildings, railcars, vehicles and other property and equipment with various terms and expiration dates. Additionally, Duke Energy Carolinas and Duke Energy Progress have capital leases related to firm natural gas pipeline transportation capacity. Duke Energy Progress and Duke Energy Florida have entered into certain purchased power agreements, which are classified as leases. Consolidated capitalized lease obligations are classified as Long-Term Debt or Other within Current Liabilities on the Consolidated Balance Sheets. Amortization of assets recorded under capital leases is included in Depreciation and amortization and Fuel used in electric generation and purchased power on the Consolidated Statements of Operations.

The following tables present rental expense for operating leases. 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**	**2016**
Duke Energy	**$ 268**	$ 241	$ 242
Duke Energy Carolinas	**49**	44	45
Progress Energy	**143**	130	140
Duke Energy Progress	**75**	75	68
Duke Energy Florida	**68**	55	72
Duke Energy Ohio	**13**	15	16
Duke Energy Indiana	**21**	23	23

	Years Ended December 31,		Two Months Ended December 31,	Year Ended October 31,
(in millions)	**2018**	**2017**	**2016**	**2016**
Piedmont	**$ 11**	$ 7	$ 1	$ 5

The following table presents future minimum lease payments under operating leases, which at inception had a non-cancelable term of more than one year.

	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 future minimum lease payments under capital leases.

	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

6. DEBT AND CREDIT FACILITIES

Summary of Debt and Related Terms

The following tables summarize outstanding debt.

	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	—
Capital 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 capital lease purchase accounting adjustments related to Duke Energy Progress and Duke Energy Florida, respectively, related to power purchase agreements that are not accounted for as capital 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 program 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 17 for additional information on amounts from consolidated VIEs.

	December 31, 2017								
(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 2018-2073	4.17%	$ 20,409	$ 1,150	$ 3,950	$ —	$ 550	$ 900	$ 411	$ 2,050
Secured debt, maturing 2018-2037	3.15%	4,458	450	1,757	300	1,457	—	—	—
First mortgage bonds, maturing 2018-2047[(a)]	4.51%	23,529	7,959	11,801	6,776	5,025	1,100	2,669	—
Capital leases, maturing 2018-2051[(b)]	4.55%	1,000	61	269	139	129	5	11	—
Tax-exempt bonds, maturing 2019-2041[(c)]	3.23%	941	243	48	48	—	77	572	—
Notes payable and commercial paper[(d)]	1.57%	2,788	—	—	—	—	—	—	—
Money pool/intercompany borrowings		—	404	955	390	—	54	311	364
Fair value hedge carrying value adjustment		6	6	—	—	—	—	—	—
Unamortized debt discount and premium, net[(e)]		1,582	(19)	(30)	(16)	(10)	(33)	(9)	(1)
Unamortized debt issuance costs[(f)]		(271)	(47)	(108)	(40)	(56)	(7)	(21)	(12)
Total debt	4.09%	$ 54,442	$ 10,207	$ 18,642	$ 7,597	$ 7,095	$ 2,096	$ 3,944	$ 2,401
Short-term notes payable and commercial paper		(2,163)	—	—	—	—	—	—	—
Short-term money pool/intercompany borrowings		—	(104)	(805)	(240)	—	(29)	(161)	(364)
Current maturities of long-term debt[(g)]		(3,244)	(1,205)	(771)	(3)	(768)	(3)	(3)	(250)
Total long-term debt[(g)]		$ 49,035	$ 8,898	$ 17,066	$ 7,354	$ 6,327	$ 2,064	$ 3,780	$ 1,787

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.
(b) Duke Energy includes $81 million and $603 million of capital lease purchase accounting adjustments related to Duke Energy Progress and Duke Energy Florida, respectively, related to power purchase agreements that are not accounted for as capital 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 14 days.
(e) Duke Energy includes $1,509 million and $176 million purchase accounting adjustments related to the mergers with Progress Energy and Piedmont, respectively.
(f) Duke Energy includes $47 million in purchase accounting adjustments primarily related to the merger with Progress Energy.
(g) Refer to Note 17 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, 2018
Unsecured Debt			
Progress Energy	March 2019	7.050%	$ 450
Duke Energy (Parent)	September 2019	5.050%	500
Piedmont	September 2019	3.155% (b)	350
Duke Energy Kentucky	October 2019	4.65%	100
Progress Energy	December 2019	4.875%	350
First Mortgage Bonds			
Duke Energy Progress	January 2019	5.300%	600
Duke Energy Ohio	April 2019	5.450%	450
Other(a)			606
Current maturities of long-term debt			$ 3,406

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

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 and commercial paper and money pool borrowings for the Subsidiary Registrants.

	December 31, 2018							
(in millions)	Duke Energy(a)	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
2019	$ 3,408	$ 6	$ 1,674	$ 603	$ 270	552	$ 63	$ 350
2020	3,765	907	926	354	572	—	503	—
2021	4,803	503	2,004	904	600	50	70	160
2022	2,745	353	1,032	505	77	—	94	—
2023	3,375	1,303	535	456	79	350	153	45
Thereafter	35,288	7,940	12,880	5,437	5,793	1,251	2,925	1,595
Total long-term debt, including current maturities	$ 53,384	$ 11,012	$ 19,051	$ 8,259	$ 7,391	$ 2,203	$ 3,808	$ 2,150

(a) Excludes $1,578 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, 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**

	December 31, 2017				
(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

In January 2019, Duke Energy Ohio issued $800 million of first mortgage bonds. The issuance was split between a $400 million, 10-year tranche at 3.65 percent and a $400 million, 30-year tranche at 4.30 percent. The net proceeds will be used to refinance $450 million of Duke Energy Ohio bonds maturing in April 2019, to pay down short-term debt and for general corporate purposes.

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

			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.

			Year Ended December 31, 2017					
Issuance Date	Maturity Date	Interest Rate	Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio
Unsecured Debt								
April 2017[a]	April 2025	3.364%	$ 420	$ 420	$ —	$ —	$ —	$ —
June 2017[b]	June 2020	2.100%	330	330	—	—	—	—
August 2017[c]	August 2022	2.400%	500	500	—	—	—	—
August 2017[c]	August 2027	3.150%	750	750	—	—	—	—
August 2017[c]	August 2047	3.950%	500	500	—	—	—	—
December 2017[d]	December 2019 (k)	2.100%	400	—	—	—	400	—
Secured Debt								
February 2017[e]	June 2034	4.120%	587	—	—	—	—	—
August 2017[f]	December 2036	4.110%	233	—	—	—	—	—
First Mortgage Bonds								
January 2017[g]	January 2020	1.850%	250	—	—	—	250	—
January 2017[g]	January 2027	3.200%	650	—	—	—	650	—
March 2017[h]	June 2046	3.700%	100	—	—	—	—	100
September 2017[i]	September 2020	1.500% (l)	300	—	—	300	—	—
September 2017[i]	September 2047	3.600%	500	—	—	500	—	—
November 2017[j]	December 2047	3.700%	550	—	550	—	—	—
Total issuances			$ 6,070	$ 2,500	$ 550	$ 800	$ 1,300	$ 100

(a) Proceeds were used to refinance $400 million of unsecured debt at maturity and to repay a portion of outstanding commercial paper.
(b) Debt issued to repay a portion of outstanding commercial paper.
(c) Debt issued to repay at maturity $700 million of unsecured debt, to repay outstanding commercial paper and for general corporate purposes.
(d) Debt issued to fund storm restoration costs related to Hurricane Irma and for general corporate purposes.
(e) Portfolio financing of four Texas and Oklahoma wind facilities. Duke Energy pledged substantially all of the assets of these wind facilities and is nonrecourse to Duke Energy. Proceeds were used to reimburse Duke Energy for a portion of previously funded construction expenditures.
(f) Portfolio financing of eight solar facilities located in California, Colorado and New Mexico. Duke Energy pledged substantially all of the assets of these solar facilities and is nonrecourse to Duke Energy. Proceeds were used to reimburse Duke Energy for a portion of previously funded construction expenditures.
(g) Debt issued to fund capital expenditures for ongoing construction and capital maintenance, to repay a $250 million aggregate principal amount of bonds at maturity and for general corporate purposes.
(h) Proceeds were used to fund capital expenditures for ongoing construction, capital maintenance and for general corporate purposes.
(i) Debt issued to repay at maturity a $200 million aggregate principal amount of bonds at maturity, pay down intercompany short-term debt and for general corporate purposes, including capital expenditures.
(j) Debt issued to refinance $400 million aggregate principal amount of bonds due January 2018, pay down intercompany short-term debt and for general corporate purposes.
(k) Principal balance will be repaid in equal quarterly installments beginning in March 2018.
(l) Debt issuance has a floating interest rate.

Available Credit Facilities

In January 2018, Duke Energy extended the termination date of substantially all of its existing $8 billion Master Credit Facility capacity from March 16, 2022, to March 16, 2023. In May 2018, Duke Energy completed the extension process with 100 percent of all commitments to the Master Credit Facility extending to March 16, 2023. The Duke Energy Registrants, excluding Progress Energy (Parent), have borrowing capacity under the Master Credit Facility up to specified sublimits 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, 2018							
(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**	**$ 1,750**	**$ 1,400**	**$ 650**	**$ 450**	**$ 600**	**$ 500**
Reduction to backstop issuances								
Commercial paper[b]	**(3,022)**	**(917)**	**(739)**	**(444)**	**(108)**	**(299)**	**(317)**	**(198)**
Outstanding letters of credit	**(53)**	**(45)**	**(4)**	**(2)**	**—**	**—**	**—**	**(2)**
Tax-exempt bonds	**(81)**	**—**	**—**	**—**	**—**	**—**	**(81)**	**—**
Coal ash set-aside	**(500)**	**—**	**(250)**	**(250)**	**—**	**—**	**—**	**—**
Available capacity	**$ 4,344**	**$ 1,688**	**$ 757**	**$ 704**	**$ 542**	**$ 151**	**$ 202**	**$ 300**

(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 $1.0 billion revolving credit facility through June 2020. Borrowings under this facility will be used for general corporate purposes. As of December 31, 2018, $500 million has been drawn under the Three Year Revolver. 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 Three Year Revolver 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 will be used to pay storm-related costs, pay down commercial paper and to partially finance an upcoming bond maturity. As of December 31, 2018, $50 million has been drawn under the term loan. The balance is classified as Long-term debt on Duke Energy Progress' Consolidated Balance Sheets. In January and February 2019, the remaining $650 million was drawn under the term loan.

Piedmont Term Loan Facility

In September 2018, Piedmont executed an amendment to its existing senior unsecured term loan facility. The amendment increased commitments from $250 million to $350 million and extended the maturity date to September 2019. Borrowings under the facility will be used for general corporate purposes. As of December 31, 2018, the entire $350 million has been drawn under the Piedmont Term Loan. This balance is classified as Current maturities of long-term debt on Piedmont's Consolidated Balance Sheets. The terms and conditions of the Piedmont Term Loan are generally consistent with those governing Duke Energy's Master Credit Facility.

Other Debt Matters

In September 2016, 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 stock by Duke Energy.

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, 2018, and 2017 was $1,010 million and $986 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.

In January 2017, Duke Energy amended its Form S-3 to add Piedmont as a registrant and included in the amendment a prospectus for Piedmont under which it may issue debt securities in the same manner as other Duke Energy Registrants.

Money Pool

The Subsidiary Registrants, excluding Progress Energy (Parent), 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 (Parent), 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 percent for each borrower, excluding Piedmont, and 70 percent 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, 2018, 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, 2018, and 2017, Duke Energy had loans outstanding of $741 million, including $37 million at Duke Energy Progress and $701 million, including $38 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.

7. GUARANTEES AND INDEMNIFICATIONS

Duke Energy and Progress Energy have various financial and performance guarantees and indemnifications, which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, standby letters of credit, debt guarantees, surety bonds and indemnifications. Duke Energy and Progress Energy enter into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. At December 31, 2018, Duke Energy and Progress Energy do 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 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, 2018, the maximum potential amount of future payments associated with these guarantees was $205 million, the majority of which expires by 2028.

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 and less than wholly owned 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 the less than wholly owned entity. The maximum potential amount of future payments required under these guarantees as of December 31, 2018, was $296 million. Of this amount, $11 million relates to guarantees issued on behalf of less than wholly owned consolidated entities, with the remainder related to guarantees issued on behalf of third parties and unconsolidated affiliates of Duke Energy. Of the guarantees noted above, $248 million of the guarantees expire between 2019 and 2030, with the remaining performance guarantees having no contractual expiration.

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 $677 million as of December 31, 2018. This amount represents 47 percent of the outstanding borrowings under the credit facility.

Duke Energy guaranteed debt issued by Duke Energy Carolinas of $650 million as of December 31, 2018, and 2017.

Duke Energy has guaranteed certain issuers of surety bonds, obligating itself to make payment upon the failure of a wholly owned and former non-wholly owned entity to honor its obligations to a third party. Under these arrangements, Duke Energy has payment obligations that are triggered by a draw by the third party or customer due to the failure of the wholly owned or former non-wholly owned entity to perform according to the terms of its underlying contract. At December 31, 2018, Duke Energy had guaranteed $63 million of outstanding surety bonds, most of which have no set expiration.

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, 2018, Duke Energy had issued a total of $454 million in letters of credit, which expire between 2019 and 2022. The unused amount under these letters of credit was $60 million.

Duke Energy recognized $23 million and $21 million, as of December 31, 2018, and 2017, respectively, 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.

8. 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, 2018			
(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%**	**$ 989**	**$ 483**	**$ 17**
W.S. Lee CC[(b)]	**86.67%**	**593**	**12**	**4**
Duke Energy Indiana				
Gibson (unit 5)[(c)]	**50.05%**	**390**	**173**	**3**
Vermillion[(d)]	**62.50%**	**168**	**135**	**—**
Transmission and local facilities[(c)]	**Various**	**5,037**	**1,769**	**—**

(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 Indiana Municipal Power Agency.
(d) Jointly owned with WVPA.

Effective June 30, 2018, Duke Energy Ohio, Ohio Power Company, and The Dayton Power and Light Company, completed an asset exchange that reallocated their ownership interest in certain jointly owned transmission facilities. This transaction was approved by FERC and PUCO. The transaction eliminated the joint owner relationships for these assets. Assets were exchanged at net book value and the net increase in Duke Energy Ohio's assets are shown within Capital expenditures in Duke Energy Ohio's Consolidated Statements of Cash Flows.

9. 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, 2018							
(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]	$ 5,696	$ 2,335	$ 3,209	$ 2,679	$ 530	$ —	$ —	$ —
Closure of ash impoundments	4,446	1,568	2,123	2,103	20	52	702	—
Other[b]	325	46	79	38	41	41	20	19
Total asset retirement obligation	$ 10,467	$ 3,949	$ 5,411	$ 4,820	$ 591	$ 93	$ 722	$ 19
Less: current portion	919	290	514	509	5	6	109	—
Total noncurrent asset retirement obligation	$ 9,548	$ 3,659	$ 4,897	$ 4,311	$ 586	$ 87	$ 613	$ 19

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

(b) Primarily includes obligations related to asbestos removal. Duke Energy Ohio and Piedmont also include AROs related to the retirement of natural gas mains and services. Duke Energy includes AROs related to the removal of renewable energy generation assets.

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 dollars for Duke Energy Carolinas, 2017 dollars for Duke Energy Florida and 2014 dollars for Duke Energy Progress, 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	$ 8,737	2014 and 2018
Duke Energy Carolinas[b][c]	—	4,291	2018
Duke Energy Progress	24	3,550	2014
Duke Energy Florida[d]	—	896	2018

(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 is expected to be filed with the NCUC and PSCSC by the second quarter 2019. Duke Energy Carolinas will also complete a new funding study, which will be completed and filed with the NCUC and PSCSC in 2019.

(d) Duke Energy Florida's site-specific nuclear decommissioning cost study and a new funding study were completed and filed with the FPSC in 2018.

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 16 for additional information related to the fair value of the Duke Energy Registrants' NDTFs.

	December 31,	
(in millions)	**2018**	**2017**
Duke Energy	**$ 5,579**	$ 5,864
Duke Energy Carolinas	**3,133**	3,321
Duke Energy Progress	**2,446**	2,543

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 January 2018, Crystal River Unit 3 reached a SAFSTOR status.

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 either specific closure plans or the probability weightings of the potential closure methods as evaluated on a site-by-site basis. 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 2018 and 2017.

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, 2016	$ 10,611	$ 3,895	$ 5,475	$ 4,697	$ 778	$ 77	$ 866	$ 14
Accretion expense[a]	435	184	228	195	33	3	32	1
Liabilities settled[b]	(619)	(282)	(270)	(204)	(65)	(7)	(49)	(8)
Liabilities incurred in the current year[c]	51	5	—	—	—	7	29	8
Revisions in estimates of cash flows	(303)	(192)	(19)	(15)	(4)	4	(97)	—
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[d]	**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**

(a) Substantially all accretion expense for the years ended December 31, 2018, and 2017 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 groundwater monitoring estimates for closure of ash impoundments and an increase for nuclear decommissioning costs at Duke Energy Carolinas' nuclear sites compared to original estimates, partially offset by a reduction for nuclear decommissioning at Crystal River Unit 3 compared to original estimates and modifications to the timing of expected cash flows for coal ash AROs.

10. PROPERTY, PLANT AND EQUIPMENT

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

	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 capitalized 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 capitalized 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 capitalized 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.

	December 31, 2017								
(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		$ 1,559	$ 467	$ 767	$ 424	$ 343	$ 134	$ 111	$ 41
Plant – Regulated									
Electric generation, distribution and transmission	8-100	93,687	35,657	39,419	24,502	14,917	4,870	13,741	—
Natural gas transmission and distribution	12-80	8,292	—	—	—	—	2,559	—	5,733
Other buildings and improvements	15-100	1,936	647	652	316	336	243	240	154
Plant – Nonregulated									
Electric generation, distribution and transmission[(a)]	5-30	4,273	—	—	—	—	—	—	—
Other buildings and improvements	25-35	465	—	—	—	—	—	—	—
Nuclear fuel		3,680	2,120	1,560	1,560	—	—	—	—
Equipment	3-55	2,122	402	555	416	139	348	169	266
Construction in process		6,995	2,614	3,059	1,434	1,625	350	416	231
Other	3-40	4,498	1,032	1,311	931	370	228	271	300
Total property, plant and equipment[(b)(e)]		127,507	42,939	47,323	29,583	17,730	8,732	14,948	6,725
Total accumulated depreciation – regulated[(c)(d)(e)]		(39,742)	(15,063)	(15,857)	(10,903)	(4,947)	(2,691)	(4,662)	(1,479)
Total accumulated depreciation – nonregulated[(d)(e)]		(1,795)	—	—	—	—	—	—	—
Generation facilities to be retired, net		421	—	421	421	—	—	—	—
Total net property, plant and equipment		$ 86,391	$ 27,876	$ 31,887	$ 19,101	$ 12,783	$ 6,041	$ 10,286	$ 5,246

(a) Includes a pretax impairment charge of $58 million on a wholly owned non-contracted wind project. See discussion below.

(b) Includes capitalized leases of $1,294 million, $81 million, $272 million, $139 million, $133 million, $80 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 $114 million, $11 million and $103 million, respectively, of accumulated amortization of capitalized leases.

(c) Includes $2,113 million, $1,283 million, $831 million and $831 million of accumulated amortization of nuclear fuel at Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Progress, respectively.

(d) Includes accumulated amortization of capitalized leases of $57 million, $11 million, $21 million and $9 million at Duke Energy, Duke Energy Carolinas, Duke Energy Ohio and Duke Energy Indiana, respectively.

(e) Includes gross property, plant and equipment cost of consolidated VIEs of $3,941 million and accumulated depreciation of consolidated VIEs of $598 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; see Note 11 for additional information. 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)	**2018**	**2017**	**2016**
Duke Energy	**$ 161**	$ 128	$ 100
Duke Energy Carolinas	**35**	45	38
Progress Energy	**51**	45	31
Duke Energy Progress	**26**	21	17
Duke Energy Florida	**25**	24	14
Duke Energy Ohio	**17**	10	8
Duke Energy Indiana	**27**	9	7

	Years Ended December 31,		Two Months Ended December 31,	Year Ended October 31,
(in millions)	**2018**	**2017**	**2016**	**2016**
Piedmont	**$ 17**	$ 12	$ 2	$ 12

Operating Leases

Duke Energy's Commercial Renewables segment operates various renewable energy projects and sells the generated output to utilities, electric cooperatives, municipalities and commercial and industrial customers through long-term contracts. In certain situations, these long-term contracts and the associated renewable energy projects qualify as operating leases. Rental income from these leases is accounted for as Operating 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 $268 million, $262 million, and $216 million for the years ended December 31, 2018, 2017 and 2016. As of December 31, 2018, renewable energy projects owned by Duke Energy and accounted for as operating leases had a cost basis of $3,358 million and accumulated depreciation of $602 million. These assets are principally classified as nonregulated electric generation and transmission assets.

11. 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, 2018, and 2017.

(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total
Goodwill Balance at December 31, 2017	$ 17,379	$ 1,924	$ 122	$ 19,425
Accumulated impairment charges[(a)]	—	—	(29)	(29)
Goodwill balance at December 31, 2017, adjusted for accumulated impairment charges	$ 17,379	$ 1,924	$ 93	$ 19,396
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**

(a) Duke Energy evaluated the recoverability of goodwill during 2017 and recorded impairment charges of $29 million related to the Energy Management Solutions reporting unit within the Commercial Renewables segment. The fair value of the reporting unit was determined based on the market approach. See "Goodwill Impairment Testing" below for the results of the 2018 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, 2018, and 2017.

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.

In the third quarter of 2018, based on the results of the annual quantitative goodwill impairment test, management determined that the fair value of the Commercial Renewables reporting unit was below its respective carrying value, including goodwill. Determination of the Commercial Renewables reporting unit fair value was based on an income approach, which estimates the fair value based on discounted future cash flows. The fair value of the Commercial Renewables reporting unit is impacted by several factors, including forecasted tax credit utilization, the cost of capital, current and forecasted solar and wind volumes, and legislative developments. Certain assumptions used in determining the fair value of the reporting unit in the 2018 impairment test changed from those used in the 2017 annual impairment test including the cost of capital as a result of rising interest rates and the timing of tax credit utilization due to tax reform and IRS clarification on bonus depreciation in August 2018. Based on the quantitative impairment test, the estimated fair value of the Commercial Renewables reporting unit was below its carrying value by an immaterial amount but still more than the goodwill balance assigned to the reporting unit. As such, the entire remaining goodwill balance of approximately $93 million was impaired during the third quarter of 2018.

The fair value of all other reporting units for Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont exceeded their respective carrying values at the date of the annual impairment analysis.

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, 2018, and 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
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	$ —

	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
Emission allowances	$ 19	$ 1	$ 5	$ 2	$ 3	$ —	$ 13	$ —
Renewable energy certificates	148	38	107	107	—	3	—	—
Natural gas, coal and power contracts	24	—	—	—	—	—	24	—
Renewable operating and development projects	79	—	—	—	—	—	—	—
Other	6	—	—	—	—	—	—	3
Total gross carrying amounts	276	39	112	109	3	3	37	3
Accumulated amortization – natural gas, coal and power contracts	(19)	—	—	—	—	—	(19)	—
Accumulated amortization – renewable operating and development projects	(22)	—	—	—	—	—	—	—
Accumulated amortization – other	(5)	—	—	—	—	—	—	(3)
Total accumulated amortization	(46)	—	—	—	—	—	(19)	(3)
Total intangible assets, net	$ 230	$ 39	$ 112	$ 109	$ 3	$ 3	$ 18	$ —

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 that was recorded in 2007 when the project was acquired. Prior to the impairment, the gross amount of the intangible asset was $18 million and the accumulated amortization was $7 million. The intangible asset was fully impaired. See Note 10 for additional information.

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, 2018, 2017 and 2016, and are expected to be immaterial for the next five years as of December 31, 2018.

12. 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,					
	2018		2017		2016	
(in millions)	Investments	Equity in earnings	Investments	Equity in earnings	Investments	Equity in earnings
Electric Utilities and Infrastructure	**$ 97**	**$ 6**	$ 89	$ 5	$ 93	$ 5
Gas Utilities and Infrastructure	**1,003**	**27**	763	62	566	19
Commercial Renewables	**201**	**(1)**	190	(5)	185	(82)
Other	**108**	**51**	133	57	81	43
Total	**$ 1,409**	**$ 83**	$ 1,175	$ 119	$ 925	$ (15)

During the years ended December 31, 2018, 2017 and 2016, Duke Energy received distributions from equity investments of $108 million, $13 million and $31 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, 2018, and 2017, Duke Energy received distributions from equity investments of $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, 2018, and 2017, and the two months ended December 31, 2016, and the year ended October 31, 2016, Piedmont received distributions from equity investments of $1 million, $4 million, $1 million and $26 million, respectively, which are included in Other assets within Cash Flows from Operating Activities and $3 million, $2 million, $1 million and $18 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 percent 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.

		Investment Amount (in millions)	
Entity Name	**Ownership Interest**	**December 31, 2018**	**December 31, 2017**
Pipeline Investments			
Atlantic Coast Pipeline, LLC[a]	47%	**$ 797**	$ 397
Sabal Trail Transmission, LLC	7.5%	**112** (d)	219
Constitution Pipeline, LLC[a]	24%	**25**	81
Cardinal Pipeline Company, LLC[b]	21.49%	**10**	11
Storage Facilities			
Pine Needle LNG Company, LLC[b]	45%	**13**	13
Hardy Storage Company, LLC[b]	50%	**46**	42
Total Investments[c]		**$ 1,003**	$ 763

(a) During the year ended December 31, 2017, Piedmont transferred its share of ownership interest in ACP and Constitution to a wholly owned subsidiary of Duke Energy at book value.
(b) Piedmont owns the Cardinal, Pine Needle and Hardy Storage investments.
(c) Duke Energy includes purchase accounting adjustments related to Piedmont.
(d) 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 7 for additional information. As a result of the financing, ACP returned capital of $265 million to Duke Energy.

Piedmont sold its 15 percent membership interest in SouthStar on October 3, 2016, for $160 million resulting in an after tax gain of $81 million during the year ended October 31, 2016. Piedmont's Equity in Earnings in SouthStar was $19 million for the year ended October 31, 2016.

During the fourth quarter of 2018, 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 17.

Commercial Renewables

Duke Energy has a 50 percent interest in DS Cornerstone, LLC, which owns wind farm projects in the U.S.

Impairment of Equity Method Investments

During the year ended December 31, 2018, Duke Energy recorded an OTTI of the Constitution investment of $55 million within Equity in earnings of unconsolidated affiliates on Duke Energy's Consolidated Statements of Operations. 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 recent actions taken by the courts and regulators to uphold the NYSDEC's denial of the certification and uncertainty associated with the remaining legal and regulatory challenges. For additional information on the Constitution investment, see Note 4.

During the year ended December 31, 2016, Duke Energy recorded an OTTI of certain wind project investments. The $71 million pretax impairment was recorded within Equity in earnings (losses) of unconsolidated affiliates on Duke Energy's Consolidated Statements of Operations. The other-than-temporary decline in value of these investments was primarily attributable to a sustained decline in market pricing where the wind investments are located, projected net losses for the projects and a reduction in the projected cash distribution to the class of investment owned by Duke Energy.

Other

Duke Energy owns a 17.5 percent 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 percent with the successful startup of NMC's polyacetal production facility in 2017. Duke Energy retains 25 percent of the board representation and voting rights of NMC.

13. 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)	**2018**	**2017**	**2016**
Duke Energy Carolinas			
Corporate governance and shared service expenses[a]	**$ 985**	$ 858	$ 831
Indemnification coverages[b]	**22**	23	22
JDA revenue[c]	**84**	49	38
JDA expense[c]	**207**	145	156
Intercompany natural gas purchases[d]	**15**	9	2
Progress Energy			
Corporate governance and shared service expenses[a]	**$ 906**	$ 736	$ 710
Indemnification coverages[b]	**34**	38	35
JDA revenue[c]	**207**	145	156
JDA expense[c]	**84**	49	38
Intercompany natural gas purchases[d]	**78**	77	19
Duke Energy Progress			
Corporate governance and shared service expenses[a]	**$ 577**	$ 438	$ 397
Indemnification coverages[b]	**13**	15	14
JDA revenue[c]	**207**	145	156
JDA expense[c]	**84**	49	38
Intercompany natural gas purchases[d]	**78**	77	19
Duke Energy Florida			
Corporate governance and shared service expenses[a]	**$ 329**	$ 298	$ 313
Indemnification coverages[b]	**21**	23	21
Duke Energy Ohio			
Corporate governance and shared service expenses[a]	**$ 374**	$ 363	$ 356
Indemnification coverages[b]	**5**	5	5
Duke Energy Indiana			
Corporate governance and shared service expenses[a]	**$ 405**	$ 370	$ 366
Indemnification coverages[b]	**7**	8	8
Piedmont			
Corporate governance and shared service expenses[a]	**$ 170**	$ 50	
Indemnification coverages[b]	**2**	2	
Intercompany natural gas sales[d]	**93**	86	
Natural gas storage and transportation costs[e]	**25**	25	

(e) 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.

(f) 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.

(g) 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.

(h) 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. For the two months ended December 31, 2016, and for sales made subsequent to the acquisition for the year ended October 31, 2016, Piedmont recorded $14 million and $7 million, respectively, of natural gas sales with Duke Energy. For sales made prior to the acquisition for the year ended October 31, 2016, Piedmont recorded $74 million of natural gas sales with Duke Energy.

(i) 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. For the two months ended December 31, 2016, and for the year ended October 31, 2016, Piedmont recorded $6 million and $29 million, respectively, of natural gas storage and transportation costs.

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 6 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 17, 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, 2018							
Intercompany income tax receivable	**$ 52**	**$ 47**	**$ 29**	**$ —**	**$ —**	**$ 8**	**$ —**
Intercompany income tax payable	**—**	**—**	**—**	**16**	**3**	**—**	**45**
December 31, 2017							
Intercompany income tax receivable	$ —	$ 168	$ —	$ 44	$ 22	$ —	$ 7
Intercompany income tax payable	44	—	21	—	—	35	—

14. 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 swaps 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, 2018, 2017 and 2016 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.

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.

In August 2016, Duke Energy unwound $1.4 billion of forward-starting interest rate swaps associated with the Piedmont acquisition financing. The swaps were considered undesignated as they did not qualify for hedge accounting. Losses on the swaps of $190 million are included within Interest Expense on the Consolidated Statements of Operations for the year ended December 31, 2016. See Note 2 for additional information related to the Piedmont acquisition.

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

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

	December 31, 2017					
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**
Cash flow hedges[(a)]	$ 660	$ —	$ —	$ —	$ —	$ —
Undesignated contracts	927	400	500	250	250	27
Total notional amount	$ 1,587	$ 400	$ 500	$ 250	$ 250	$ 27

(a) Duke Energy includes amounts related to consolidated VIEs of $422 million in cash flow hedges and $194 million in undesignated contracts as of December 31, 2018, and $660 million in cash flow hedges as of December 31, 2017.

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, 2018							
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Electricity (gigawatt-hours)	**15,286**	**—**	**—**	**—**	**—**	**1,786**	**13,500**	**—**
Natural gas (millions of dekatherms)	**739**	**121**	**169**	**166**	**3**	**—**	**1**	**448**

	December 31, 2017						
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana	Piedmont
Electricity (gigawatt-hours)	34	—	—	—	—	34	—
Natural gas (millions of dekatherms)	770	105	183	133	50	2	480

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, 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

Derivative Assets	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
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 34	$ 2	$ 2	$ 1	$ 1	$ 1	$ 27	$ 2
Noncurrent	1	—	1	1	—	—	—	—
Total Derivative Assets – Commodity Contracts	$ 35	$ 2	$ 3	$ 2	$ 1	$ 1	$ 27	$ 2
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 1	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	15	—	—	—	—	—	—	—
Total Derivative Assets – Interest Rate Contracts	$ 16	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Total Derivative Assets	$ 51	$ 2	$ 3	$ 2	$ 1	$ 1	$ 27	$ 2

Derivative Liabilities	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
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 36	$ 6	$ 18	$ 8	$ 10	$ —	$ —	$ 11
Noncurrent	146	4	10	4	—	—	—	131
Total Derivative Liabilities – Commodity Contracts	$ 182	$ 10	$ 28	$ 12	$ 10	$ —	$ —	$ 142
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 29	$ 25	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	6	—	—	—	—	—	—	—
Not Designated as Hedging Instruments								
Current	1	—	1	—	—	1	—	—
Noncurrent	12	—	7	6	2	4	—	—
Total Derivative Liabilities – Interest Rate Contracts	$ 48	$ 25	$ 8	$ 6	$ 2	$ 5	$ —	$ —
Total Derivative Liabilities	$ 230	$ 35	$ 36	$ 18	$ 12	$ 5	$ —	$ 142

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, 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

Derivative Assets	**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								
Gross amounts recognized	$ 35	$ 2	$ 2	$ 1	$ 1	$ 1	$ 27	$ 2
Gross amounts offset	—	—	—	—	—	—	—	—
Net amounts presented in Current Assets: Other	$ 35	$ 2	$ 2	$ 1	$ 1	$ 1	$ 27	$ 2
Noncurrent								
Gross amounts recognized	$ 16	$ —	$ 1	$ 1	$ —	$ —	$ —	$ —
Gross amounts offset	—	—	—	—	—	—	—	—
Net amounts presented in Other Noncurrent Assets: Other	$ 16	$ —	$ 1	$ 1	$ —	$ —	$ —	$ —

Derivative Liabilities	**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								
Gross amounts recognized	$ 66	$ 31	$ 19	$ 8	$ 10	$ 1	$ —	$ 11
Gross amounts offset	(3)	(2)	(2)	(2)	—	—	—	—
Net amounts presented in Current Liabilities: Other	$ 63	$ 29	$ 17	$ 6	$ 10	$ 1	$ —	$ 11
Noncurrent								
Gross amounts recognized	$ 164	$ 4	$ 17	$ 10	$ 2	$ 4	$ —	$ 131
Gross amounts offset	(1)	—	(1)	(1)	—	—	—	—
Net amounts presented in Other Noncurrent Liabilities: Other	$ 163	$ 4	$ 16	$ 9	$ 2	$ 4	$ —	$ 131

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, 2018				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**
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**	**—**

	December 31, 2017				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**
Aggregate fair value of derivatives in a net liability position	$ 59	$ 35	$ 25	$ 15	$ 10
Fair value of collateral already posted	—	—	—	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	59	35	25	15	10

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.

15. 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 NDTF and 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, 2018, and 2017.

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, 2018			December 31, 2017		
(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	$ —	$ —	$ 88	$ —	$ —	$ 115
Equity securities	2,402	95	4,475	2,805	27	4,914
Corporate debt securities	4	13	566	17	2	570
Municipal bonds	1	4	353	4	3	344
U.S. government bonds	14	12	1,076	11	7	1,027
Other debt securities	—	2	148	—	1	118
Total NDTF Investments	$ 2,421	$ 126	$ 6,706	$ 2,837	$ 40	$ 7,088
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 22	$ —	$ —	$ 15
Equity securities	36	1	99	59	—	123
Corporate debt securities	—	2	60	1	—	57
Municipal bonds	—	1	85	2	1	83
U.S. government bonds	1	—	45	—	—	41
Other debt securities	—	1	58	—	1	44
Total Other Investments	$ 37	$ 5	$ 369	$ 62	$ 2	$ 363
Total Investments	$ 2,458	$ 131	$ 7,075	$ 2,899	$ 42	$ 7,451

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2018
Due in one year or less	$ 98
Due after one through five years	501
Due after five through 10 years	570
Due after 10 years	1,222
Total	$ 2,391

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, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were as follows.

	Year Ended December 31,
(in millions)	**2018**
FV-NI:	
Realized gains	**$ 168**
Realized losses	**126**
AFS:	
Realized gains	**22**
Realized losses	**51**

	Years Ended December 31,	
(in millions)	2017	2016
Realized gains	$ 202	$ 246
Realized losses	160	187

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, 2018			December 31, 2017		
(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	**$ —**	**$ —**	**$ 29**	$ —	$ —	$ 32
Equity securities	**1,309**	**54**	**2,484**	1,531	12	2,692
Corporate debt securities	**2**	**9**	**341**	9	2	359
Municipal bonds	**—**	**1**	**81**	—	1	60
U.S. government bonds	**5**	**8**	**475**	3	4	503
Other debt securities	**—**	**2**	**143**	—	1	112
Total NDTF Investments	**$ 1,316**	**$ 74**	**$ 3,553**	$ 1,543	$ 20	$ 3,758

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2018**
Due in one year or less	**$ 6**
Due after one through five years	**142**
Due after five through 10 years	**303**
Due after 10 years	**589**
Total	**$ 1,040**

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, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were as follows.

	Year Ended December 31,
(in millions)	**2018**
FV-NI:	
Realized gains	**$ 89**
Realized losses	**73**
AFS:	
Realized gains	**19**
Realized losses	**35**

	Years Ended December 31,	
(in millions)	2017	2016
Realized gains	$ 135	$ 157
Realized losses	103	121

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, 2018			December 31, 2017		
(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	$ —	$ —	$ 59	$ —	$ —	$ 83
Equity securities	1,093	41	1,991	1,274	15	2,222
Corporate debt securities	2	4	225	8	—	211
Municipal bonds	1	3	272	4	2	284
U.S. government bonds	9	4	601	8	3	524
Other debt securities	—	—	5	—	—	6
Total NDTF Investments	$ 1,105	$ 52	$ 3,153	$ 1,294	$ 20	$ 3,330
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 17	$ —	$ —	$ 12
Municipal bonds	—	—	47	2	—	47
Total Other Investments	$ —	$ —	$ 64	$ 2	$ —	$ 59
Total Investments	$ 1,105	$ 52	$ 3,217	$ 1,296	$ 20	$ 3,389

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2018
Due in one year or less	$ 87
Due after one through five years	306
Due after five through 10 years	216
Due after 10 years	541
Total	$ 1,150

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, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were as follows.

(in millions)	Year Ended December 31, 2018
FV-NI:	
Realized gains	**$ 79**
Realized losses	**53**
AFS:	
Realized gains	**3**
Realized losses	**15**

(in millions)	Years Ended December 31, 2017	2016
Realized gains	$ 65	$ 84
Realized losses	56	64

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, 2018			December 31, 2017		
(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	**$ —**	**$ —**	**$ 46**	$ —	$ —	$ 50
Equity securities	**833**	**30**	**1,588**	980	12	1,795
Corporate debt securities	**2**	**3**	**171**	6	—	149
Municipal bonds	**1**	**3**	**271**	4	2	283
U.S. government bonds	**6**	**3**	**415**	5	2	310
Other debt securities	**—**	**—**	**3**	—	—	4
Total NDTF Investments	**$ 842**	**$ 39**	**$ 2,494**	$ 995	$ 16	$ 2,591
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 6**	$ —	$ —	$ 1
Total Other Investments	**$ —**	**$ —**	**$ 6**	$ —	$ —	$ 1
Total Investments	**$ 842**	**$ 39**	**$ 2,500**	$ 995	$ 16	$ 2,592

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2018**
Due in one year or less	**$ 49**
Due after one through five years	**231**
Due after five through 10 years	**161**
Due after 10 years	**419**
Total	**$ 860**

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, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were as follows.

	Year Ended December 31,
(in millions)	**2018**
FV-NI:	
Realized gains	**$ 68**
Realized losses	**48**
AFS:	
Realized gains	**$ 2**
Realized losses	**10**

	Years Ended December 31,	
(in millions)	2017	2016
Realized gains	$ 54	$ 71
Realized losses	48	55

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, 2018			December 31, 2017		
(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	$ —	$ —	$ 13	$ —	$ —	$ 33
Equity securities	260	11	403	294	3	427
Corporate debt securities	—	1	54	2	—	62
Municipal bonds	—	—	1	—	—	1
U.S. government bonds	3	1	186	3	1	214
Other debt securities	—	—	2	—	—	2
Total NDTF Investments[(a)]	$ 263	$ 13	$ 659	$ 299	$ 4	$ 739
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 1	$ —	$ —	$ 1
Municipal bonds	—	—	47	2	—	47
Total Other Investments	$ —	$ —	$ 48	$ 2	$ —	$ 48
Total Investments	$ 263	$ 13	$ 707	$ 301	$ 4	$ 787

(a) During the year ended December 31, 2018, Duke Energy Florida continued to receive reimbursements from the NDTF for costs related to ongoing decommissioning activity of the Crystal River Unit 3 nuclear plant.

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2018**
Due in one year or less	$ 38
Due after one through five years	75
Due after five through 10 years	55
Due after 10 years	122
Total	$ 290

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, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were as follows.

	Year Ended December 31,
(in millions)	**2018**
FV-NI:	
Realized gains	$ 11
Realized losses	5

AFS:	
Realized gains	**1**
Realized losses	**5**

	Years Ended December 31,	
(in millions)	2017	2016
Realized gains	$ 11	$ 13
Realized losses	8	9

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, 2018			**December 31, 2017**		
(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	**$ 29**	**$ —**	**$ 67**	$ 49	$ —	$ 97
Corporate debt securities	**—**	**—**	**8**	—	—	3
Municipal bonds	**—**	**1**	**33**	—	1	28
Total Investments	**$ 29**	**$ 1**	**$ 108**	$ 49	$ 1	$ 128

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2018**
Due in one year or less	**$ 3**
Due after one through five years	**20**
Due after five through 10 years	**4**
Due after 10 years	**14**
Total	**$ 41**

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, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were insignificant.

16. 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 NAV 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.

Transfers between levels represent assets or liabilities that were previously (i) categorized at a higher level for which the inputs to the estimate became less observable or (ii) classified at a lower level for which the inputs became more observable during the period. The Duke Energy Registrant's policy is to recognize transfers between levels of the fair value hierarchy at the end of the period. There were no transfers between levels during the years ended December 31, 2018, 2017 and 2016. In addition, for Piedmont, there were no transfers between levels during the two months ended December 31, 2016, and the year ended October 31, 2016.

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 the 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. Other commodity derivatives, including Piedmont's natural gas supply contracts, are primarily valued using internally developed discounted cash flow models that incorporate forward price, adjustments for liquidity (bid-ask spread) and credit or non-performance risk (after reflecting credit enhancements such as collateral), and are discounted to present value. Pricing inputs are derived from published exchange transaction prices and other observable data sources. In the absence of an active market, the last available price may be used. 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 11 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 14. See Note 15 for additional information related to investments by major security type for the Duke Energy Registrants.

	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**

	December 31, 2017				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
NDTF equity securities	$ 4,914	$ 4,840	$ —	$ —	$ 74
NDTF debt securities	2,174	635	1,539	—	—
Other equity securities	123	123	—	—	—
Other debt securities	241	57	184	—	—
Derivative assets	51	3	20	28	—
Total assets	7,503	5,658	1,743	28	74
Derivative liabilities	(230)	(2)	(86)	(142)	—
Net assets (liabilities)	$ 7,273	$ 5,656	$ 1,657	$ (114)	$ 74

The following tables provide reconciliations of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements. Amounts included in earnings for derivatives are primarily included in Cost of natural gas on the Duke Energy Registrants' Consolidated Statements of Operations and Comprehensive Income. Amounts included in changes of net assets on the Duke Energy Registrants' Consolidated Balance Sheets are included in regulatory assets or liabilities. All derivative assets and liabilities are presented on a net basis.

	December 31, 2018	December 31, 2017		
(in millions)	**Derivatives (net)**	**Investments**	**Derivatives (net)**	**Total**
Balance at beginning of period	**$ (114)**	$ 5	$ (166)	$ (161)
Total pretax realized or unrealized gains included in comprehensive income	**—**	1	—	1
Purchases, sales, issuances and settlements:				
Purchases	**57**	—	55	55
Sales	**—**	(6)	—	(6)
Settlements	**(57)**	—	(47)	(47)
Total gains included on the Consolidated Balance Sheet	**1**	—	44	44
Balance at end of period	**$ (113)**	$ —	$ (114)	$ (114)

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, 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**

	December 31, 2017			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Not Categorized**
NDTF equity securities	$ 2,692	$ 2,618	$ —	$ 74
NDTF debt securities	1,066	204	862	—
Derivative assets	2	—	2	—
Total assets	3,760	2,822	864	74
Derivative liabilities	(35)	(1)	(34)	—
Net assets	$ 3,725	$ 2,821	$ 830	$ 74

The following table provides reconciliations of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements.

	Investments	
	Year Ended December 31,	
(in millions)		2017
Balance at beginning of period	$	3
Total pretax realized or unrealized gains included in comprehensive income		1
Purchases, sales, issuances and settlements:		
Sales		(4)
Balance at end of period	$	—

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, 2018			December 31, 2017		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF equity securities	**$ 1,991**	**$ 1,991**	**$ —**	$ 2,222	$ 2,222	$ —
NDTF debt securities	**1,162**	**427**	**735**	1,108	431	677
Other debt securities	**64**	**17**	**47**	59	12	47
Derivative assets	**4**	**—**	**4**	3	1	2
Total assets	**3,221**	**2,435**	**786**	3,392	2,666	726
Derivative liabilities	**(44)**	**—**	**(44)**	(36)	(1)	(35)
Net assets	**$ 3,177**	**$ 2,435**	**$ 742**	$ 3,356	$ 2,665	$ 691

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, 2018			December 31, 2017		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF equity securities	**$ 1,588**	**$ 1,588**	**$ —**	$ 1,795	$ 1,795	$ —
NDTF debt securities	**906**	**294**	**612**	796	243	553
Other debt securities	**6**	**6**	**—**	1	1	—
Derivative assets	**4**	**—**	**4**	2	1	1
Total assets	**2,504**	**1,888**	**616**	2,594	2,040	554
Derivative liabilities	**(27)**	**—**	**(27)**	(18)	(1)	(17)
Net assets	**$ 2,477**	**$ 1,888**	**$ 589**	$ 2,576	$ 2,039	$ 537

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, 2018			December 31, 2017		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF equity securities	$ 403	$ 403	$ —	$ 427	$ 427	$ —
NDTF debt securities	256	133	123	312	188	124
Other debt securities	48	1	47	48	1	47
Derivative assets	—	—	—	1	—	1
Total assets	707	537	170	788	616	172
Derivative liabilities	(9)	—	(9)	(12)	—	(12)
Net assets	$ 698	$ 537	$ 161	$ 776	$ 616	$ 160

DUKE ENERGY OHIO

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, 2018			December 31, 2017		
(in millions)	Total Fair Value	Level 2	Level 3	Total Fair Value	Level 2	Level 3
Derivative assets	$ 6	$ —	$ 6	$ 1	$ —	$ 1
Derivative liabilities	(5)	(5)	—	(5)	(5)	—
Net assets (liabilities)	$ 1	$ (5)	$ 6	$ (4)	$ (5)	$ 1

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)	2018	2017
Balance at beginning of period	$ 1	$ 5
Purchases, sales, issuances and settlements:		
Purchases	7	3
Settlements	(4)	(4)
Total gains included on the Consolidated Balance Sheet	2	(3)
Balance at end of period	$ 6	$ 1

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, 2018				December 31, 2017			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**
Other equity securities	**$ 67**	**$ 67**	**$ —**	**$ —**	$ 97	$ 97	$ —	$ —
Other debt securities	**41**	**—**	**41**	**—**	31	—	31	—
Derivative assets	**23**	**1**	**—**	**22**	27	—	—	27
Total assets	**$ 131**	**$ 68**	**$ 41**	**$ 22**	$ 155	$ 97	$ 31	$ 27

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)	**2018**	**2017**
Balance at beginning of period	**$ 27**	$ 16
Purchases, sales, issuances and settlements:		
Purchases	**50**	52
Settlements	**(53)**	(43)
Total (losses) gains included on the Consolidated Balance Sheet	**(2)**	2
Balance at end of period	**$ 22**	$ 27

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, 2018			December 31, 2017		
(in millions)	**Total Fair Value**	**Level 1**	**Level 3**	**Total Fair Value**	**Level 1**	**Level 3**
Other debt securities	**$ —**	**$ —**	**$ —**	$ 1	$ 1	$ —
Derivative assets	**3**	**3**	**—**	2	2	—
Total assets	**3**	**3**	**—**	3	3	—
Derivative liabilities	**(141)**	**—**	**(141)**	(142)	—	(142)
Net (liabilities) assets	**$ (138)**	**$ 3**	**$ (141)**	$ (139)	$ 3	$ (142)

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)	2018	2017
Balance at beginning of period	$ (142)	$ (187)
Total gains and settlements	1	45
Balance at end of period	$ (141)	$ (142)

QUANTITATIVE INFORMATION ABOUT UNOBSERVABLE INPUTS

The following tables include quantitative information about the Duke Energy Registrants' derivatives classified as Level 3.

	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)			

	December 31, 2017			
Investment Type	Fair Value (in millions)	Valuation Technique	Unobservable Input	Range
Duke Energy Ohio				
FTRs	$ 1	RTO auction pricing	FTR price – per MWh	$ 0.07 – $ 1.41
Duke Energy Indiana				
FTRs	27	RTO auction pricing	FTR price – per MWh	(0.77) – 7.44
Piedmont				
Natural gas contracts	(142)	Discounted cash flow	Forward natural gas curves — price per MMBtu	2.10 – 2.88
Duke Energy				
Total Level 3 derivatives	$ (114)			

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, 2018		December 31, 2017	
(in millions)	Book Value	Fair Value	Book Value	Fair Value
Duke Energy[a]	**$ 54,529**	**$ 54,534**	$ 52,279	$ 55,331
Duke Energy Carolinas	**10,939**	**11,471**	10,103	11,372
Progress Energy	**18,911**	**19,885**	17,837	20,000
Duke Energy Progress	**8,204**	**8,300**	7,357	7,992
Duke Energy Florida	**7,321**	**7,742**	7,095	7,953
Duke Energy Ohio	**2,165**	**2,239**	2,067	2,249
Duke Energy Indiana	**3,782**	**4,158**	3,783	4,464
Piedmont	**2,138**	**2,180**	2,037	2,209

(a) Book value of long-term debt includes $1.6 billion as of December 31, 2018, and $1.7 billion as of December 31, 2017, 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, 2018, and December 31, 2017, 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.

17. 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 these 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, 2018, 2017 and 2016, 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 limited liability companies 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.

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 percent cash and 25 percent 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 are not performed 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 outlines amounts and expiration dates of the credit facilities described above.

	Duke Energy	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida
	CRC	DERF	DEPR	DEFR
Expiration date	December 2020	December 2020	February 2021	April 2021
Credit facility amount (in millions)	$ 325	$ 450	$ 300	$ 225
Amounts borrowed at December 31, 2018	325	450	300	225
Amounts borrowed at December 31, 2017	325	450	300	225
Restricted Receivables at December 31, 2018	564	699	547	357
Restricted Receivables at December 31, 2017	545	640	459	317

Nuclear Asset-Recovery Bonds – 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. For additional information see Notes 4 and 6.

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.

(in millions)	December 31, 2018	December 31, 2017
Receivables of VIEs	**$ 5**	$ 4
Regulatory Assets: Current	**52**	51
Current Assets: Other	**39**	40
Other Noncurrent Assets: Regulatory assets	**1,041**	1,091
Current Liabilities: Other	**10**	10
Current maturities of long-term debt	**53**	53
Long-Term Debt	**1,111**	1,164

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 solar energy systems 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 renewables VIEs.

(in millions)	December 31, 2018	December 31, 2017
Current Assets: Other	**$ 123**	$ 174
Property, plant and equipment, cost	**4,007**	3,923
Accumulated depreciation and amortization	**(698)**	(591)
Other Noncurrent Assets: Other	**261**	50
Current maturities of long-term debt	**174**	170
Long-Term Debt	**1,587**	1,700
Other Noncurrent Liabilities: Deferred income taxes	**—**	(148)
Other Noncurrent Liabilities: Asset Retirement Obligations	**106**	83
Other Noncurrent Liabilities: Other	**212**	241

NON-CONSOLIDATED VIEs

The following tables summarize the impact of non-consolidated VIEs on the Consolidated Balance Sheets.

	December 31, 2018					
	Duke Energy				Duke	Duke
	Pipeline	Commercial	Other		Energy	Energy
(in millions)	Investments	Renewables	VIEs	Total	Ohio	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

	December 31, 2017					
	Duke Energy				Duke	Duke
	Pipeline	Commercial	Other		Energy	Energy
(in millions)	Investments	Renewables	VIEs	Total	Ohio	Indiana
Receivables from affiliated companies	$ —	$ —	$ —	$ —	$ 87	$ 106
Investments in equity method unconsolidated affiliates	697	180	42	919	—	—
Other noncurrent assets	17	—	—	17	—	—
Total assets	$ 714	$ 180	$ 42	$ 936	$ 87	$ 106
Taxes accrued	(29)	—	—	(29)	—	—
Other current liabilities	—	—	4	4	—	—
Deferred income taxes	42	—	—	42	—	—
Other noncurrent liabilities	—	—	12	12	—	—
Total liabilities	$ 13	$ —	$ 16	$ 29	$ —	$ —
Net assets	$ 701	$ 180	$ 26	$ 907	$ 87	$ 106

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 power purchase agreement 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 $677 million as of December 31, 2018. For more information on various guarantees, refer to Note 7.

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.

The table below presents Duke Energy's ownership interest and investment balance in these joint ventures.

		Investment Amount (in millions)	
Entity Name	Ownership Interest	December 31, 2018	December 31, 2017
ACP	47%	**$ 797**	$ 397
Sabal Trail[(a)]	7.5%	**—**	219
Constitution[(b)]	24%	**25**	81
Total		**$ 822**	$ 697

(a) At December 31, 2017, Sabal Trail was considered a VIE due to having insufficient equity to finance their own activities without subordinated financial support. However, Sabal Trail is now a fully operational, well capitalized entity. As a result, Sabal Trail has sufficient equity to finance its own activities, and therefore, is no longer considered a VIE. Duke Energy's investment in Sabal Trail was $112 million at December 31, 2018.

(b) During the year ended December 31, 2018, Duke Energy recorded an OTTI of $55 million related to Constitution within Equity in earnings of unconsolidated affiliates on Duke Energy's Consolidated Statements of Income. See Note 4 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.

Pioneer

Duke Energy holds a 50 percent equity interest in Pioneer. Pioneer is considered a VIE due to having insufficient equity to finance their own activities without subordinated financial support. The activities that most significantly impact Pioneer's economic performance are decisions related to the development of new transmission facilities. The power to direct these activities is jointly and equally shared by Duke Energy and the other joint venture partner, American Electric Power; therefore, Duke Energy does not consolidate Pioneer.

OVEC

Duke Energy Ohio’s 9 percent ownership interest in OVEC is considered a non-consolidated VIE due to 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 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 and an ICPA counterparty with a power participation ratio of 4.85 percent, 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 percent and a 20 percent 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	
	2018	**2017**	**2018**	**2017**
Anticipated credit loss ratio	**0.5%**	0.5%	**0.3%**	0.3%
Discount rate	**3.0%**	2.1%	**3.0%**	2.1%
Receivable turnover rate	**13.5%**	13.5%	**11.0%**	10.7%

The following table shows the gross and net receivables sold.

	Duke Energy Ohio		Duke Energy Indiana	
(in millions)	**2018**	**2017**	**2018**	**2017**
Receivables sold	**$ 269**	$ 273	**$ 336**	$ 312
Less: Retained interests	**93**	87	**118**	106
Net receivables sold	**$ 176**	$ 186	**$ 218**	$ 206

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)	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Sales						
Receivables sold	**$ 1,987**	$ 1,879	$ 1,926	**$ 2,842**	$ 2,711	$ 2,635
Loss recognized on sale	**13**	10	9	**16**	12	11
Cash Flows						
Cash proceeds from receivables sold	**1,967**	1,865	1,882	**2,815**	2,694	2,583
Collection fees received	**1**	1	1	**1**	1	1
Return received on retained interests	**6**	3	2	**9**	7	5

Cash flows from the 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 percent.

18. REVENUE

As described in Note 1, Duke Energy adopted Revenue from Contracts with Customers effective January 1, 2018, using the modified retrospective method of adoption, which does not require restatement of prior year reported results. No cumulative effect adjustment was recorded as the vast majority of Duke Energy's revenues are at-will and without a defined contractual term. Additionally, comparative disclosures for 2018 operating results with the previous revenue recognition rules are not applicable as Duke Energy's revenue recognition has not materially changed as a result of the new standard.

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)	**2019**	**2020**	**2021**	**2022**	**2023**	**Thereafter**	**Total**
Progress Energy	$ 112	$ 121	$ 80	$ 82	$ 39	$ 42	$ 476
Duke Energy Progress	9	9	9	9	9	9	54
Duke Energy Florida	103	112	71	73	30	33	422
Duke Energy Indiana	9	10	5	—	—	—	24

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)	**2019**	**2020**	**2021**	**2022**	**2023**	**Thereafter**	**Total**
Piedmont	$ 70	$ 68	$ 63	$ 63	$ 60	$ 430	$ 754

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:

	Year Ended December 31, 2018							
(in millions) **By market or type of customer**	**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 and Ohio 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 and Tennessee 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)	**2018**	**2017**
Duke Energy	**$ 896**	$ 944
Duke Energy Carolinas	**313**	342
Progress Energy	**244**	228
Duke Energy Progress	**148**	143
Duke Energy Florida	**96**	85
Duke Energy Ohio	**2**	4
Duke Energy Indiana	**23**	21
Piedmont	**73**	86

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 accounts 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 17 for further information. These receivables for unbilled revenues are shown in the table below.

	December 31,	
(in millions)	**2018**	**2017**
Duke Energy Ohio	**$ 86**	$ 104
Duke Energy Indiana	**128**	132

19. COMMON STOCK

Basic EPS is computed by dividing net income attributable 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 attributable 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 shares, such as stock options and equity forward sale agreements, were exercised or settled. Duke Energy's participating securities are restricted stock units that are entitled to dividends declared on Duke Energy common stock during the restricted stock unit's vesting periods.

The following table presents Duke Energy's basic and diluted EPS calculations and reconciles the weighted average number of common stock outstanding to the diluted weighted average number of common stock outstanding.

	Years Ended December 31,		
(in millions, except per share amounts)	**2018**	**2017**	**2016**
Income from continuing operations attributable to Duke Energy common stockholders excluding impact of participating securities	**$ 2,642**	$ 3,059	$ 2,567
Weighted average shares outstanding – basic	**708**	700	691
Weighted average shares outstanding – diluted	**708**	700	691
Earnings per share from continuing operations attributable to Duke Energy common stockholders			
Basic	**$ 3.73**	$ 4.37	$ 3.71
Diluted	**$ 3.73**	$ 4.37	$ 3.71
Potentially dilutive items excluded from the calculation[(a)]	**2**	2	2
Dividends declared per common share	**$ 3.64**	$ 3.49	$ 3.36

(a) Performance stock awards were not included in the dilutive securities calculation because the performance measures related to the awards had not been met.

Equity Issuances

On February 20, 2018, Duke Energy filed a prospectus supplement and executed an 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. The EDA was entered into with Wells Fargo Securities, LLC, Citigroup Global Markets Inc., and J.P. Morgan Securities LLC (the Agents). Under the terms of the EDA, Duke Energy may issue and sell, through any of the Agents, shares of common stock during the period ending September 23, 2019. In June 2018, Duke Energy marketed two separate tranches, each for 1.3 million shares, of common stock. The first tranche was marketed with Wells Fargo Bank at an initial forward price of $72.02 per share and the second tranche was marketed with Citibank at an initial forward price of $78.71 per share through equity forward transactions under the ATM program. The Equity Forwards require Duke Energy to either physically settle the transactions by issuing 2.6 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. The settlement alternative was at Duke Energy's election. 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.

Separately, in March 2018, Duke Energy marketed an equity offering of 21.3 million shares of common stock through an Underwriting Agreement with Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Barclays Capital Inc. and Goldman Sachs & Co. LLC, as representatives of several underwriters, Credit Suisse Capital LLC and J.P. Morgan Securities LLC as Forward Sellers, and Credit Suisse Capital LLC and J.P. Morgan Chase Bank, National Association, acting as forward purchasers. In connection with the offering, Duke Energy entered into equity forward sale agreements with Credit Suisse Securities (USA) LLC as Agent for Credit Suisse Capital LLC and J.P. Morgan Chase Bank, National Association. The sale price was $75 per share less certain net adjustments for an initial forward price of $74.07 per share. The Equity Forwards require 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. The settlement alternative was at Duke Energy's election. 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.

For the year ended December 31, 2018, Duke Energy issued 2.2 million shares through its DRIP with an increase in additional paid-in capital of approximately $174 million.

In March 2016, Duke Energy marketed an equity offering of 10.6 million shares of common stock. In lieu of issuing equity at the time of the offering, Duke Energy entered into Equity Forwards with Barclays. The Equity Forwards required Duke Energy to either physically settle the transactions by issuing 10.6 million shares, or net settle in whole or in part through the delivery or receipt of cash or shares. On October 5, 2016, following the close of the Piedmont acquisition, Duke Energy physically settled the Equity Forwards in full by delivering 10.6 million shares of common stock in exchange for net cash proceeds of approximately $723 million. The net proceeds were used to finance a portion of the Piedmont acquisition. As a result of the acquisition, all of Piedmont's issued and outstanding stock became the issued and outstanding shares of a wholly owned subsidiary of Duke Energy. See Note 2 for additional information related to the Piedmont acquisition.

20. 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 is 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.

During 2016, Duke Energy and Piedmont announced severance plans covering certain eligible employees whose employment will be involuntarily terminated without cause as a result of Duke Energy's acquisition of Piedmont. These reductions continued into 2017 and were a part of the synergies expected to be realized with the acquisition. Refer to Note 2 for additional information on the Piedmont acquisition.

Severance benefit charges for initiatives and plans discussed above were accrued for a total of approximately 1,900 employees in 2018, 100 employees in 2017 and 600 employees in 2016. The following table presents the direct and allocated severance and related charges recorded by the Duke Energy Registrants. Amounts are included 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[(a)]
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
Year Ended December 31, 2016	118	39	40	23	17	3	7	

(a) Piedmont severance benefit charges were $3 million for the two months ended December 31, 2016, and $19 million for the year ended October 31, 2016.

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, 2017	$ 19	$ 5	$ 2	$ 1	$ —	$ —	$ —	$ 5
Provision/Adjustments	**200**	**98**	**50**	**40**	**10**	**2**	**2**	**—**
Cash Reductions	**(14)**	**(3)**	**(1)**	**—**	**(1)**	**—**	**—**	**(5)**
Balance at December 31, 2018	**$ 205**	**$ 100**	**$ 51**	**$ 41**	**$ 9**	**$ 2**	**$ 2**	**$ —**

21. STOCK-BASED COMPENSATION

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)	2018	2017	2016
Duke Energy	**$ 56**	$ 43	$ 35
Duke Energy Carolinas	**20**	15	12
Progress Energy	**21**	16	12
Duke Energy Progress	**13**	10	7
Duke Energy Florida	**8**	6	5
Duke Energy Ohio	**4**	3	2
Duke Energy Indiana	**5**	4	3
Piedmont[(a)]	**3**	3	

(a) Piedmont's stock-based compensation costs were not material for the two months ended December 31, 2016. See discussion below for information on Piedmont's pre-merger stock-based compensation plans.

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)	2018	2017	2016
Restricted stock unit awards	**$ 43**	$ 41	$ 36
Performance awards	**35**	27	19
Pretax stock-based compensation cost	**$ 78**	$ 68	$ 55
Stock-based compensation costs capitalized	**5**	4	2
Stock-based compensation expense	**$ 73**	$ 64	$ 53
Tax benefit associated with stock-based compensation expense	**$ 17**	$ 25	$ 20

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,		
	2018	**2017**	**2016**
Shares awarded (in thousands)	**649**	583	684
Fair value (in millions)	**$ 49**	$ 47	$ 52

The following table summarizes information about RSU awards outstanding.

	Shares (in thousands)	**Weighted Average Grant Date Fair Value (per share)**
Outstanding at December 31, 2017	1,121	$ 78
Granted	**649**	**76**
Vested	**(545)**	**78**
Forfeited	**(72)**	**77**
Outstanding at December 31, 2018	**1,153**	**77**
Restricted stock unit awards expected to vest	**1,101**	**77**

The total grant date fair value of shares vested during the years ended December 31, 2018, 2017 and 2016, was $43 million, $42 million and $38 million, respectively. At December 31, 2018, Duke Energy had $29 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of 23 months.

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 percent of target shares, depending on the level of performance achieved.

Performance awards contain market conditions based on relative TSR compared to a predefined peer group, as well as a performance condition based on Duke Energy's cumulative adjusted EPS. Performance awards granted in 2018 and 2017 also contain a performance condition based on the total incident case rate, one of our key employee safety metrics.

The market condition component of Duke Energy's performance awards 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 2018, the model used a risk-free interest rate of 2.4 percent, which reflects the yield on three-year Treasury bonds as of the grant date, and an expected volatility of 16.0 percent 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,		
	2018	**2017**	**2016**
Shares granted assuming target performance (in thousands)	**372**	461	338
Fair value (in millions)	**$ 27**	$ 37	$ 25

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, 2017	1,065	$ 79
Granted	**372**	**73**
Vested	**(155)**	**81**
Forfeited	**(165)**	**80**
Outstanding at December 31, 2018	**1,117**	**77**
Stock-based performance awards expected to vest	**1,086**	**77**

The total grant date fair value of shares vested during the years ended December 31, 2018, and 2016, was $13 million and $25 million, respectively. No performance awards vested during the year ended December 31, 2017. At December 31, 2018, Duke Energy had $30 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of 21 months.

PIEDMONT

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 Merger Agreement provided for the conversion of the 2014-2016 and 2015-2017 performance awards and the nonvested 2016 RSU award into the right to receive $60 cash per share upon the close of the transaction. In December 2015, Piedmont's board of directors authorized the accelerated vesting, payment and taxation of the 2014-2016 and 2015-2017 performance awards, as well as the 2016 RSU award, at the election of the participant. Substantially all participants elected to accelerate the settlement of these awards. As a result of the settlement of these awards, 194 thousand shares of Piedmont shares were issued to participants, net of shares withheld for applicable federal and state income taxes, at a closing price of $56.85 and a fair value of $11 million. The 2016-2018 performance award cycle was approved subsequent to the Merger Agreement and was converted into a Duke Energy RSU award at the consummation of the acquisition.

Piedmont's stock-based compensation costs and the tax benefit associated with stock-based compensation expense are included in the following table.

(in millions)	Year Ended October 31, 2016
Pretax stock-based compensation cost	$ 16
Tax benefit associated with stock-based compensation expense	6
Net of tax stock-based compensation cost	$ 10

22. 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.

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. These allocated amounts are included in the governance and shared service costs discussed in Note 13.

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 2019. The following table includes information related to the Duke Energy Registrants’ contributions to its qualified defined benefit pension plans.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont[(a)]
Contributions Made:								
2018	**$ 141**	**$ 46**	**$ 45**	**$ 25**	**$ 20**	**$ —**	**$ 8**	**$ —**
2017	19	—	—	—	—	4	—	11
2016	155	43	43	24	20	5	9	

(a) Piedmont contributed $10 million to its U.S. qualified defined benefit pension plan during the two months ended December 31, 2016, and $10 million for the year ended October 31, 2016.

QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	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

	Year Ended December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Service cost	$ 147	$ 48	$ 42	$ 24	$ 19	$ 4	$ 9
Interest cost on projected benefit obligation	335	86	106	49	55	19	28
Expected return on plan assets	(519)	(142)	(168)	(82)	(84)	(27)	(42)
Amortization of actuarial loss	134	33	51	23	29	4	11
Amortization of prior service credit	(17)	(8)	(3)	(2)	(1)	—	(1)
Settlement charge	3	—	—	—	—	—	—
Other	8	2	3	1	1	1	1
Net periodic pension costs(a)(b)	$ 91	$ 19	$ 31	$ 13	$ 19	$ 1	$ 6

(a) Duke Energy amounts exclude $5 million, $7 million and $8 million for the years ended December 2018, 2017 and 2016, 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, $3 million and $4 million for the years ended December 2018, 2017 and 2016, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

	Piedmont	
	Two Months Ended	**Year Ended**
(in millions)	**December 31, 2016**	**October 31, 2016**
Service cost	$ 2	$ 11
Interest cost on projected benefit obligation	2	9
Expected return on plan assets	(4)	(24)
Amortization of actuarial loss	2	8
Amortization of prior service credit	(1)	(2)
Settlement charge	3	—
Net periodic pension costs	$ 4	$ 2

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets

	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)	**$ 298**	**$ 170**	**$ 40**	**$ 31**	**$ 9**	**$ 10**	**$ 30**	**$ 8**
Accumulated other comprehensive loss (income)								
Deferred income tax expense	**$ (2)**	**—**	**1**	**—**	**—**	**—**	**—**	**—**
Amortization of prior year service credit	**1**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Amortization of prior year actuarial losses	**10**	**—**	**(4)**	**—**	**—**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive income	**$ 9**	**$ —**	**$ (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**
Regulatory assets, net (decrease) increase	$ (212)	$ (70)	$ (49)	$ (37)	$ (11)	$ 9	$ (19)	$ (64)
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ —	$ —	$ 3	$ —	$ —	$ —	$ —	$ —
Prior year service credit arising during the year	1	—	—	—	—	—	—	—
Amortization of prior year actuarial losses	(7)	—	(7)	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ (6)	$ —	$ (4)	$ —	$ —	$ —	$ —	$ —

Piedmont's regulatory asset net increase was $34 million and $35 million for the two months ended December 31, 2016, and for the year ended October 31, 2016, respectively.

Reconciliation of Funded Status to Net Amount Recognized

	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

	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**
Change in Projected Benefit Obligation								
Obligation at prior measurement date	$ 8,131	$ 1,952	$ 2,512	$ 1,158	$ 1,323	$ 447	$ 658	$ 344
Service cost	159	48	45	26	19	4	9	10
Interest cost	328	79	100	47	53	18	26	14
Actuarial loss	455	68	158	57	99	35	26	38
Transfers	—	27	(32)	(2)	(15)	12	—	—
Plan amendments	(61)	—	—	—	—	—	—	(61)
Benefits paid	(537)	(145)	(146)	(75)	(69)	(37)	(50)	(5)
Benefits paid — settlements	(27)	—	—	—	—	—	—	(27)
Obligation at measurement date	$ 8,448	$ 2,029	$ 2,637	$ 1,211	$ 1,410	$ 479	$ 669	$ 313
Accumulated Benefit Obligation at measurement date	$ 8,369	$ 2,029	$ 2,601	$ 1,211	$ 1,375	$ 468	$ 652	$ 313
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 8,531	$ 2,225	$ 2,675	$ 1,290	$ 1,352	$ 428	$ 657	$ 346
Employer contributions	19	—	—	—	—	4	—	11
Actual return on plan assets	1,017	265	317	153	161	51	77	43
Benefits paid	(537)	(145)	(146)	(75)	(69)	(37)	(50)	(5)
Benefits paid — settlements	(27)	—	—	—	—	—	—	(27)
Transfers	—	27	(32)	(2)	(15)	12	—	—
Plan assets at measurement date	$ 9,003	$ 2,372	$ 2,814	$ 1,366	$ 1,429	$ 458	$ 684	$ 368
Funded status of plan	$ 555	$ 343	$ 177	$ 155	$ 19	$ (21)	$ 15	$ 55

Amounts Recognized in the Consolidated Balance Sheets

	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 (liability) 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)

	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
Prefunded pension[(a)]	$ 680	$ 343	$ 245	$ 155	$ 87	$ 8	$ 16	$ 55
Noncurrent pension liability[(b)]	$ 125	$ —	$ 68	$ —	$ 68	$ 29	$ 1	$ —
Net asset recognized	$ 555	$ 343	$ 177	$ 155	$ 19	$ (21)	$ 15	$ 55
Regulatory assets	$ 1,886	$ 406	$ 756	$ 341	$ 415	$ 90	$ 152	$ 73
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (41)	$ —	$ (3)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(5)	—	—	—	—	—	—	—
Net actuarial loss	116	—	9	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 70	$ —	$ 6	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension costs in the next year								
Unrecognized net actuarial loss	$ 132	$ 29	$ 44	$ 21	$ 23	$ 5	$ 7	$ 11
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, 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**

	December 31, 2017			
(in millions)	**Duke Energy**	**Progress Energy**	**Duke Energy Florida**	**Duke Energy Ohio**
Projected benefit obligation	$ 1,386	$ 718	$ 718	$ 337
Accumulated benefit obligation	1,326	683	683	326
Fair value of plan assets	1,260	650	650	308

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 13 years for Duke Energy and Duke Energy Progress, 12 years for Duke Energy Carolinas, Progress Energy, and Duke Energy Florida, 14 years for Duke Energy Ohio and Duke Energy Indiana, and 10 years for Piedmont.

The following tables present the assumptions or range of assumptions used for pension benefit accounting.

	December 31,		
	2018	**2017**	**2016**
Benefit Obligations			
Discount rate	**4.30%**	3.60%	4.10%
Salary increase	**3.50% – 4.00%**	3.50% – 4.00%	4.00% – 4.50%
Net Periodic Benefit Cost			
Discount rate	**3.60%**	4.10%	4.40%
Salary increase	**3.50% – 4.00%**	4.00% – 4.50%	4.00% – 4.40%
Expected long-term rate of return on plan assets	**6.50%**	6.50% – 6.75%	6.50% – 6.75%

	Piedmont	
	Two Months Ended December 31, 2016	**Year Ended October 31, 2016**
Benefit Obligations		
Discount rate	4.10%	3.80%
Salary increase	4.50%	4.05%
Net Periodic Benefit Cost		
Discount rate	3.80%	4.34%
Salary increase	4.05%	4.07%
Expected long-term rate of return on plan assets	6.75%	7.25%

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,								
2019	$ 662	$ 210	$ 179	$ 105	$ 73	$ 33	$ 47	$ 20
2020	651	177	171	90	80	37	51	24
2021	663	182	177	95	81	37	51	23
2022	662	189	179	94	84	37	49	22
2023	655	185	181	95	85	35	47	22
2024-2028	2,993	794	902	451	447	158	217	96

NON-QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	Year Ended December 31, 2018				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**
Service cost	$ 2	$ 1	$ —	$ —	$ —
Interest cost on projected benefit obligation	12	—	4	1	2
Amortization of actuarial loss	8	—	2	1	1
Amortization of prior service credit	(2)	—	—	—	—
Net periodic pension costs	$ 20	$ 1	$ 6	$ 2	$ 3

	Year Ended December 31, 2017				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**
Service cost	$ 2	$ 1	$ —	$ —	$ —
Interest cost on projected benefit obligation	13	1	5	1	2
Amortization of actuarial loss	8	—	2	1	1
Amortization of prior service credit	(2)	—	—	—	—
Net periodic pension costs	$ 21	$ 2	$ 7	$ 2	$ 3

	Year Ended December 31, 2016				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**
Service cost	$ 2	$ —	$ —	$ —	$ —
Interest cost on projected benefit obligation	14	1	5	1	2
Amortization of actuarial loss	8	1	1	1	1
Amortization of prior service credit	(1)	—	—	—	—
Net periodic pension costs	$ 23	$ 2	$ 6	$ 2	$ 3

	Piedmont
	Year Ended
(in millions)	**October 31, 2016**
Amortization of prior service cost	$ —
Settlement charge	1
Net periodic pension costs	$ 1

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets and Liabilities

	Year Ended December 31, 2018				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**
Regulatory assets, net (decrease) increase	**$ (16)**	**$ 1**	**$ (6)**	**$ (3)**	**$ (3)**
Accumulated other comprehensive (income) loss					
Deferred income tax benefit	**$ 1**	**$ —**	**$ 1**	**$ —**	**$ —**
Actuarial gain arising during the year	**(4)**	**—**	**(3)**	**—**	**—**
Net amount recognized in accumulated other comprehensive loss (income)	**$ (3)**	**$ —**	**$ (2)**	**$ —**	**$ —**

	Year Ended December 31, 2017				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**
Regulatory assets, net increase (decrease)	$ 5	$ (1)	$ 3	$ 1	$ 2
Accumulated other comprehensive (income) loss					
Prior service credit arising during the year	$ (1)	$ —	$ —	$ —	$ —
Actuarial loss arising during the year	2	—	—	—	—
Net amount recognized in accumulated other comprehensive loss (income)	$ 1	$ —	$ —	$ —	$ —

Reconciliation of Funded Status to Net Amount Recognized

(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, 2018							
Change in Projected Benefit Obligation								
Obligation at prior measurement date	**$ 331**	**$ 14**	**$ 116**	**$ 35**	**$ 47**	**$ 4**	**$ 3**	**$ 4**
Service cost	**2**	**1**	**—**	**—**	**—**	**—**	**—**	**—**
Interest cost	**12**	**—**	**4**	**1**	**2**	**—**	**—**	**—**
Actuarial gain	**(17)**	**—**	**(6)**	**(2)**	**(3)**	**(1)**	**—**	**(1)**
Benefits paid	**(24)**	**(1)**	**(8)**	**(3)**	**(3)**	**—**	**—**	**—**
Obligation at measurement date	**$ 304**	**$ 14**	**$ 106**	**$ 31**	**$ 43**	**$ 3**	**$ 3**	**$ 3**
Accumulated Benefit Obligation at measurement date	**$ 304**	**$ 14**	**$ 106**	**$ 31**	**$ 43**	**$ 3**	**$ 3**	**$ 3**
Change in Fair Value of Plan Assets								
Benefits paid	**$ (24)**	**$ (1)**	**$ (8)**	**$ (3)**	**$ (3)**	**$ —**	**$ —**	**$ —**
Employer contributions	**24**	**1**	**8**	**3**	**3**	**—**	**—**	**—**
Plan assets at measurement date	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

(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, 2017							
Change in Projected Benefit Obligation								
Obligation at prior measurement date	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3	$ 4
Service cost	2	1	—	—	—	—	—	—
Interest cost	13	1	5	1	2	—	—	—
Actuarial loss (gain)	15	—	5	4	2	—	—	—
Benefits paid	(31)	(2)	(8)	(3)	(3)	—	—	—
Obligation at measurement date	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Accumulated Benefit Obligation at measurement date	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Change in Fair Value of Plan Assets								
Benefits paid	$ (31)	$ (2)	$ (8)	$ (3)	$ (3)	$ —	$ —	$ —
Employer contributions	31	2	8	3	3	—	—	—
Plan assets at measurement date	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Amounts Recognized in the Consolidated Balance Sheets

	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 pension liability[a]	$ 21	$ 2	$ 8	$ 3	$ 3	$ —	$ —	$ —
Noncurrent pension liability[b]	283	12	98	28	40	3	3	3
Total accrued pension liability	$ 304	$ 14	$ 106	$ 31	$ 43	$ 3	$ 3	$ 3
Regulatory assets	$ 62	$ 5	$ 15	$ 5	$ 10	$ 1	$ —	$ 1
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (3)	$ —	$ (2)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(1)	—	—	—	—	—	—	—
Net actuarial loss	8	—	6	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 4	$ —	$ 4	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	$ 6	$ —	$ 2	$ 1	$ 1	$ —	$ —	$ —
Unrecognized prior service credit	(2)	—	—	—	—	—	—	—

	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 pension liability[a]	$ 23	$ 2	$ 8	$ 3	$ 3	$ —	$ —	$ —
Noncurrent pension liability[b]	308	12	108	32	44	4	3	4
Total accrued pension liability	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Regulatory assets	$ 78	$ 4	$ 21	$ 8	$ 13	$ 1	$ —	$ 1
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (4)	$ —	$ (3)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(1)	—	—	—	—	—	—	—
Net actuarial loss	12	—	9	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 7	$ —	$ 6	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	$ 8	$ —	$ 2	$ 1	$ 1	$ —	$ —	$ —
Unrecognized prior service credit	$ (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.

Information for Plans with Accumulated Benefit Obligation in Excess of Plan 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**
Projected benefit obligation	**$ 304**	**$ 14**	**$ 106**	**$ 31**	**$ 43**	**$ 3**	**$ 3**	**$ 3**
Accumulated benefit obligation	**304**	**14**	**106**	**31**	**43**	**3**	**3**	**3**

	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**
Projected benefit obligation	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Accumulated benefit obligation	331	14	116	35	47	4	3	4

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 of active covered employees is 10 years for Duke Energy, 13 years for Progress Energy, 11 years for Duke Energy Progress, 15 years for Duke Energy Florida, eight years for Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Piedmont. The following tables present the assumptions used for pension benefit accounting.

	December 31,		
	2018	**2017**	**2016**
Benefit Obligations			
Discount rate	**4.30%**	3.60%	4.10%
Salary increase	**3.50% – 4.00%**	3.50% – 4.00%	4.40%
Net Periodic Benefit Cost			
Discount rate	**3.60%**	4.10%	4.40%
Salary increase	**3.50% – 4.00%**	4.40%	4.40%

	Piedmont	
	Two Months Ended December 31, 2016	**Year Ended October 31, 2016**
Benefit Obligations		
Discount rate	4.10%	3.80%
Net Periodic Benefit Cost		
Discount rate	3.80%	3.85%

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,								
2019	$ 22	$ 2	$ 8	$ 3	$ 3	$ —	$ —	$ —
2020	21	1	8	2	3	—	—	—
2021	23	1	8	2	3	—	—	—
2022	25	1	8	2	3	—	—	—
2023	25	3	7	2	3	—	—	—
2024-2028	125	10	37	11	15	1	1	2

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, 2018, 2017 or 2016.

Components of Net Periodic Other Post-Retirement Benefit Costs

	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

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Service cost	$ 3	$ 1	$ 1	$ —	$ 1	$ —	$ —
Interest cost on accumulated post-retirement benefit obligation	35	8	15	8	7	1	4
Expected return on plan assets	(12)	(8)	—	—	—	—	(1)
Amortization of actuarial loss (gain)	6	(3)	22	13	9	(2)	(1)
Amortization of prior service credit	(141)	(14)	(103)	(68)	(35)	—	(1)
Net periodic post-retirement benefit costs(a)(b)	$ (109)	$ (16)	$ (65)	$ (47)	$ (18)	$ (1)	$ 1

(a) Duke Energy amounts exclude $7 million, $7 million and $8 million for the years ended December 2018, 2017 and 2016, 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 2018, 2017 and 2016, 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.

	Piedmont
	Year Ended
(in millions)	**October 31, 2016**
Service cost	$ 1
Interest cost on projected benefit obligation	1
Expected return on plan assets	(2)
Amortization of actuarial loss	1
Net periodic pension costs	$ 1

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets and Liabilities

	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 actuarial gain	**1**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive income	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

	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**
Regulatory assets, net increase (decrease)	$ 71	$ —	$ 81	$ 42	$ 39	$ —	$ (5)	$ (11)
Regulatory liabilities, net increase (decrease)	$ (27)	$ (2)	$ —	$ —	$ —	$ (3)	$ (7)	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (1)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amortization of prior year prior service credit	3	—	—	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ 2	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Piedmont's regulatory assets net decreased $1 million for the two months ended December 31, 2016, and increased $2 million for the year ended October 31, 2016.

Reconciliation of Funded Status to Accrued Other Post-Retirement Benefit Costs

	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 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	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)

	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**
Change in Projected Benefit Obligation								
Accumulated post-retirement benefit obligation at prior measurement date	$ 868	$ 201	$ 357	$ 191	$ 164	$ 32	$ 83	$ 39
Service cost	4	1	—	—	—	—	—	1
Interest cost	34	8	13	7	6	1	3	1
Plan participants' contributions	17	3	6	3	3	1	2	—
Actuarial losses (gains)	4	(3)	4	1	3	—	3	1
Transfers	—	2	(1)	—	(1)	1	—	—
Plan amendments	(28)	(5)	(3)	(1)	(2)	(2)	(2)	(9)
Benefits paid	(86)	(18)	(34)	(17)	(17)	(3)	(11)	(1)
Accumulated post-retirement benefit obligation at measurement date	$ 813	$ 189	$ 342	$ 184	$ 156	$ 30	$ 78	$ 32
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 244	$ 137	$ 1	$ —	$ —	$ 7	$ 22	$ 29
Actual return on plan assets	25	15	1	—	—	2	1	3
Benefits paid	(86)	(18)	(34)	(17)	(17)	(3)	(11)	(1)
Employer contributions (reimbursements)	25	(4)	26	14	14	—	(3)	—
Plan participants' contributions	17	3	6	3	3	1	2	—
Plan assets at measurement date	$ 225	$ 133	$ —	$ —	$ —	$ 7	$ 11	$ 31
Funded status of plan	$ (588)	$ (56)	$ (342)	$ (184)	$ (156)	$ (23)	$ (67)	$ (1)

Amounts Recognized in the Consolidated Balance Sheets

	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	$ 4	$ 2	$ 1	$ —	$ —	$ —	$ —	$ —
Unrecognized prior service credit	(19)	(5)	(7)	(1)	(6)	(1)	(1)	(2)

	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 post-retirement liability[a]	$ 36	$ —	$ 29	$ 15	$ 14	$ 2	$ —	$ —
Noncurrent post-retirement liability[b]	552	56	313	169	142	21	67	1
Total accrued post-retirement liability	$ 588	$ 56	$ 342	$ 184	$ 156	$ 23	$ 67	$ 1
Regulatory assets	$ 125	$ —	$ 129	$ 80	$ 49	$ —	$ 46	$ (4)
Regulatory liabilities	$ 147	$ 44	$ —	$ —	$ —	$ 16	$ 64	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ 4	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit	(2)	—	—	—	—	—	—	—
Net actuarial gain	(10)	—	—	—	—	—	—	—
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)	$ 5	$ 3	$ 1	$ —	$ 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 nine years for Duke Energy, eight years for Duke Energy Carolinas, seven years for Duke Energy Florida, Duke Energy Ohio, and Piedmont, and six years for Progress Energy, Duke Energy Progress, and Duke Energy Indiana.

The following tables present the assumptions used for other post-retirement benefits accounting.

	December 31,		
	2018	**2017**	**2016**
Benefit Obligations			
Discount rate	**4.30%**	3.60%	4.10%
Net Periodic Benefit Cost			
Discount rate	**3.60%**	4.10%	4.40%
Expected long-term rate of return on plan assets	**6.50%**	6.50%	6.50%
Assumed tax rate	**35%**	35%	35%

	Piedmont	
	Two Months Ended December 31, 2016	**Year Ended October 31, 2016**
Benefit Obligations		
Discount rate	4.10%	3.80%
Net Periodic Benefit Cost		
Discount rate	3.80%	4.38%
Expected long-term rate of return on plan assets	6.75%	7.25%

Assumed Health Care Cost Trend Rate

	December 31,	
	2018	**2017**
Health care cost trend rate assumed for next year	**6.50%**	7.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.75%**	4.75%
Year that rate reaches ultimate trend	**2024**	2024

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

(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, 2018							
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)	(5)	(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,								
2019	$ 81	$ 19	$ 30	$ 16	$ 14	$ 3	$ 9	$ 2
2020	75	18	29	15	13	3	8	2
2021	71	18	28	15	13	3	7	2
2022	68	17	27	14	12	3	7	3
2023	64	16	26	14	12	3	6	3
2024-2028	266	64	109	59	50	11	26	12

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. Qualified pension and other post-retirement assets related to Piedmont were transferred into the Duke Energy Master Retirement Trust during 2017. Approximately 98 percent of the Duke Energy Master Retirement Trust assets were allocated to qualified pension plans and approximately 2 percent were allocated to other post-retirement plans (comprised of 401(h) accounts), as of December 31, 2018, and 2017. 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, 2018, Duke Energy assumes pension and other post-retirement plan assets will generate a long-term rate of return of 6.85 percent. 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 percent liability hedging assets and 42 percent 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 $154 million and $195 million at December 31, 2018, and 2017, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned at December 31, 2018, and 2017, respectively. Securities lending income earned by the Duke Energy Master Retirement Trust was immaterial for the years ended December 31, 2018, 2017 and 2016, 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, 2018, and the actual asset allocations for the Duke Energy Master Retirement Trust.

	Target Allocation	Actual Allocation at December 31, 2018	2017
U.S. equity securities	10%	**11%**	11%
Non-U.S. equity securities	8%	**8%**	8%
Global equity securities	10%	**10%**	10%
Global private equity securities	3%	**2%**	2%
Debt securities	63%	**63%**	63%
Hedge funds	2%	**2%**	2%
Real estate and cash	2%	**2%**	2%
Other global securities	2%	**2%**	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, 2018.

	Target Allocation	Actual Allocation at December 31, 2018	2017
U.S. equity securities	32%	**43%**	41%
Non-U.S. equity securities	6%	**8%**	8%
Real estate	2%	**2%**	2%
Debt securities	45%	**40%**	36%
Cash	15%	**7%**	13%
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 16.

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, 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 percent, 31 percent, 15 percent, 16 percent, 5 percent, 7 percent, and 4 percent, respectively, of the Duke Energy Master Retirement Trust 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.

	December 31, 2017				
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Not Categorized[b]
Equity securities	$ 2,823	$ 1,976	$ —	$ —	$ 847
Corporate debt securities	4,694	—	4,694	—	—
Short-term investment funds	246	192	54	—	—
Partnership interests	137	—	—	—	137
Hedge funds	226	—	—	—	226
Real estate limited partnerships	135	—	—	—	135
U.S. government securities	762	—	762	—	—
Guaranteed investment contracts	28	—	—	28	—
Governments bonds – foreign	38	—	38	—	—
Cash	6	6	—	—	—
Government and commercial mortgage backed securities	2	—	2	—	—
Net pending transactions and other investments	17	15	2	—	—
Total assets[a]	$ 9,114	$ 2,189	$ 5,552	$ 28	$ 1,345

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana, and Piedmont were allocated approximately 27 percent, 30 percent, 15 percent, 15 percent, 5 percent, 8 percent, and 4 percent, respectively, of the Duke Energy Master Retirement Trust and Piedmont's Pension assets at December 31, 2017. 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)	2018	2017[a]
Balance at January 1	**$ 28**	$ 38
Sales	**(1)**	(2)
Total gains and other, net	**—**	1
Transfer of Level 3 assets to other classifications	**—**	(9)
Balance at December 31	**$ 27**	$ 28

(a) Balance at January 1 includes $9 million associated with Piedmont pension assets.

Other post-retirement assets

The following tables provide the fair value measurement amounts for VEBA trust assets.

	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

	December 31, 2017	
(in millions)	Total Fair Value	Level 2
Cash and cash equivalents	$ 8	$ 8
Real estate	1	1
Equity securities	28	28
Debt securities	21	21
Total assets	$ 58	$ 58

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 percent of employee before-tax and Roth 401(k) contributions of up to 6 percent 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 percent 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 percent 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[(a)]
Years ended December 31,								
2018	**$ 213**	**$ 68**	**$ 58**	**$ 40**	**$ 19**	**$ 4**	**$ 10**	**$ 12**
2017	179	61	53	37	16	3	9	7
2016	169	57	50	35	15	3	8	

(a) Piedmont's pretax employer matching contributions were $1 million and $7 million during the two months ended December 31, 2016, and for the year ended October 31, 2016, respectively.

Money Purchase Pension Plan

Piedmont sponsored the MPP plan, which is a defined contribution pension plan that allowed employees to direct investments and assume risk of investment returns. Under the MPP plan, Piedmont annually deposited a percentage of each participant’s pay into an account of the MPP plan. This contribution equaled 4 percent of the participant’s eligible compensation plus an additional 4 percent of eligible compensation above the Social Security wage base up to the IRS compensation limit. The participant was vested in MPP plan after three years of service. No contributions were made to the MPP plan during the two months ended December 31, 2016. Piedmont contributed $2 million to the MPP plan during each of the years ended December 31, 2017, and October 31, 2016. Effective December 31, 2017, the MPP Plan was merged into the Retirement Savings Plan and the money purchase plan formula was discontinued. Beginning with the 2018 plan year, the former MPP Plan participants are eligible to receive the additional employer contribution under the Retirement Savings Plan, discussed above.

23. 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 percent, 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 percent 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 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 is 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 as the Company expects to receive this amount via a refund from the IRS in 2019, based on the expected filing of Duke Energy's 2018 income tax return in the second quarter of 2019.

Income Tax Expense

Components of Income Tax Expense

	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)
Investment tax credit 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
Investment tax credit 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.

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Current income taxes							
Federal	$ —	$ 139	$ 15	$ (59)	$ 76	$ (7)	$ 7
State	(15)	25	(19)	(25)	22	(13)	6
Foreign	2	—	—	—	—	—	—
Total current income taxes	(13)	164	(4)	(84)	98	(20)	13
Deferred income taxes							
Federal	1,064	430	486	350	199	88	202
State	117	45	50	40	25	11	11
Total deferred income taxes(a)	1,181	475	536	390	224	99	213
Investment tax credit amortization	(12)	(5)	(5)	(5)	—	(1)	(1)
Income tax expense from continuing operations	1,156	634	527	301	322	78	225
Tax (benefit) expense from discontinued operations	(30)	—	1	—	—	(36)	—
Total income tax expense included in Consolidated Statements of Operations	$ 1,126	$ 634	$ 528	$ 301	$ 322	$ 42	$ 225

(a) Includes benefits of NOL carryforwards and utilization of NOL and tax credit carryforwards of $648 million at Duke Energy, $4 million at Duke Energy Carolinas, $190 million at Progress Energy, $60 million at Duke Energy Progress, $49 million at Duke Energy Florida, $26 million at Duke Energy Ohio and $58 million at Duke Energy Indiana.

	Piedmont	
(in millions)	**Two Months Ended December 31, 2016**	**Year Ended October 31, 2016**
Current income taxes		
Federal	$ 4	$ 27
State	(2)	12
Total current income taxes	2	39
Deferred income taxes		
Federal	24	79
State	6	6
Total deferred income taxes(a)	30	85
Total income tax expense from continuing operations included in Consolidated Statements of Operations	$ 32	$ 124

(a) Includes benefits of NOL and tax carryforwards of $17 million and $91 million for the two months ended December 31, 2016, and the year ended October 31, 2016, respectively.

Duke Energy Income from Continuing Operations before Income Taxes

	Years Ended December 31,		
(in millions)	2018	2017	2016
Domestic[(a)]	$ 3,018	$ 4,207	$ 3,689
Foreign	55	59	45
Income from continuing operations before income taxes	$ 3,073	$ 4,266	$ 3,734

(a) Includes a $16 million expense in 2017 related to the Tax Act impact on equity earnings included within Equity in earnings (losses) of unconsolidated affiliates on the Consolidated Statement of Operations.

Taxes on Foreign Earnings

In February 2016, Duke Energy announced it had initiated a process to divest the International Disposal Group and, accordingly, no longer intended to indefinitely reinvest post-2014 undistributed foreign earnings. This change in the company's intent, combined with the extension of bonus depreciation by Congress in late 2015, allowed Duke Energy to more efficiently utilize foreign tax credits and reduce U.S. deferred tax liabilities associated with the historical unremitted foreign earnings by approximately $95 million during the year ended December 31, 2016.

Due to the classification of the International Disposal Group as discontinued operations beginning in the fourth quarter of 2016, income tax amounts related to the International Disposal Group's foreign earnings are presented within Income (Loss) From Discontinued Operations, net of tax on the Consolidated Statements of Operations. In December 2016, Duke Energy closed on the sale of the International Disposal Group in two separate transactions to execute the divestiture. See Note 2 for additional information on the sale.

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, 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 percent	$ 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 production tax credits	(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 net operating losses, 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 percent	$ 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 production tax credits	(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 net operating losses, and valuation allowance on foreign tax credits.

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Income tax expense, computed at the statutory rate of 35 percent	$ 1,307	$ 630	$ 548	$ 315	$ 306	$ 95	$ 212
State income tax, net of federal income tax effect	64	46	20	10	30	(2)	11
AFUDC equity income	(70)	(36)	(26)	(17)	(9)	(2)	(6)
Renewable energy production tax credits	(97)	—	—	—	—	—	—
Audit adjustment	5	3	—	—	—	—	—
Tax true up	(14)	(14)	(11)	(3)	(9)	(16)	2
Other items, net	(39)	5	(4)	(4)	4	3	6
Income tax expense from continuing operations	$ 1,156	$ 634	$ 527	$ 301	$ 322	$ 78	$ 225
Effective tax rate	31.0%	35.2%	33.7%	33.4%	36.9%	28.9%	37.1%

	Piedmont	
(in millions)	**Two Months Ended December 31, 2016**	**Year Ended October 31, 2016**
Income tax expense, computed at the statutory rate of 35 percent	$ 30	$ 111
State income tax, net of federal income tax effect	1	11
Other items, net	1	2
Income tax expense from continuing operations	$ 32	$ 124
Effective tax rate	37.2%	39.1%

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 the State income tax, net of federal income tax effect in the above tables.

DEFERRED TAXES

Net Deferred Income Tax Liability Components

	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
Capital 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 capital lease obligations and debt fair value adjustments.

The following table presents the expiration of tax credits and NOL carryforwards.

	December 31, 2018	
(in millions)	**Amount**	**Expiration Year**
Investment tax credits	$ 1,614	2024 — 2038
Alternative minimum tax credits	574	Refundable by 2021
Federal NOL carryforwards[(a)(e)]	788	2022 — Indefinite
State NOL carryforwards and credits[(b)(e)]	301	2019 — Indefinite
Foreign NOL carryforwards[(c)]	12	2027 — 2037
Foreign Tax Credits[(d)]	1,271	2024 — 2027
Charitable contribution carryforwards	20	2019 — 2023
Total tax credits and NOL carryforwards	$ 4,580	

(a) 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 $85 million has been recorded on the state NOL 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 $383 million has been recorded on the foreign tax credits, as presented in the Net Deferred Income Tax Liability Components table.

(e) 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, 2017							
(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	$ 143	$ 33	$ 78	$ 23	$ 49	$ 11	$ 6	$ (5)
Capital lease obligations	49	14	—	—	—	—	2	—
Pension, post-retirement and other employee benefits	295	(17)	111	44	60	14	18	(4)
Progress Energy merger purchase accounting adjustments[(a)]	536	—	—	—	—	—	—	—
Tax credits and NOL carryforwards	4,527	234	402	156	143	25	216	70
Regulatory liabilities and deferred credits	—	222	—	—	—	65	—	61
Investments and other assets	—	—	—	—	—	—	1	18
Other	73	10	1	4	—	—	—	—
Valuation allowance	(519)	—	(14)	—	—	—	—	—
Total deferred income tax assets	5,104	496	578	227	252	115	243	140
Investments and other assets	(1,419)	(849)	(470)	(289)	(187)	—	(14)	—
Accelerated depreciation rates	(9,216)	(3,060)	(2,803)	(1,583)	(1,257)	(896)	(966)	(697)
Regulatory assets and deferred debits, net	(1,090)	—	(807)	(238)	(569)	—	(188)	—
Other	—	—	—	—	—	—	—	(7)
Total deferred income tax liabilities	(11,725)	(3,909)	(4,080)	(2,110)	(2,013)	(896)	(1,168)	(704)
Net deferred income tax liabilities	$ (6,621)	$ (3,413)	$ (3,502)	$ (1,883)	$ (1,761)	$ (781)	$ (925)	$ (564)

(a) Primarily related to capital lease obligations and debt fair value adjustments.

On June 28, 2017, the North Carolina General Assembly amended N.C. Gen. Stat. 105-130.3, reducing the North Carolina corporate income tax rate from a statutory rate of 3.0 to 2.5 percent beginning January 1, 2019. Duke Energy recorded a net reduction of approximately $55 million to their North Carolina deferred tax liabilities in the second quarter of 2017. The significant majority of this deferred tax liability reduction was offset by recording a regulatory liability pending NCUC determination of the disposition of amounts related to Duke Energy Carolinas, Duke Energy Progress and Piedmont. The impact did not have a significant impact on the financial position, results of operation or cash flows of Duke Energy, Duke Energy Carolinas, Progress Energy or Duke Energy Progress.

UNRECOGNIZED TAX BENEFITS

The following tables present changes to unrecognized tax benefits.

	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 – current period tax positions	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

	Year Ended December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Unrecognized tax benefits – January 1	$ 88	$ 72	$ 1	$ 3	$ —	$ —	$ 1
Unrecognized tax benefits increases (decreases)							
Gross increases – tax positions in prior periods	—	—	—	—	4	4	—
Gross decreases – tax positions in prior periods	(4)	(4)	(1)	(1)	—	—	—
Decreases due to settlements	(68)	(67)	—	—	—	—	(1)
Reduction due to lapse of statute of limitations	1	—	2	—	—	—	—
Total changes	(71)	(71)	1	(1)	4	4	(1)
Unrecognized tax benefits – December 31	$ 17	$ 1	$ 2	$ 2	$ 4	$ 4	—

The following table includes additional information regarding the Duke Energy Registrants' unrecognized tax benefits at December 31, 2018. All Duke Energy Registrants do not anticipate a material increase or decrease in unrecognized tax benefits within the next 12 months.

	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**
Amount that if recognized, would affect the effective tax rate or regulatory liability[(a)]	**$ 21**	**$ 6**	**$ 9**	**$ 6**	**$ 3**	**$ 1**	**$ 1**	**$ 4**
Amount that if recognized, would be recorded as a component of discontinued operations	**2**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

(a) Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana and Piedmont 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, 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	—

	Year Ended December 31, 2016				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**
Net interest income recognized related to income taxes	$ —	$ —	$ 1	$ —	$ 2
Net interest expense recognized related to income taxes	—	7	—	—	—
Interest payable related to income taxes	4	23	1	1	—

Piedmont recognized $1 million in net interest income related to income taxes in the Consolidated Statements of Operations for the year ended October 31, 2016.

Duke Energy and its subsidiaries are no longer subject to U.S. federal examination for years before 2015. 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 2015.

24. 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, 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)

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Interest income	$ 21	$ 4	$ 4	$ 3	$ 2	$ 5	$ 6
AFUDC equity	200	102	76	50	26	6	16
Post in-service equity returns	67	55	12	12	—	—	—
Nonoperating income, other	175	53	94	67	35	—	4
Other income and expense, net[(a)]	$ 463	$ 214	$ 186	$ 132	$ 63	$ 11	$ 26

(a) Amounts for Piedmont for the two months ended December 31, 2016, and for the year ended October 31, 2016, were not material.

25. SUBSEQUENT EVENTS

For information on subsequent events related to the adoption of the new lease accounting standard, regulatory matters, commitments and contingencies and debt and credit facilities, see Notes 1, 4, 5 and 6, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	(588,666)			
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	936,642			
3	Preceding Quarter/Year to Date Changes in Fair Value	(347,977)			
4	Total (lines 2 and 3)	588,665			
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)			

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	(8,909,104)		(9,497,770)		
2	1,828,661		2,765,303		
3			(347,977)		
4	1,828,661		2,417,326	1,214,747,120	1,217,164,446
5	(7,080,443)		(7,080,444)		
6	(7,080,443)		(7,080,444)		
7	912,553		912,553		
8					
9	912,553		912,553	1,070,378,654	1,071,291,207
10	(6,167,890)		(6,167,891)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	34,950,512,362	34,950,512,362
4	Property Under Capital Leases	135,090,542	135,090,542
5	Plant Purchased or Sold		
6	Completed Construction not Classified	6,001,606,839	6,001,606,839
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	41,087,209,743	41,087,209,743
9	Leased to Others		
10	Held for Future Use	74,369,173	74,369,173
11	Construction Work in Progress	1,632,658,461	1,632,658,461
12	Acquisition Adjustments	284,107	284,107
13	Total Utility Plant (8 thru 12)	42,794,521,484	42,794,521,484
14	Accum Prov for Depr, Amort, & Depl	15,937,831,422	15,937,831,422
15	Net Utility Plant (13 less 14)	26,856,690,062	26,856,690,062
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	15,321,614,259	15,321,614,259
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	615,947,489	615,947,489
22	Total In Service (18 thru 21)	15,937,561,748	15,937,561,748
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	269,674	269,674
33	Total Accum Prov (equals 14) (22,26,30,31,32)	15,937,831,422	15,937,831,422

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
					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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	5,556,378	44,464,059
3	Nuclear Materials	268,010,963	188,030,146
4	Allowance for Funds Used during Construction	41,626,341	15,994,350
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	315,193,682	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	1	287,214,570
9	In Reactor (120.3)	1,158,802,565	287,214,570
10	SUBTOTAL (Total 8 & 9)	1,158,802,566	
11	Spent Nuclear Fuel (120.4)	652,248,802	293,784,059
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	1,283,591,983	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	842,653,067	
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)		

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
	43,288,910	6,731,527	2
	233,115,593	222,925,516	3
	10,810,067	46,810,624	4
			5
		276,467,667	6
			7
	287,214,570	1	8
	293,784,058	1,152,233,077	9
		1,152,233,078	10
	470,763,860	475,269,001	11
			12
-275,311,826	469,229,790	1,089,674,019	13
		814,295,727	14
			15
			16
			17
			18
			19
			20
			21
			22

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

Total includes $470,763,860 of nuclear fuel assemblies and ($1,534,070) of nuclear fuel canisters that have been retired.

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	
4	(303) Miscellaneous Intangible Plant	932,856,950	43,331,718
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	943,490,978	43,331,718
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	29,048,540	
9	(311) Structures and Improvements	742,619,276	377,396,549
10	(312) Boiler Plant Equipment	5,301,253,896	301,212,382
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	916,999,715	52,183,060
13	(315) Accessory Electric Equipment	394,382,489	1,870,048
14	(316) Misc. Power Plant Equipment	360,255,298	5,325,750
15	(317) Asset Retirement Costs for Steam Production	799,989,687	158,796,530
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	8,544,548,901	896,784,319
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	2,882,536	158,907
19	(321) Structures and Improvements	1,885,296,595	22,279,559
20	(322) Reactor Plant Equipment	3,774,274,928	114,083,024
21	(323) Turbogenerator Units	976,233,783	3,435,758
22	(324) Accessory Electric Equipment	1,165,998,322	74,933,270
23	(325) Misc. Power Plant Equipment	536,150,283	36,160,740
24	(326) Asset Retirement Costs for Nuclear Production	-607,602,839	274,522,234
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	7,733,233,608	525,573,492
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	52,334,298	8
28	(331) Structures and Improvements	402,516,160	8,226,461
29	(332) Reservoirs, Dams, and Waterways	829,079,580	24,465,100
30	(333) Water Wheels, Turbines, and Generators	644,734,270	17,594,013
31	(334) Accessory Electric Equipment	143,219,730	6,632,189
32	(335) Misc. Power PLant Equipment	50,187,670	2,733,277
33	(336) Roads, Railroads, and Bridges	21,796,265	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	2,143,867,973	59,651,048
36	D. Other Production Plant		
37	(340) Land and Land Rights	9,171,919	191,853
38	(341) Structures and Improvements	353,588,327	14,928,582
39	(342) Fuel Holders, Products, and Accessories	118,619,083	65,355,708
40	(343) Prime Movers	928,745,321	414,499,976
41	(344) Generators	951,943,728	64,533,730
42	(345) Accessory Electric Equipment	148,753,727	66,048,964
43	(346) Misc. Power Plant Equipment	29,962,911	8,264,077
44	(347) Asset Retirement Costs for Other Production	6,571,313	8,204,768
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,547,356,329	642,027,658
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	20,969,006,811	2,124,036,517

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	195,332,778	1,160,032
49	(352) Structures and Improvements	103,118,867	5,765,561
50	(353) Station Equipment	1,766,593,572	140,160,003
51	(354) Towers and Fixtures	568,724,054	20,653,141
52	(355) Poles and Fixtures	499,096,613	64,795,129
53	(356) Overhead Conductors and Devices	735,906,268	28,084,066
54	(357) Underground Conduit	124,174	
55	(358) Underground Conductors and Devices	5,812,274	-272
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)	3,874,750,838	260,617,660
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	64,198,609	-414,675
61	(361) Structures and Improvements	105,367,985	9,498,255
62	(362) Station Equipment	1,318,816,817	84,683,781
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,526,567,463	119,261,064
65	(365) Overhead Conductors and Devices	2,143,620,189	147,215,917
66	(366) Underground Conduit	198,792,030	7,788,018
67	(367) Underground Conductors and Devices	1,927,865,633	122,101,228
68	(368) Line Transformers	1,412,898,306	110,279,775
69	(369) Services	1,049,289,043	63,019,566
70	(370) Meters	528,916,769	101,087,278
71	(371) Installations on Customer Premises	841,249,312	78,482,118
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	228,147,481	18,926,628
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	11,345,729,637	861,928,953
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	646,838,651	39,974,725
88	(391) Office Furniture and Equipment	124,261,808	54,924,568
89	(392) Transportation Equipment	10,701,691	2,659,144
90	(393) Stores Equipment	13,568,044	141,045
91	(394) Tools, Shop and Garage Equipment	95,914,343	8,922,141
92	(395) Laboratory Equipment	6,160,536	108,025
93	(396) Power Operated Equipment	13,229,675	-965,430
94	(397) Communication Equipment	139,278,371	27,388,554
95	(398) Miscellaneous Equipment	9,590,065	1,260,529
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,122,460,321	134,413,301
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)	1,121,528,986	134,413,301
100	TOTAL (Accounts 101 and 106)	38,254,507,250	3,424,328,149
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)	38,254,507,250	3,424,328,149

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
			10,634,028		3
71,826			976,116,842		4
71,826			986,750,870		5
					6
					7
97,748		-17,945	28,932,847		8
35,258,895			1,084,756,930		9
107,326,017		-164,942	5,494,975,319		10
					11
13,221,676			955,961,099		12
546,785		164,942	395,870,694		13
716,041		-5,440	364,859,567		14
71,832,116			886,954,101		15
228,999,278		-23,385	9,212,310,557		16
					17
			3,041,443		18
11,821,518			1,895,754,636		19
43,894,316			3,844,463,636		20
1,766,903			977,902,638		21
11,734,236			1,229,197,356		22
1,134,925			571,176,098		23
			-333,080,605		24
70,351,898			8,188,455,202		25
					26
-12,544			52,346,850		27
2,142,781			408,599,840		28
3,562,347			849,982,333		29
4,432,815			657,895,468		30
6,774,987			143,076,932		31
82,603			52,838,344		32
			21,796,265		33
					34
16,982,989			2,186,536,032		35
					36
			9,363,772		37
482,112		-20,665	368,014,132		38
1,073,616			182,901,175		39
8,491,790		178,148	1,334,931,655		40
15,594,054		-157,483	1,000,725,921		41
1,096,403			213,706,288		42
99,152		5,440	38,133,276		43
			14,776,081		44
26,837,127		5,440	3,162,552,300		45
343,171,292		-17,945	22,749,854,091		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
119,451			196,373,359		48
3,466,219		-1,621,506	103,796,703		49
64,203,319		-2,794,756	1,839,755,500		50
1,732,072			587,645,123		51
4,714,233		-492,978	558,684,531		52
2,961,529		-515,116	760,513,689		53
			124,174		54
			5,812,002		55
			42,238		56
					57
77,196,823		-5,424,356	4,052,747,319		58
					59
2,331			63,781,603		60
2,996,889		958,632	112,827,983		61
28,627,040		1,774,319	1,376,647,877		62
					63
10,907,548		-1,785,463	1,633,135,516		64
25,452,074		-1,743,712	2,263,640,320		65
353,425		-2,276,773	203,949,850		66
6,828,272		-2,276,772	2,040,861,817		67
2,196,885		-2,276,772	1,518,704,424		68
2,194,397		-2,613,648	1,107,500,564		69
41,206,993		18,551,059	607,348,113		70
3,442,747		-2,276,773	914,011,910		71
					72
1,403,736		-2,276,773	243,393,600		73
					74
125,612,337		3,757,324	12,085,803,577		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			62,917,137		86
12,299,715		536,248	675,049,909		87
16,597,819			162,588,557		88
920,062		196,004	12,636,777		89
70,871		660,711	14,298,929		90
42,888			104,793,596		91
391,102			5,877,459		92
79,545		-856,714	11,327,986		93
14,724,511		1,276,765	153,219,179		94
574,902			10,275,692		95
45,701,415		1,813,014	1,212,985,221		96
					97
			-931,335		98
45,701,415		1,813,014	1,212,053,886		99
591,753,693		128,037	41,087,209,743		100
					101
					102
					103
591,753,693		128,037	41,087,209,743		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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					
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					
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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	LEE NUCLEAR PLANT COMMON - CHEROKEE, SC	6/2018	2020	40,939,833
3	APPLE TIE - CATAWBA, NC	11/2017	2021	6,752,142
4	CRAMERTON RETAIL - GASTON, NC	5/2017	2020	4,414,819
5	FERNCLIFF RETAIL - HENDERSON, NC	5/2017	2020	3,100,712
6	RICHBURG RETAIL STATION - CHESTER, SC	1/2017	2019	1,464,831
7	FURR ROAD RETAIL - HUNTERSVILLE, NC	10/2011	2022	1,227,200
8	NORTH ALEXANDER STREET RETAIL SUB - CHARLOTTE, NC	3/2012	2020	959,967
9	LAKE NORMAN 525KV RIGHT OF WAY - CORNELIUS, NC	1/1980	2024	937,983
10	GALENOR THREE BREAKER STATION - CALDWELL, NC	10/2017	2037	911,520
11	PATTERSON SPRINGS RETAIL - CLEVELAND, NC	1/2017	2020	808,427
12	BELMEADE RETAIL - MECKLENBURG, NC	11/2012	2020	804,674
13	SOCK HILL RETAIL - SPARTANBURG, SC	1/2017	2019	628,785
14	KANOY RETAIL LOT - THOMASVILLE, NC	7/2010	2021	575,861
15	BRANSON MILL RD RET - RANDOLPH, NC	11/2013	2022	572,418
16	STOCKESDALE RETAIL - GUILFORD, NC	5/2016	2020	536,572
17	LAYCOCK RETAIL - HENDERSON, NC	10/2016	2020	523,233
18	SHOFFNER RETAIL SUBSTATION - GREENSBORO, NC	12/2009	2019	512,693
19	KERWIN CIRCLE RETAIL - KERNERSVILLE, NC	6/2009	2022	512,463
20	DORMAN RD RETAIL - MECKLENBURG, NC	6/2012	2020	459,800
21	Other Property:			
22	CALICO RD RETAIL - CALDWELL, NC	1/2012	2020	427,771
23	MATRIX RETAIL - GREENVILLE, SC	3/2016	2019	415,171
24	REVOLUTION MILL RETAIL SUBSTATION - GREENSBORO, NC	10/2011	2019	400,257
25	LIBERTY SITE - GILFORD, NC	1/2017	2020	385,745
26	HIGHWAY 24 RETAIL - ANDERSON, SC	12/2008	2022	384,198
27	EDGEFIELD RETAIL - GREENSBORO, NC	2/2012	2020	370,486
28	CANTERBURRY RETAIL - GREENVILLE, SC	4/2016	2020	369,588
29	ROEBUCK RETAIL LOT - SPARTANBURG, SC	2/2012	2024	364,453
30	HERMAN RD RETAIL - CATAWBA NC	4/2016	2025	351,579
31	LONG ISLAND ROAD RETAIL - CATAWBA, NC	5/2009	2022	308,738
32	SKYLAND RETAIL - WINSTON-SALEM, NC	1/1990	2025	303,819
33	KEOWEE PLT PICKENS INSURABLE - SALEM, NC	10/2016	2030	284,915
34	LITTLE MOUNTAIN ROAD RETAIL - GASTONIA, NC	12/2008	2022	282,811
35	Other Land Rights < $250K (57 items)			3,075,709
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			74,369,173

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	(Mo, Da, Yr) 05/29/2019	End of 2018/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	30,353,744
4	HOLT RETAIL - NEW SUBSTATION	8,921,079
5	BUSINESS UNIT 20017 DISTRIBUTION SUBSTATION	8,723,239
6	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - SOUTH CAROLINA	8,031,503
7	SMARTGRID CABLE	7,644,213
8	SHACKTOWN RETAIL - NEW SUBSTATION	6,785,717
9	SMARTGRID TARGETED OVERHEAD/UNDERGROUND CONVERSION	5,693,092
10	GENESTU DRIVE RETAIL - NEW SUBSTATION	5,521,928
11	BUSTER BOYD RETAIL - NEW SUBSTATION	5,223,314
12	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - NP&L NORTH CAROLINA	4,905,869
13	GM 0405 TO FERNWOOD 0403 TRANSFER	4,893,315
14	ELLISBORO RETAIL - NEW SUBSTATION	4,168,156
15	WACO #2 - CONVERT TO 100 KV	4,043,046
16	TOWN CREEK TO WESTLAKE NETWORK LINES	3,606,423
17	KNIGHTS RETAIL SUBSTATION CAPACITY - TRANSFORMER AND ASSOCIATED EQUIPMENT	3,486,804
18	FIDDLERS CREEK - TRANSFORMER BANK CAPACITY	3,285,392
19	DISTRIBUTION LIGHTING INSTALLATION - NORTH CAROLINA	3,102,298
20	ONEAL RETAIL - TRANSFORMER ADDITION	2,929,414
21	PLATO LEE SUBSTATION	2,892,822
22	BUSTER BOYD RETAIL - NEW SUBSTATION WITH TWO NEW CIRCUITS	2,830,234
23	SMARTGRID SELF-HEALING TEAMS	2,651,110
24	DISTRIBUTION LINE RELOCATIONS/MODIFICATIONS - NORTH CAROLINA	2,568,734
25	WADDELL ROAD RETAIL - TRANSFORMER BANK ADDITION	2,449,916
26	WADDELL ROAD RETAIL - TRANSFORMER BANKS	1,956,503
27	KNIGHTS RETAIL - NEW CIRCUIT	1,947,562
28	BROUGHTON RETAIL - TRANSFORMER BANK	1,768,673
29	SMARTGRID FEEDER CAPACITY	1,753,057
30	CRAMER MOUNT - UNDERGROUND PRIMARY	1,716,086
31	CLEVELAND RETAIL - TRANSFORMER BANK	1,710,828
32	RUSD FEEDER CAPACITY	1,457,605
33	DACIAN AVENUE RETAIL - TRANSFORMER	1,454,379
34	OWINGS RETAIL - NEW SUBSTATION	1,444,337
35	WARE PLACE RETAIL - TRANSFORMER BANK CAPACITY	1,410,547
36	SPEEDWAY 2411 RECONDUCTOR	1,334,468
37	TODDVILLE PORTABLE TRANSFORMER	1,331,870
38	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - NP&L CHEROKEE	1,255,381
39	CARMEL ROAD RETAIL - CIRCUIT RELOCATION	1,167,006
40	DISTRIBUTION LIGHTING INSTALLATION - NP&L	1,166,118
41	BROAD 0403 TO BROAD 1203 TRANSFORMER	1,145,638
42	EASTOVER RETAIL - TRANSFORMER BANK ADDITION	1,128,671
43	TOTAL	1,632,658,461

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	KENILWORTH RETAIL - SUBSTATION CAPACITY	1,075,371
2	SUMMIT AVENUE RETAIL - TRANSFORMER BANK	1,044,168
3	GREENBRIAR - NEW CIRCUIT PHASE 2	1,039,696
4	WOODLEAF SOLAR - CABLE INSTALLATION	1,006,024
5	PROJECTS LESS THAN $1 MILLION	62,376,068
6	TOTAL DISTRIBUTION PLANT $226,401,418	
7		
8	GENERAL PLANT	
9		
10	ELECTRIC BUSINESS SEGMENT - UNIVERSAL PARK CHARLOTTE NC - CUSTOMER SERVICE CENTER	21,241,616
11	TELECOM MICROWAVE PROJECTS - NORTH CAROLINA	12,879,419
12	REAL ESTATE SERVICES - CAROLINA EAST CAPITAL LOCATIONS	10,760,290
13	GENERAL ACCRUAL FOR DUKE POWER	10,142,540
14	REAL ESTATE SERVICES - MISCELLANEOUS CAROLINAS WEST GENERAL PLANT PROJECTS	7,603,666
15	CHARLOTTE METRO - CONSTRUCT NEW OFFICE TOWER	4,960,938
16	TOWERS, SHELTERS & POWER SUPPLIES	4,360,601
17	IT DEMAND WORK FUNDING PROJECT	3,223,517
18	SMARTGRID DEE SECURE NETWORK INFRASTRUCTURE	2,601,392
19	SMARTGRID DEE DISTRIBUTED MANAGEMENT SYSTEM ADMS	2,092,281
20	PANASONIC UNITS - CAROLINAS EAST	1,940,270
21	DEC MICROWAVE	1,849,967
22	CUSTOMER CONNECT	1,778,480
23	SMARTGRID DEE METER FARM	1,545,287
24	REAL ESTATE SERVICES - GENERAL PLANT WORK	1,463,158
25	GRIDWAN CORE ROUTER UPFIT	1,399,812
26	ON SITE GENERATION EQUIPMENT FOR PRYSMIAN CABLES AND SYSTEMS	1,172,256
27	NERC CIP COMPLIANCE - ROUTERS, SWITCHES, CARD READERS INSTALLATION	1,077,347
28	TELECOM MICROWAVE PROJECTS - SOUTH CAROLINA	1,035,078
29	PROJECTS LESS THAN $1 MILLION	7,102,610
30	TOTAL GENERAL PLANT $100,230,525	
31		
32	INTANGIBLE PLANT	
33		
34	CUSTOMER CONNECT	20,845,935
35	SMARTGRID DEE DISTRIBUTED MANAGEMENT SYSTEM ADMS	14,236,520
36	SMARTGRID DISTRIBUTED MANAGEMENT SYSTEM PROJECT #3	10,033,653
37	SMARTGRID TRANSMISSION OUTAGE APPLICATION SOFTWARE	8,896,910
38	CATAWBA WATEREE RELICENSING	6,628,585
39	IT DEMAND WORK FUNDING PROJECT	5,439,783
40	SMARTGRID DEE TRANSMISSION HEALTH RISK MANAGEMENT	4,949,674
41	OCONEE UNIT 1 MEASUREMENT UNCERTAINTY RECAPTURE RATE	4,271,860
42	OCONEE UNIT 3 MEASUREMENT UNCERTAINTY RECAPTURE RATE	3,767,650
43	TOTAL	1,632,658,461

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	OCONEE UNIT 2 MEASUREMENT UNCERTAINTY RECAPTURE RATE	3,517,257
2	OCONEE CORE MONITORING SOFTWARE AND SERVERS	3,452,326
3	DEE ADVANCED METERING INFRASTRCTURE OPERATIONS CENTER	2,596,872
4	SMARTGRID DISTRIBUTED MANAGEMENT SYSTEM ENHANCEMENTS	2,575,578
5	SMARTGIRD DISTRIBUTED MANAGEMENT SYSTEM CONSOLIDATION - TED THOMAS TOWER	2,278,297
6	ARCOS SYSTEM OUTAGE STAFFING PROJECT	1,939,696
7	APPLICATION ENHANCEMENTS AND FIXES	1,173,681
8	SMARTGRID DATA ANALYTICS (ASSET MANAGEMENT) - JESSICA BISHOP TOWER	1,171,732
9	PROJECTS LESS THAN $1 MILLION	8,301,726
10	TOTAL INTANGIBLE PLANT $106,077,735	
11		
12	PRODUCTION PLANT	
13		
14	OCONEE MAIN STREAM ISOLATION VALVES	84,839,113
15	KEOWEE GENERATOR STATOR OVERHAUL	78,887,762
16	MARSHALL ENHANCED FLUE GAS DESULFURIZATION WASTEWATER TREATMENT	73,194,563
17	BRIDGEWATER LINVILLE DAM	68,048,168
18	ALLEN STEAM DRY BOTTOM ASH CONVERSION	61,057,762
19	OCONEE PLANT UNIT 2 LOW PRESSURE TURBINE	34,264,839
20	OCONEE PLANT UNIT 1 LOW PRESSURE TURBINE	33,348,636
21	BELEWS CREEK CCP STORM WATER / PROCESS WATER REROUTE	24,402,779
22	CLEMSON COMBINED HEAT AND POWER PROJECT	23,191,532
23	BELEWS CREEK DUAL FUEL COFIRING	21,714,053
24	CLIFFSIDE 5&6 STORM WATER / PROCESS WATER REROUTE	20,346,260
25	MARSHALL NATURAL GAS ADDITION FOR WARMUP / COFIRING	17,552,541
26	OCONEE ROOF TURBINE U1, U2, U3	16,737,789
27	MARSHALL STEAM PLANT SCR INSTALLATION	13,536,829
28	CLIFFSIDE 5&6 STORMWATER SURGE BASIN	13,222,132
29	CEDAR CLIFF POWER HOUSE DAM INFLOW DESIGN FLOOD SPILLWAY & GATE HOUSE	12,619,723
30	OCONEE UNIT 1 MEASUREMENT UNCERTAINTY RECAPTURE RATE	12,362,522
31	OCONEE SSF ELECTRICAL GENERATOR	11,663,427
32	MCGUIRE LICENSE RENEWAL	11,202,350
33	BAD CREEK UNIT 2 UPRATE PROJECT	10,115,673
34	OCONEE UNIT 2 MEASUREMENT UNCERTAINTY RECAPTURE RATE	9,446,271
35	OCONEE UNIT 1 PLANT SSF LETDOWN LINE	9,041,399
36	OCONEE UNIT 3 MEASUREMENT UNCERTAINTY RECAPTURE RATE	8,967,400
37	WYLIE PLANT UNIT 4 AERATING RUNNER	8,388,107
38	COWANS FORD UNIT 4 LIFE EXTENSION ELECTRICAL	7,888,101
39	OCONEE PLANT UNIT 2 OPEN PHASE FAULT DETECTION SYSTEM	7,646,000
40	ALLEN STEAM ENHANCED FLUE GAS DESULFURIZATION WASTEWATER TREATMENT	7,364,162
41	MCGUIRE UNIT 2 MAIN POWER RELAYING	7,308,982
42	COWANS FORD UNIT 4 LIFE EXTENSION MECHANICAL	7,247,264
43	TOTAL	1,632,658,461

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	OCONEE SUPPLEMENTAL LICENSE REQUEST	7,008,641
2	SECURITY BREACH AND DEFENSIVE POSITIONS	6,760,073
3	MCGUIRE UNIT 1 DISTRIBUTED CONTROL SYSTEM SERVER PROJECTOR	6,652,343
4	BELEWS CREEK HORIZONTAL PRIMARY REHEAT SECTION REDSIGN	6,308,762
5	LINCOLN NEW COMBUSTION TURBINE UNIT	6,200,990
6	OCONEE CYBER SECURITY MITIGATION SECURITY SYSTEMS	6,147,276
7	MCGUIRE INSTALL OPEN PHASE DETECTION	5,515,652
8	CATAWBA UNIT 1 TURBINE STEAM PATH	5,396,087
9	MCGUIRE PHASE IV DRY STORAGE	4,850,657
10	MARSHALL DRY FLY ASH SYSTEM EVALUATION & REDUNDANCY	4,849,054
11	OCONEE RPS/ES ADDITIONAL WORK	4,427,334
12	OCONEE DRY STORAGE PHASE 8	4,395,828
13	MARSHALL COAL CRUSHER MOTORS	4,255,259
14	LOOKOUT SHOALS PLANT - SEISMIC NET PROJECT	4,210,249
15	BELEWS CREEK UNIT 2 AIR PREHEATER BASKETS AND SEALS	4,159,408
16	MCGUIRE OPEN PHASE FAULT DETECTION	4,066,332
17	OCONEE OPEN PHASE COMBUSTION TURBINE 5	3,927,447
18	OCONEE UNIT 3 OPEN PHASE FAULT DETECTION	3,765,348
19	DEARBORN DIVERSION DAM STRUCTURAL MODIFICATIONS	3,600,999
20	OCONEE UNIT 1 LOW PRESSURE TURBINE	3,580,376
21	CATAWBA UNIT 2 TURBINE STEAM PATH	3,512,276
22	OCONEE UNIT 1 CYBER SECURITY MITIGATION	3,444,718
23	OCONEE UNIT 2 CYBER SECURITY MITIGATION	3,413,226
24	OCONEE UNIT 3 CYBER SECURITY MITIGATION	3,408,365
25	MCGUIRE UNIT 2 DISTRIBUTED CONTROL SYSTEM SERVER PROJECT	3,348,674
26	MCGUIRE UNIT 1 & UNIT 2 POLAR CRANE METER & CONTROLS	3,260,662
27	OCONEE UNIT 2 PLANT SSF LETDOWN LINE	3,230,509
28	IT DEMAND WORK FUNDING PROJECT	2,972,181
29	OCONEE UNIT 1 SSF INSTRUMENTATION AND TORNADO LAR	2,798,493
30	OCONEE UNIT 1 OPEN PHASE FAULT DETECTION	2,789,588
31	OCONEE PLANT MOLDED CASE BREAKERS	2,687,819
32	BEAR CREEK ALTERNATE GATE LIFTING	2,548,166
33	CLIFFSIDE 5&6 FILTERED AIR PRESSURIZATION SYSTEM INSTALLATION	2,489,099
34	CLIFFSIDE 5&6 PURCHASE LAND AROUND LANDFILL	2,453,036
35	OCONEE UNIT 3 PLANT SSF LETDOWN LINE	2,401,567
36	OCONEE OPEN PHASE FAULT DETECTION - KEOWEE	2,385,536
37	CLIFFSIDE UNIT 5 BIOREACTOR WASTE WATER TREATMENT	2,371,349
38	OCONEE SSF SUMP PUMP/PIPING	2,337,004
39	MCGUIRE UNIT 1 GENERATOR STATOR REFURBISHMENT	2,329,311
40	OCONEE PLANT - ISFSI PHASE 9 HSM INSTALLATION	2,031,230
41	WYLIE PLANT TRASH RACKS STOP LOGS SYSTEM	2,019,762
42	ALLEN STEAM AIR PREHEATER WASH WATER TANK	1,968,404
43	TOTAL	1,632,658,461

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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	MOUNTAIN ISLAND DAM SEISMIC	1,891,837
2	MCGUIRE UNIT 2 RN SUCTION OVERPRESSURE PROTECTION SYSTEM	1,861,796
3	OCONEE UNIT 2 HPI MOTOR	1,857,868
4	MCGUIRE UNIT 2 ROTORK NA2 ACTUATOR	1,834,985
5	MCGUIRE UNIT 1 ROTORK NA2 ACTUATOR	1,821,523
6	MCGUIRE UNIT 1 RN SUCTION OVERPRESSURE PROTECTION SYSTEM	1,730,908
7	OCONEE MAIN GENERATOR RELAY PANEL	1,678,113
8	CLIFFSIDE 5&6 DESIGN AIR PREHEATER WASH WATER TANK	1,642,668
9	BELEWS CREEK UNIT 2 EH SYSTEM PUMP/RESERVOIR SKID AND ASSOCIATED EQUIPMENT	1,599,466
10	WS LEE COMBINED CYCLE - SMARTGEN HARDWARE INSTALLATION	1,567,704
11	OCONEE KEOWEE SUMP PIPING REROUTE	1,548,371
12	CLIFFSIDE UNIT 6 CAPITAL VALVES	1,528,225
13	BUCK COMBINED CYCLE MAJOR INTERNAL INSPECTION OF GT11	1,478,207
14	TANASEE CREEK ALTERNATE LIFTING GATE	1,282,634
15	COWANS FORD LIFE EXTENSION - CONTROLS WORK AND COMMON GENERATOR REWINDS	1,227,070
16	MCGUIRE PLANT - PURCHASE UNIT 2 DIGITAL ROD POSITION INDICATION DETECTOR ENCODER	1,110,592
17	NUCLEAR ALERT & NOTIFICATION SYSTEM	1,108,105
18	PRYSMIAN GROUP - FIBER PLANT AND CABLE PLANT	1,102,411
19	MOUNTAIN ISLAND FOREBAY STOP LOGS	1,102,211
20	OCONEE PLANT-SF-2 GATE VALVE	1,027,796
21	MCGUIRE PLANT ISFSI PHASE 4 TEMPERATURE MONITOR SYSTEM & SECURITY CAMERAS	1,027,764
22	CEDAR CREEK UNIT 1 GENERATOR STATOR & ROTOR REWIND	1,014,768
23	PROJECTS LESS THAN $1 MILLION	65,221,766
24	TOTAL PRODUCTION PLANT $973,152,017	
25		
26	TRANSMISSION PLANT	
27		
28	OAKBORO BANK 4 ADDITION	12,521,846
29	MCGUIRE UNIT 1B MAIN STEP UP TRANSFORMER	11,107,468
30	MCGUIRE SWITCHYARD TRANSFORMER	10,182,494
31	TOWN CREEK NETWORK TO WESTLAKE	9,181,466
32	ANTIOCH TIE STATION TRANSFORMER BANK INSTALLATION	9,011,601
33	RURAL HALL TIE STATIC VAR COMPENSATOR	7,864,285
34	OCONEE 230KV PCB	7,044,119
35	CATAWBA SECURITY ENHANCEMENT	6,989,787
36	E SPARTANBURG TIE - INSTALL ALL NEW RELAYING AND CONTROL HOUSE	6,471,371
37	HENDERSONVILLE MAIN TIE LINE REBUILD	6,331,536
38	OPGW - ALBRIGHT 230KV LINES	5,963,493
39	ORCHARD TIE - BUILD A 230KV TO 100KV STATION	5,544,489
40	WOODLAWN TIE SECURITY ENHANCEMENT	5,032,554
41	ROCKFORD 44KV LINE	4,962,051
42	NEWPORT TIE SECURITY ENHANCEMENT	4,802,854
43	TOTAL	1,632,658,461

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	OPGW - FAGO 230KV LINES	4,528,866
2	MARSHALL STEAM SECURITY ENHANCEMENT	4,508,093
3	BU 20017 DEC TRANSMISSION SUBSTATIONS (FF) FUNDING PROJECT FOR ENABLE	4,483,128
4	NORTH GREENSBORO TIE BANK 4	4,184,547
5	HARRISBURG SECURITY ENHANCEMENT	4,090,009
6	BALLANTYNE - NEW SWITCHING STATION	4,057,442
7	WYLIE SECURITY ENHANCEMENT	3,904,273
8	BELAIR SWITCHING STATION	3,363,699
9	TIGER DOUBLE CIRCUIT LINES FROM LELIA TO WALDEN	3,088,809
10	OPGW - HARRISBURG 230KV LINES	2,598,229
11	BU 20017 DEC TRANSMISSION LINES (GG) FUNDING PROJECT FOR ENABLE	2,271,750
12	OCONEE 525KV BUS DIFF	2,227,087
13	OPGW - NEUSE 230KV LINES	2,097,903
14	DAN RIVER WRAP UP: SITE PERIMETER FENCE, DRAINAGE MODS, BELOW GRADE DEMO, AND	1,936,133
15	ABBOTTS CREEK TIE P&C STATION	1,830,265
16	PLEASANT GARDEN 525KV BREAKERS	1,648,345
17	CLINTON TIE - BREAKER	1,546,218
18	SOUTH CAROLINA TRANSMISSION LINE INSULATOR - POLYMER	1,383,379
19	SHADY GROVE TIE TRANSFORMER COOLER	1,332,766
20	NORTH CAROLINA TRANSMISSION LINE INSULATOR - POLYMER	1,326,349
21	MITCHELL RIVER SERIES BJB	1,303,947
22	OPGW MARSHALL TO MCGUIRE - NEW 48 FIBER	1,279,444
23	NTE TRANSMISSION STATIONS	1,261,941
24	NEW CIRCUIT BREAKERS FOR WINSTON LINES ARE BECKERDITE	1,217,220
25	OXFORD HYDRO SPCC BREAKER	1,201,130
26	RURAL HALL SECURITY ENHANCEMENT	1,158,477
27	MARSHALL STEAM SWITCHYARD GAS BREAKERS	1,077,998
28	WEST FRANKLIN TO NORTH FRANKLIN 66 KV LINE - PHASE 4	1,068,543
29	DEATH VALLEY NEW SUBSTATION	1,065,582
30	PROJECTS LESS THAN $1 MILLION	46,743,780
31	TOTAL TRANSMISSION PLANT $226,796,766	
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	1,632,658,461

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

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	14,828,830,111	14,828,830,111		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,029,546,198	1,029,546,198		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,353,431	1,353,431		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	84,081,201	84,081,201		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,114,980,830	1,114,980,830		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	591,681,866	591,681,866		
13	Cost of Removal	162,221,849	162,221,849		
14	Salvage (Credit)	45,756,192	45,756,192		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	708,147,523	708,147,523		
16	Other Debit or Cr. Items (Describe, details in footnote):	85,950,841	85,950,841		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	15,321,614,259	15,321,614,259		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	3,470,098,363	3,470,098,363		
21	Nuclear Production	3,388,788,839	3,388,788,839		
22	Hydraulic Production-Conventional	355,662,486	355,662,486		
23	Hydraulic Production-Pumped Storage	622,914,307	622,914,307		
24	Other Production	873,961,582	873,961,582		
25	Transmission	1,385,390,867	1,385,390,867		
26	Distribution	4,816,027,629	4,816,027,629		
27	Regional Transmission and Market Operation				
28	General	408,770,186	408,770,186		
29	TOTAL (Enter Total of lines 20 thru 28)	15,321,614,259	15,321,614,259		

Schedule Page: 219 Line No.: 8 Column: c

ARO Depreciation Deferral	$74,607,951
Cliffside	($511,125)
Dan River	($149,274)
Defer depr expense on SC AMI meter	$5,214,020
McGuire Oconee	($86,084)
NPL WWII assets	($75,977)
Reclass expense on in service meters	($759,116)
Renewables	$227,889
RFS Amortization	($282,270)
SC Electronic Data Processing	$1,548,524
TEP	$603,770
Buck and Bridgewater	($24,416)
Mocksville and Monroe	$443,615
ABSAT Depr Deferral	$2,473,959
Buck 5&6/Riverbend Inventory - offset 0186700	($335,367)
Unrecovered Buck Costs - NC	($7,577,672)
SC Depr Deferral	$3,790,842
Buck, Bridgewater	($122,080)
NC Transmission Depr	$59,963
Grid Modernization Deferral	$366,385
CWDC Depr Deferral	$945,763
NC Lee CC Depr Deferral	$3,818,968
SC Lee CC Depr Deferral	$3,111,325
Lee CC Budgeted Deferral	($1,333,365)
Amort of Rotable Fleet Spare Reg Asset and Liab	($1,656,105)
NC Lee CC Deferral Amortization	($218,923)
Total	$84,081,201

Schedule Page: 219 Line No.: 16 Column: c

NBV of Retired NC/SC Meters to Reg Asset	(29,772,554)
Gain/Loss to Footnote	156,471
Transfers and Adjustments to Footnote	115,566,924
Total	85,950,840

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

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			
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	Total Cost of Account 123.1 $ 0		TOTAL	13,114,070

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	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	13,114,081		42

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)	229,301,332	220,760,888	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	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	555,915,158	212,345,132	Electric
8	Transmission Plant (Estimated)	49,052,803	7,860,493	Electric
9	Distribution Plant (Estimated)	92,574,165	16,741,171	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)	697,542,126	682,226,291	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	71,125	103,378	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	44,420,013	45,188,768	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	971,334,596	948,279,325	

Schedule Page: 227 Line No.: 5 Column: c

5. Assigned To Construction

Production	$337,122,879
Transmission	36,305,042
Distribution	71,851,574
Total	$445,279,495

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	1,167,068.00	429,570	137,539.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	3,042.00			
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	18,912.00	4,202		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	1,151,198.00	425,368	137,539.00	
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)		125		
45	Gains		125		
46	Losses				

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.

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
138,060.00		138,236.00		3,587,331.00		5,168,234.00	429,570	1
								2
								3
				138,236.00		141,278.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						18,912.00	4,202	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
138,060.00		138,236.00		3,725,567.00		5,290,600.00	425,368	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
					41		166	44
					41		166	45
								46

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.: 1 Column: d

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 $17,165,794 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 Pollution Rule and the Acid Rain Program.

Schedule Page: 228 Line No.: 29 Column: d

Ending balance includes allowances for Cross State Air Pollution Rule and the Acid Rain Program.

Schedule Page: 228 Line No.: 29 Column: m

Does not include the $45,738,290 for renewable energy credits represented in account 0158120.

Schedule Page: 228 Line No.: 39 Column: b

Represents allowances withheld in 2018 sold at auction.

Schedule Page: 228 Line No.: 44 Column: m

Represents 2018 SO2 EPA Auction proceeds.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	30,525.00	5,279		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,174.00		22,383.00	
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	20,573.00			
19	Other:				
20		333.00			
21	Cost of Sales/Transfers:				
22	Sales (see notes)	200.00	604		
23					
24					
25					
26					
27					
28	Total	200.00	604		
29	Balance-End of Year	10,593.00	4,675	22,383.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		40,000		
34	Gains		39,396		
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				

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.

2020 No. (f)	2020 Amt. (g)	2021 No. (h)	2021 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
						30,525.00	5,279	1
								2
								3
19,124.00		19,124.00		19,124.00		80,929.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						20,573.00		18
								19
						333.00		20
								21
						200.00	604	22
								23
								24
								25
								26
								27
						200.00	604	28
19,124.00		19,124.00		19,124.00		90,348.00	4,675	29
								30
								31
								32
							40,000	33
							39,396	34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 18 Column: c

Does not include the $17,165,794 for renewable energy credits consumption expense represented in account 0509213.

Schedule Page: 229 Line No.: 22 Column: a

Counterparty	Quantity	COGS	Gain on Sale
Dynegy Marketing and Trade, LLC	200	$604	$39,396
	200	$604	$39,396

Schedule Page: 229 Line No.: 29 Column: c

Does not include the $45,738,290 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	5,351	0561600		
3	DEC - Newberry Solar - SIS	261	0561600		
4	Jonesville - SIS	198	0561600		
5	Ft Lawn - SIS	465	0561600		
6	Oakboro - SIS	312	0561600		
7	Bailybead Solar - FEA	660	0561600		
8	Westminister Solar - FEA	1,117	0561600		
9	Perini Solar - FEA	247	0561600		
10	Princeton Solar - FEA	171	0561600		
11	Broad River - SIS	592	0561600		
12	Quail Holding - FEA	394	0561600		
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	State Studies	(10,390)	0561700		
23	Hereford - SIS	(2,664)	0561700		
24	Lancaster Solar	236	0561700		
25	Pheonix - SIS	(647)	0561700		
26	Birdseye Hereford - FAC	(762)	0561700		
27	Clemson CHP - SIS	(835)	0561700		
28	Birdseye Simmental - FAC	(2)	0561700		
29	Gaston - FAC	46	0561700		
30	Lincoln CT- FAC	21	0561700		
31	Fresh Air Energy - SIS	251	0561700		
32	Yorkshire Holding - SIS	492	0561700		
33	Fresh Air Energy - FEA	320	0561700		
34	Fresh Air Energy II - FEA	726	0561700		
35	New Town - FEA	214	0561700		
36	Mill Creek - FEA	356	0561700		
37	Iron Works - FEA	2,483	0561700		
38	Pittsburg - FEA	2,044	0561700		
39	Richfield - FEA	841	0561700		
40	Bradley Ecoplexus - FEA	2,074	0561700		

Transmission Service and Generation Interconnection Study Costs (continued)

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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Roughedge Ecoplexus - FEA	1,493	0561700		
23	Kannapolis Ecoplexus - FEA	1,245	0561700		
24	Oakboro Ecoplexus - FEA	(226)	0561700		
25	Clemson CHP - FAC	(5,358)	0561700		
26	Clemson CHP - FEA	(1,685)	0561700		
27	Buck CC - FEA	(452)	0561700		
28	Mobjack Solar - FEA	4,346	0561700		
29	Birdseye Rutabaga - FEA	1,090	0561700		
30	Birdseye - Quail - FAC	484	0561700		
31	NC Bio Gas - FAC	263	0561700		
32	Perini Solar - FEA	421	0561700		
33	Princeton Solar - FEA	425	0561700		
34	Beefmaster Solar - FEA	1,638	0561700		
35					
36					
37					
38					
39					
40					

Transmission Service and Generation Interconnection Study Costs (continued)

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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	455,457,126	24,882,530	283/282	15,825,596	464,514,060
2						
3	Asset Retirement Obligation FAS 143					
4	PSC Docket No. 2003-84-E Order No. 2003-283					
5	NCUC Docket No. E-7 Sub 723					
6						
7	Vacation Accrual					
8	NCUC Docket No. E-7, Sub 774	83,027,990	197,856	242	4,932,858	78,292,988
9						
10	Extraordinary Repairs - Thorpe Rewind					
11	Amortized over 25 years					
12	NCUC Docket No. E-13, Sub 166	269,574		545	241,209	28,365
13						
14	Retail portion - IRS Section 124 Asset Depreciation	1,850,974		403	75,977	1,774,997
15						
16	Energy Efficiency Cost Recovery - NC					
17	NCUC Dockets No. E-7 Sub 1050	151,408,291	12,060,762	456	47,879,563	115,589,490
18						
19	Renewable Energy and Energy Portfolio					
20	Standard Cost Deferral					
21	NCUC Docket No. E-7, Sub 1052	2,690,936	8,565,585	Various	7,290,029	3,966,492
22						
23	Cliffside Deferral 5 Year Amortization					
24	NCUC Docket No. E-7 Sub 1026					
25	PSC Docket No. 2013-59-E					
26						
27	Pension Non-Qualified					
28	NCUC Docket No. E-100, Sub 112	4,484,411	423,500	Various	322,560	4,585,351
29						
30	Pension Qualified					
31	NCUC Docket No. E-100, Sub 112	405,380,658	191,965,419	Various	21,067,092	576,278,985
32	Settlement Agreement					
33						
34	Interest Rate Swap					
35	NCUC Docket E-7 Sub 1026					
36	PSC Docket 2013-59-E	75,013,148		431	3,136,438	71,876,710
37						
38	Natural Gas Hedging - MTM					
39	NCUC Docket E-2 Sub 939					
40	NCUC Docket E-2 Sub 1049					
41	NCUC Docket E-7 Sub 862					
42	NCUC Docket E-7 Sub 1006					
43	PSC Docket 2015-95-E	9,318,201	101,565,350	245	90,819,928	20,063,623
44	TOTAL	2,760,098,689	3,103,816,309		1,875,533,345	3,988,381,653

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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						
2	Pension Deferred Costs					
3	NCUC Docket E-7 Sub 989 - 5 Year Amortization					
4	PSC Order 2012-77 - 3 Year Amortization					
5						
6	Buck and Bridgewater Deferred Costs					
7	25 Year Amortization					
8	NCUC Docket E-7 Sub 999					
9	PSC Docket 2012-57-E	5,531,089	1,268,244	Various	1,634,208	5,165,125
10						
11	SC Energy Efficiency					
12	PSC Docket 2011-420-E	58,316,070	9,770,162	456	14,450,371	53,635,861
13						
14	Dan River & Cliffside 6 Deferred Costs					
15	Dan River - 39 Year Amortization - SC					
16	Dan River - 4 year Amortization - NC					
17	Cliffside 6 - 35 Year Amortization - SC					
18	Cliffside 6 - 4 year Amortization - NC					
19	PSC Docket 2013-99-E					
20	NCUC Docket E-7 Sub 1029	25,631,114	3,357,684	Various	4,147,271	24,841,527
21						
22	McGuire and Oconee Deferred Costs					
23	McGuire - 43 Year Amortization - SC					
24	McGuire - 4 Year Amortization - NC					
25	Oconee - 28 Year Amortization - SC					
26	PSC Docket: 2013-99-E					
27	NCUC Docket E-7 Sub 1029	3,880,158	579,780	Various	688,073	3,771,865
28						
29	Fukushima Cybersecurity Def- SC					
30	4 Year Amortization					
31	PSC Order 2013-59-E	7,346	26,639	Various	33,985	
32						
33	Nuclear Levelization					
34	18 -24 Months Amortization					
35	NCUC Docket E-7 Sub 1026					
36	PSC Docket 2013-59-E	83,575,860	257,705,127	Various	253,918,000	87,362,987
37						
38	Billing System Deferral					
39	NCUC Docket E-7 Sub 1026	656,028				656,028
40						
41	Rate Case Costs					
42	NCUC Docket No. E-7 Sub 909					
43	PSC Docket No. 2009-226-E					
44	TOTAL	2,760,098,689	3,103,816,309		1,875,533,345	3,988,381,653

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	NCUC Docket E-7 Sub 989					
2	PSC Docket No. 2011-271-E, Order No. 2012-77	2,635,349	6,538,038	928	706,895	8,466,492
3						
4	Coal Ash Basin - ARO Deferral					
5	NC Coal Ash Management Act of 2014					
6	Consent Agreement with SCDHEC	1,002,325,757	198,109,491	Various	305,139,647	895,295,601
7						
8	Coal Ash Remediation Costs					
9	PSC Docket No. 2016-196-E	198,221,876	418,094,475	407	252,543,986	363,772,365
10						
11	Deferred Fuel					
12	PSCSC Docket 2014-3-E	35,827,577	82,597,750	254/557	34,746,814	83,678,513
13						
14	Deferred Fuel					
15	NCUC Docket E-7 Sub 1033	104,749,280	173,890,701	254/557	166,537,549	112,102,432
16						
17	NCUC Regulatory Fee					
18	NCUC Docket M-100, Sub 142	2,624,093	788,579	921/182	231,422	3,181,250
19						
20	SC Distributed Energy Resource Program					
21	PSC Docket No. 2015-3-E	35,976,077	10,216,461	Various	6,798,468	39,394,070
22						
23	Rotable Fleet Spare					
24	NCUC Docket E-2, Sub 998A					
25	NCUC Docket E-7, Sub 986A					
26	PSC Docket 2015-293-E	1,964,006	2,683,434	403	2,959,479	1,687,961
27						
28	Advanced Metering Infrastructure					
29	PSC Docket No. 2016-240-E	9,275,700	134,401,970	421	11,227,146	132,450,524
30						
31	NC Coal Ash Spend					
32	NCUC Docket E-7, Sub 1146		555,232,377	186	89,390,753	465,841,624
33						
34	NC Customer Connect					
35	NCUC Docket E-7, Sub 1146		14,639,219	Various	341,338	14,297,881
36						
37	Lee COLA- NC Nuclear Retail Portion					
38	NCUC Docket E-7, Sub 1146		769,947,151	Various	504,801,458	265,145,693
39						
40	Lee Combined Cycle Deferrals					
41	NCUC Docket E-7, Sub 1146					
42	PSCSC Docket No. 2018-207-E, Order No. 2018-552		34,440,101	Various	17,475,737	16,964,364
43						
44	TOTAL	2,760,098,689	3,103,816,309		1,875,533,345	3,988,381,653

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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	Ash Basin Strategic Action Team (ABSAT)					
2	PSC Docket No. 2016-196-E, Order No. 2016-490					
3	NCUC Docket E-7, Sub 1146		14,944,336	Various	7,961,606	6,982,730
4						
5	Carolinas West Primary District Control Center (CW)					
6	PSC Docket No. 2018-207-E, Orde2		7,447,988	Various	5,072,705	2,375,283
7						
8	NC Solar Rebate Program					
9	NCUC Docket E-2, Sub 1167					
10	NCUC Docket E-7, Sub 1166		3,741,069	Various	237,906	3,503,163
11						
12	CPRE Rider					
13	NCUC Docket E-7, Sub 1170		1,685,710	Various	1,239,970	445,740
14						
15	NC Coal Inventory Rider					
16	NCUC Docket E-7, Sub 1146		91,560			91,560
17						
18	Cost of Removal Settlement					
19	NCUC Docket E-7, Sub 1146		57,996,000	407	850,880	57,145,120
20						
21	Grid Deferral					
22	PSC Docket No. 2018-206-E, OrderNo. 2018-519		3,877,028	Various	722,434	3,154,594
23						
24	Other Deferred Costs		84,233	Various	83,994	239
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	2,760,098,689	3,103,816,309		1,875,533,345	3,988,381,653

Schedule Page: 232 Line No.: 21 Column: d
'105,107,108,120,123,131,142,143,146,154,158,163,165,174,181,182,183,186,228,232,234,235,236,237,241,242,253,254,43,407,408,411,417,419,421,426,447,450,454,456,500,501,502,506,509,510,511,514,517,518,519,520,523,524,528,529,530,531,532,539,543,546,549,550,551,553,555,557,561,565,566,570,588,593,804,903,909,,910,912,920,921,923,924,925,926,928,930,931,935

Schedule Page: 232 Line No.: 28 Column: d
128,228,253,254,926

Schedule Page: 232 Line No.: 31 Column: d
'128, 228, 253, 254, 926, 146, 186

Schedule Page: 232.1 Line No.: 9 Column: d
'403, 407, 408, 421, 431, 510, 546

Schedule Page: 232.1 Line No.: 20 Column: d
'403, 407, 408, 421, 431, 510

Schedule Page: 232.1 Line No.: 27 Column: d
'403, 407, 421, 431

Schedule Page: 232.1 Line No.: 31 Column: d
421,431,524

Schedule Page: 232.1 Line No.: 36 Column: d
'520, 524, 528, 530, 531, 532, 921, 517, 519, 523, 529, 513, 930, 570, 588, 926, 506, 528

Schedule Page: 232.2 Line No.: 6 Column: d
'403, 411, 254, 230

Schedule Page: 232.2 Line No.: 21 Column: d
'146,1825,107,232,236,242,557,912,930,186,142,235,426,450,921,923,253,903,181,561,569,228,143,456,407,555,910,920,417,593

Schedule Page: 232.2 Line No.: 35 Column: d
'431,408,902,903,921,923,926,528,566,581,588,903,910,920,921,926,935,912

Schedule Page: 232.2 Line No.: 38 Column: d
'407,421,107,426,105,186

Schedule Page: 232.2 Line No.: 42 Column: d
'921,403,408,421,431,506,510,513,546,547,548,549,551,552,553,554,903,930,548

Schedule Page: 232.3 Line No.: 3 Column: d
'403,421,431

Schedule Page: 232.3 Line No.: 6 Column: d
'403,404,421,431

Schedule Page: 232.3 Line No.: 10 Column: d
'105,107,108,120,131,142,143,146,154,163,181,182,183,184,186,228,232,235,236,241,242,253,408,417,421,426,431,450,500,501,502,506,510,511,514,517,518,519,520,523,524,528,529,530,531,532,543,546,553,555,557,561,569,570,588,593,804,903,909,910,912,920,921,923,925,926,930,931,935

Schedule Page: 232.3 Line No.: 13 Column: d
'105,107,108,120,142,146,154,163,182,183,184,186,228,232,236,241,242,253,408,417,419,426,50,502,506,510,514,517,518,519,520,523,524,528,529,530,531,543,546,553,561,570,588,593,804,903,910,912,920,921,923,925,926,930,935

Schedule Page: 232.3 Line No.: 22 Column: d
'403,421,431

Schedule Page: 232.3 Line No.: 24 Column: d
'105,107,108,120,142,143,146,154,163,182,183,184,186,228,232,236,241,242,253,408,417,421,426,500,502,506,510,511,514,517,518,519,520,523,524,528,529,530,531,532,537,543,546,553,555,561,570,588,593,804,903,910,912,920,921,923,924,925,926,930,931,935

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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Demand Side Management Costs	-4,190,977	138,571	Various	762,525	-4,814,931
2						
3	Storm Costs		404,747,350	Various	256,836,999	147,910,351
4						
5	Renewables	-1,224,223	1,306,685	182,186	2,431,705	-2,349,243
6						
7	I & D Insurance Receivable	585,054,561	187,144,078	Various	32,748,363	739,450,276
8						
9	Coal Ash Remediation Costs	444,535,237	259,052,090	Various	703,587,327	
10						
11	Meter Retirement Costs	29,300,495		182	29,300,495	
12						
13	Lee COLA - SC Retail Portion		122,360,416	186,426	28,762,855	93,597,561
14						
15	Lee COLA - Wholesale Portion		48,071,067	186,426	24,035,533	24,035,534
16						
17	Equity Return on BPM Sharing	1,006,453	60,633	421	375,786	691,300
18						
19	Pension/OPEB - Post Retirement	211,162		182	211,162	
20						
21	Combustion Turbine Generator	14,226,027				14,226,027
22						
23	Retired Plant Cost	29,305,153		403,182	7,913,039	21,392,114
24						
25	Pooled Inventory	4,534,508				4,534,508
26						
27	Costs Removal Retail Mitigation	102,794,000	3,799,012	407	58,004,170	48,588,842
28						
29	Miscellaneous	39,098	49,908,780	Various	49,849,548	98,330
30						
31	Natural Gas Pipeline Upgrade		736,917	Various		736,917
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	340,195				1,092,095
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)	2,794,826	7,125,508	Various	7,647,077	2,273,257
49	TOTAL	1,208,726,515				1,091,462,938

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	2,492,302,268	2,697,261,240
8	TOTAL Electric (Enter Total of lines 2 thru 7)	2,492,302,268	2,697,261,240
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)	2,492,302,268	2,697,261,240

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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				
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				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

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 AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						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
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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, 2018	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	5.25% First Mortgage Bonds	400,000,000	2,097,525
29			1,360,000 D
30			
31	6.00% First Mortgage Bonds	500,000,000	4,109,714
32			350,000 D
33	TOTAL	12,124,306,557	113,241,931

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	5.10% First Mortgage Bonds	300,000,000	1,441,959
3			441,000 D
4			
5	6.05% First Mortgage Bonds	600,000,000	4,686,704
6			1,650,000 D
7			
8	7.00% First Mortgage Bonds	500,000,000	2,414,008
9			1,450,000 D
10			
11	5.3% First Mortgage Bonds	750,000,000	5,993,147
12			3,202,500 D
13			
14	4.3% First Mortgage Bonds	450,000,000	2,112,010
15			1,057,500 D
16			
17	3.9% First Mortgage Bonds	500,000,000	2,780,050
18			510,000 D
19			
20	4.25% First Mortgage Bonds	650,000,000	5,297,322
21			1,098,500 D
22			
23	4.00% First Mortgage Bonds	650,000,000	5,556,082
24			5,174,000 D
25			
26	3.70% First Mortgage Bonds	550,000,000	4,637,612
27			803,000 D
28			
29	3.05% First Mortgage Bonds	500,000,000	2,191,354
30			585,000 D
31			
32	3.95% First Mortgage Bonds	500,000,000	4,192,354
33	TOTAL	12,124,306,557	113,241,931

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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			2,365,000 D
2			
3	3.35% First Mortgage Bonds	350,000,000	345,641
4			129,500 D
5			
6	3.95% First Mortgage Bonds	650,000,000	616,190
7			2,398,500 D
8			
9	Bonds issued through Medium Term Notes Facility:		
10	Accounts 222 and 223:		
11	--		
12	Duke Energy Corporation - 2.7932%	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			
26	Other Long Term Debt	465,112,532	2,918,863
27			
28			
29			
30			
31			
32			
33	TOTAL	12,124,306,557	113,241,931

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	9,011,177	834,751	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	01/15/2018	01/2008	01/2018		816,667	28
						29
						30
01/10/2008	01/15/2038	01/2008	01/2038	500,000,000	30,000,000	31
						32
				10,907,272,747	473,780,172	33

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
04/14/2008	04/15/2018	04/2008	04/2018		4,420,000	2
						3
						4
04/14/2008	04/15/2038	04/2008	04/2038	600,000,000	36,300,000	5
						6
						7
11/17/2008	11/15/2018	11/2008	11/2018		30,527,778	8
						9
						10
11/16/2009	02/15/2040	11/2009	02/2040	750,000,000	39,750,000	11
						12
						13
06/02/2010	06/15/2020	06/2010	06/2020	450,000,000	19,350,000	14
						15
						16
05/19/2011	06/15/2021	05/2011	06/2021	500,000,000	19,500,000	17
						18
						19
12/08/2011	12/15/2041	12/2011	12/2041	650,000,000	27,625,000	20
						21
						22
09/21/2012	09/30/2042	09/2012	09/2042	650,000,000	26,000,000	23
						24
						25
11/14/2017	12/01/2047	11/2017	12/2047	550,000,000	20,350,000	26
						27
						28
03/01/2018	03/15/2023	03/2018	03/2023	500,000,000	12,708,333	29
						30
						31
03/01/2018	03/15/2048	03/2018	03/2048	500,000,000	16,458,333	32
				10,907,272,747	473,780,172	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
11/08/2018	05/15/2022	11/2018	05/2022	350,000,000	1,726,181	3
						4
						5
11/08/2018	11/15/2028	11/2018	11/2028	650,000,000	3,779,931	6
						7
						8
						9
						10
						11
10/2008	2099			300,000,000	16,249,127	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	3,132,281	19
						20
09/01/2010	11/01/2040	09/2010	11/2040	50,000,000	2,312,500	21
						22
09/01/2010	11/01/2040	09/2010	11/2040	50,000,000	2,312,500	23
						24
						25
				455,061,570	17,094,071	26
						27
						28
						29
						30
						31
						32
				10,907,272,747	473,780,172	33

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, 2018.

Schedule Page: 256.2 Line No.: 26 Column: a

The Other Long Term Debt ending balance includes gains on cancelled swaps of $5.1 million as of December 31, 2018. The 2018 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	1,070,378,654
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	721,734,326
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	348,644,328
28	Show Computation of Tax:	
29		
30	21% of $348,644,328	73,215,310
31	Prior Year Federal Tax Adjustments - Primarily Prior Year Tax True-Ups	-81,692,100
32		
33		
34	Total Federal Income Tax	-8,476,790
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 20 Column: b

AFUDC Equity Income	73,017,943
AFUDC Interest	35,192,184
Benefits Accruals	(178,329,529)
Book Depreciation	(1,658,451,403)
Charitable Contributions Accruals	11,438,119
Coal Ash Spend, Net of Capitalized Portion	132,953,318
Contributions in Aid of Construction	(24,612,134)
Deferred Fuel Asset	100,928,820
End of Life Nuclear Fuel Cost Reserve	(16,880,597)
Equipment/T&D Repairs	262,165,000
Injuries & Damages Accrual	10,400,161
Investment Tax Credit Amortization	5,258,630
Lawsuit Contingency	21,854,472
Lee COLA Impairment	390,442,637
Long Term Capital Lease Obligation	(48,418,541)
Loss on Reacquired Debt	(6,441,077)
Meals & Entertainment	(5,400,000)
Non-Qualified Nuclear Decommissioning Contributions/Earnings	(2,930,126)
Nuclear Fuel Book Burned	(275,311,826)
Nuclear Insurance Reserve	(8,676,301)
Other	175,296
Provision for Current Federal Income Taxes	8,476,790
Provision for Current State Income Taxes	3,916,518
Provision for Deferred Income Taxes	(308,685,380)
Rate Refunds	(69,670,981)
Regulatory Asset - ABSAT	6,982,730
Regulatory Asset - AMI/Non-AMI Meters	93,874,329
Regulatory Asset - Customer Connect	14,297,882
Regulatory Asset - CWDC Deferred Costs	2,375,283
Regulatory Asset - Deferred Plant Costs	(9,172,890)
Regulatory Asset - Energy Efficiency	(40,499,010)
Regulatory Asset - FAS 158	177,430,753
Regulatory Asset - Grid Deferred Costs	3,154,594
Regulatory Asset - Lee CC Deferred Costs	16,964,365
Regulatory Asset - Nuclear Levelization	3,787,127
Regulatory Asset - Rate Case Expenses	5,309,575
Renewable Energy Liability	(24,113,919)
Section 263A Adjustment	63,000,000
Self Developed Software	41,046,757
Severance Accrual	(95,532,755)
Storm Cost Deferral	147,438,884
Storm Cost Reserves	32,518,100
Tax Depreciation	1,667,626,950
Tax Gain/Loss (Cost of Removal)	191,534,532
Tax Interest Accrual	25,171,498
Tax Interest Capitalized	(53,872,452)
Total	721,734,326

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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	2,970,754		18,450,401	18,820,332	-311,213
5	Unemployment	8,902		91,942	98,655	
6	Miscellaneous			180,894	180,894	
7	Income taxes	16,621,616		2,083,590	4,438,845	-16,167,151
8						
9	LOCAL					
10	Property 2018	19,644,803	3,608,974	92,725,162	86,752,232	661,478
11						
12						
13						
14	SOUTH CAROLINA					
15	STATE					
16	Franchise	3,110,622		5,293,367	4,311,305	-3,025,070
17	Unemployment	2,591		296,120	297,316	
18	Kilowatt hour	653,510		9,701,369	9,701,369	
19	Miscellaneous			864	864	
20	Income Taxes	17,191,385		4,511,339	2,441,073	-15,387,720
21						
22	LOCAL					
23	Property 2018	115,317,006		117,558,333	116,090,451	-445,276
24						
25						
26	OTHER STATES					
27	Unemployment	228		18,425	17,419	
28						
29	FEDERAL					
30	Social Security	11,915,282		50,608,156	53,019,731	-92,495
31	Unemployment	4,982		285,900	119,347	-163,720
32	Highway Use			82,214	82,214	
33	Income taxes	44,743,009		-8,476,790	93,628,744	63,658,969
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	232,184,690	3,608,974	293,411,286	390,000,791	28,727,802

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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
2,289,610		18,450,401				4
2,189		91,942				5
		180,894				6
-1,900,791		2,392,030			-308,441	7
						8
						9
26,228,959	3,558,722	89,665,699			3,059,463	10
						11
						12
						13
						14
						15
1,067,614		5,293,367				16
1,395		296,120				17
653,510		9,701,369				18
		761			103	19
3,873,932		4,666,680			-155,340	20
						21
						22
116,339,611		117,154,173			404,160	23
						24
						25
						26
1,234		18,425				27
						28
						29
9,411,212		50,608,156				30
7,815		285,900				31
		82,214				32
6,296,444		-3,506,659			-4,970,131	33
						34
						35
						36
						37
						38
						39
						40
164,272,734	3,558,722	295,381,472			-1,970,186	41

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 3%. 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 valorem) taxes are charged to a central business unit 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 - 6,795,164 excluded from Balance At Beginning Of Year(column b)
Sales and Use Tax Payable - 6,154,539 excluded from Balance At End Of Year (column g)

Schedule Page: 262 Line No.: 4 Column: f

Offset to account 186	$(441,567)
Offset to account 253	130,354
Total	$(311,213)

Schedule Page: 262 Line No.: 7 Column: f

Offset to account 146

Schedule Page: 262 Line No.: 10 Column: f

Offset to account 131	$796,485
Offset to account 151	132,973
Offset to account 182	59,752
Offset to account 253	(46,210)
Offset to account 419	(281,522)
Total	$661,478

Schedule Page: 262 Line No.: 16 Column: f

Offset to account 146	$(2,369,712)
Offset to account 190	(655,358)
Total	$(3,025,070)

Schedule Page: 262 Line No.: 20 Column: f

Offset to account 146

Schedule Page: 262 Line No.: 23 Column: f

Offset to account 232

Schedule Page: 262 Line No.: 30 Column: f

Offset to account 182	$(155,396)
Offset to account 242	62,901
Total	$(92,495)

Schedule Page: 262 Line No.: 31 Column: f

Offset to account 242

Schedule Page: 262 Line No.: 33 Column: f

Offset to account 146	$63,429,594
Offset to account 190	137,625
Offset to account 254	91,750
Total	$63,658,969

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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	1,525,157			411.4	78,287	
4	7%						
5	10%	61,522,153			411.4	5,180,343	
6	15%	125,000,000					
7	30%	44,341,100	190	5,322,556			-1,082,517
8	TOTAL	232,388,410		5,322,556		5,258,630	-1,082,517
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	TOTAL						
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
1,446,870			3
			4
56,341,810			5
125,000,000			6
48,581,139			7
231,369,819			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Schedule Page: 266 Line No.: 5 Column: b

0182399
0128811
0128813
0128810
0128812

Schedule Page: 266 Line No.: 6 Column: b

0228315
0926000
0926999

Schedule Page: 266 Line No.: 7 Column: b

142802
174015
176001
182321
232181
245001
245002

Schedule Page: 266 Line No.: 7 Column: d

Eligible 30% ITC for expenditures for the Bear Creek Hydro, Cowans Ford Hydro, and Oxford Hydro upgrades. Placed in service date 2017.

Schedule Page: 266 Line No.: 7 Column: g

The deferral of $35,550,000 reported for 2017 represented an estimate of the 30% ITC for the Monroe Solar project. During 2018, the 2017 Federal Tax Return was filed and the actual amount of the credit was $33,954,994, which was $1,595,006 lower than originally estimated.

On the 2017 Federal Tax Return there was $512,489 of additional 30% ITC claimed related to the Mocksville Solar project. Mocksville was originally reported on the 2016 FERC Form 1, pages 266-267, and then adjusted on the 2017 pages.

Monroe Solar adjustment	$ (1,595,006)
Mocksville Solar adjustment	$ 512,489
Total adjustments	$ (1,082,517)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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	Decommissioning Costs -					
2	Externally Funded	451,509,880	0128	81,389,055	55,047,218	425,168,043
3						
4	Prepaid Extra Facilities Lighting	15,344,341	Various	6,948,007	6,069,637	14,465,971
5						
6	Merger Related Charitable	23,800,000	0131	11,900,000		11,900,000
7	Contributions					
8						
9	Deferred Income Tax - NC Rate	83,685,882	Various		3,317,363	87,003,245
10	Change					
11						
12	Catawba - Wateree relicensing	8,504,399	Various	1,568,428	520,898	7,456,869
13	future projects and Misc					
14						
15	Manufactured Gas Plants	8,156,000	0131,0426	1,015,197	734,197	7,875,000
16	Reserve					
17						
18	Other	18,160,667	Various	16,227,803	17,590,190	19,523,054
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						
45						
46						
47	TOTAL	609,161,169		119,048,490	83,279,503	573,392,182

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	CHANGES DURING YEAR: 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		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)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	4,129,591,930	758,473,964	506,241,442
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	4,129,591,930	758,473,964	506,241,442
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	4,129,591,930	758,473,964	506,241,442
10	Classification of TOTAL			
11	Federal Income Tax	3,668,030,602	663,289,538	438,889,188
12	State Income Tax	461,561,328	95,184,426	67,352,254
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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
8,448,638	789,935		51,115,738	182	4,825,522	4,343,192,939	2
							3
							4
8,448,638	789,935		51,115,738		4,825,522	4,343,192,939	5
							6
							7
							8
8,448,638	789,935		51,115,738		4,825,522	4,343,192,939	9
							10
7,372,217	689,762		38,122,086		4,761,591	3,865,752,912	11
1,076,421	100,173		12,993,652		63,931	477,440,027	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: h

253 - North Carolina Excess Deferred Income Taxes	$2,301,182
254 - North Carolina Excess Deferred Income Taxes	6,528,996
254 - Federal Excess Deferred Income Taxes	42,285,530
190-283 - Tax Basis Balance Sheet Adjustment	30
Total	$51,115,738

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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		1,776,438,934	602,188,980	240,429,945
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,776,438,934	602,188,980	240,429,945
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)	1,776,438,934	602,188,980	240,429,945
20	Classification of TOTAL			
21	Federal Income Tax	1,549,820,627	530,968,772	211,700,690
22	State Income Tax	226,618,307	71,220,208	28,729,255
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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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					
		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)	Balance at End of Year (k)	Line No.
							1
							2
	44,204,257	253,254	54,981,799	146,182	4,245,229	2,043,257,142	3
							4
							5
							6
							7
							8
	44,204,257		54,981,799		4,245,229	2,043,257,142	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
	44,204,257		54,981,799		4,245,229	2,043,257,142	19
							20
	38,572,298		51,543,142		3,690,770	1,782,664,039	21
	5,631,959		3,438,657		554,459	260,593,103	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: h

253 - North Carolina Excess Deferred Income Taxes	$706,300
254 - North Carolina Excess Deferred Income Taxes	2,010,239
254 - Federal Excess Deferred Income Taxes	52,265,260
Total	$54,981,799

Schedule Page: 276 Line No.: 3 Column: j

146 - Intercompany Transactions	$11,943
182 - Regulatory Assets	4,233,286
Total	$4,245,229

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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					
2	NCUC Docket No. E-7, Sub 1026					
3	SCPSC Docket 2013-59-E	79,667,327	Various	104,396,469	103,473,456	78,744,314
4						
5	NC Tax Rate Change					
6	NCUC Docket No. M-100, Sub 138	235,579,869	Various	206,967,818	194,437,270	223,049,321
7						
8	Settlement give back	14,515,333		14,515,333		
9	NCUC Docket No E-7 Sub 1051	45,724,732	557	352,447,561	306,722,829	
10						
11	ARO Regulatory Liability	344,921,106	Various	536,549,913	268,702,840	77,074,033
12	NCUC Docket No E-7 Sub 723					
13	SCPSC Docket No 2003-84-E					
14						
15	I & D Regulatory Liability					
16	NCUC Docket No E-7, Sub 1026					
17	SCPSC Docket 2013-59-E	30,785,968			2,752,658	33,538,626
18						
19	NC REC Liability	62,411,040	557	30,969,177	37,917,302	69,359,165
20	NCUC Docket E-7, Sub 1052					
21						
22	SC Storm Reserve Fund					
23	SCPSC Docket 2013-59-E	20,170,830		64,374,450	31,856,350	-12,347,270
24						
25	OPEB Liability	44,428,674	Various	6,665,946		37,762,728
26	FERC Docket No. AI07-1-000					
27	Reg Liability-NQ - FAS 106 - Medical	58,406	926	5,632	8,876	61,650
28						
29	NDTF Contaminated Liability					
30	NCUC Docket No E-7 Sub 723					
31	SCPSC Docket No 2003-84-E	460,505,258				460,505,258
32						
33	End of Life Reserves	78,072,500	407	3,061,667	19,942,264	94,953,097
34	NCUC Docket No. E-7, Sub 1026					
35						
36	NDTF Giveback					
37	NCUC Docket No. E-100 Sub 56					
38	PSC Docket No.2015-96-E					
39	NC Long-Term Liab					
40	SC Long-Term Liab Defer Fuel					
41	TOTAL	4,571,153,903		70,885,038,787	70,615,599,127	4,301,714,243

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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						
2	NC Unbilled Fuel Giveback					
3	NCUC Docket No. E-7, Sub 1051					
4						
5	Mark to Market Fuel - LT	159,579	Various	43,118,791	43,502,061	542,849
6						
7	SC Unbilled Fuel					
8	PSCSC Docket 2014-3-E					
9						
10	Reg Liab - Excess Fed ADIT - NC Retail	3,154,153,281	Various	35,468,645,084	*,***,***,***	1,666,438,970
11						
12	Excess Fed ADIT - Wholesale			90,698,577	316,651,147	225,952,570
13						
14	PSC Docket 2013-59-E					
15						
16	Interest Rate Swap - ST		175	5,246,048	5,246,048	
17						
18	Excess ADIT Grossup LT			33,596,153,607	*,***,***,***	751,310,033
19						
20	Reg Liab - Fed EDIT - SC Retail			230,409,974	804,275,804	573,865,830
21						
22	Interest Rate Swap Reg Liability			130,812,740	149,148,464	18,335,724
23						
24	Reg Liab - D&E Ret on St EDIT		Various		2,567,345	2,567,345
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	4,571,153,903		70,885,038,787	70,615,599,127	4,301,714,243

Schedule Page: 278 Line No.: 3 Column: c

0411101
0282101
0190002
0282100
0190001
0411100

Schedule Page: 278 Line No.: 6 Column: c

0190001
0190002

Schedule Page: 278 Line No.: 11 Column: c

0182399
0128811
0128813
0128810
0128812

Schedule Page: 278 Line No.: 25 Column: c

0228315
0926000
0926999

Schedule Page: 278.1 Line No.: 5 Column: c

142802
174015
176001
182321
232181
245001
245002

Schedule Page: 278.1 Line No.: 10 Column: c

0411101
0282101
0190002
0282100
0190001
0411100

Schedule Page: 278.1 Line No.: 24 Column: c

0407398
0421032
0431011

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	3,045,387,976	2,743,777,629
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	2,303,046,264	2,217,977,416
5	Large (or Ind.) (See Instr. 4)	1,225,863,502	1,221,920,876
6	(444) Public Street and Highway Lighting	45,515,330	46,404,801
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	6,619,813,072	6,230,080,722
11	(447) Sales for Resale	612,313,814	555,060,872
12	TOTAL Sales of Electricity	7,232,126,886	6,785,141,594
13	(Less) (449.1) Provision for Rate Refunds	184,514,676	13,034,471
14	TOTAL Revenues Net of Prov. for Refunds	7,047,612,210	6,772,107,123
15	Other Operating Revenues		
16	(450) Forfeited Discounts	20,000,193	18,368,585
17	(451) Miscellaneous Service Revenues	12,508,218	10,801,723
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	101,460,927	98,418,196
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-2,421,337	329,455,619
22	(456.1) Revenues from Transmission of Electricity of Others	94,204,325	86,079,787
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	225,752,326	543,123,910
27	TOTAL Electric Operating Revenues	7,273,364,536	7,315,231,033

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

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
29,557,841	26,717,072	2,215,198	2,181,646	2
				3
29,547,014	28,493,825	357,880	353,856	4
21,623,383	21,922,218	6,176	6,239	5
305,007	302,180	17,193	15,375	6
				7
				8
				9
81,033,245	77,435,295	2,596,447	2,557,116	10
11,246,968	9,871,268	23	24	11
92,280,213	87,306,563	2,596,470	2,557,140	12
				13
92,280,213	87,306,563	2,596,470	2,557,140	14

Line 12, column (b) includes $ -32,577,374 of unbilled revenues.
Line 12, column (d) includes -365,989 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 17 Column: b

0451100- Misc Service Revenue	(12,509,098)
0451200- Generation Application Fee	881
	(12,508,217)

Schedule Page: 300 Line No.: 17 Column: c

0451100- Misc Service Revenue	(10,800,411.63)
0451200- Generation Application Fee	(1,310.92)
	(10,801,722.55)

Schedule Page: 300 Line No.: 21 Column: b

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

Schedule Page: 300 Line No.: 21 Column: c

Other Variable Revenues-Reg	(153,764.56)
I/C Joint Disp - trans NW Rev	(55,074.85)
Transmission Study Revenue	(11,401.33)
Other Transmission Revenue	(2,090,331.01)
Comp For Serv Oth JointOwner	(18,226,583.17)
NC Unbilled Fuel Clause Rev	(101,268,223.00)
NC Unbilled Fuel Emf	(46,568,922.00)
SC Unbilled Fuel Clause Rev	(57,988,899.00)
Wholesale Unbilled Fuel Clause	
SAW Deferred Revenue	(69,067,695.17)
SC SAW Deferred Revenue	(12,862,064.13)
other Electric Revenue	(1,601,984.13)
Gross Up-Contr In Aid of Const	(1,540,650.13)
Deferred Dsm Costs NC	(170,146.64)
Other Revenue Affiliate	(13,703,408.16)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)
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					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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	16,271,548	1,736,458,426	1,260,912	12,905	0.1067
2	RE - Res. Water Htr. & Space Cond	13,056,990	1,293,002,636	932,647	14,000	0.0990
3	RET - Res Water Htr & Space TOU					
4	RST - Residential Service TOU	4	357	2	2,000	0.0893
5	RB - Res. Service	77,497	8,774,871	5,576	13,898	0.1132
6	RT - Res. Service	57,085	4,926,842	2,222	25,691	0.0863
7	WC - Res. Service Controlled W-H	61,856	1,562,151	11,195	5,525	0.0253
8	ES - Energy Star	191,522	19,406,591	13,839	13,839	0.1013
9	OPERATING REVENUE	1	-19,289			-19.2890
10	Subtotal - Account 440	29,716,503	3,064,112,585	2,226,393	13,347	0.1031
11	Unbilled Alloc. - Residential	-158,662	-18,724,609			0.1180
12	Duplicate Customers			-11,195		
13	Total Residential	29,557,841	3,045,387,976	2,215,198	13,343	0.1030
14	G - General Service	3,589	60,939	85	42,224	0.0170
15	GA - General Service					
16	OPT - General Service	2,822,810	192,616,861	4,955	569,689	0.0682
17	OL - Outdoor Lighting	435,788	96,175,259	350,403	1,244	0.2207
18	BC - Bldg - Construction Service	20,756	3,500,691	10,261	2,023	0.1687
19	I - Industrial Service	2,806,396	219,243,554	4,705	596,471	0.0781
20	OPT - Industrial Service	7,061,055	370,702,782	496	14,235,998	0.0525
21	PG - Parallel Generation	3,124	690,758	5	624,800	0.2211
22	Industrial Service	18	10,742	2	9,000	0.5968
23	FL - Flood Lighting	174,127	24,111,631	47,041	3,702	0.1385
24	SG - (GEN) - Small General Ser					
25	SGS - Small General Service	5,908,300	659,411,365	314,487	18,787	0.1116
26	LGS - Large General Service	6,279,779	503,587,877	11,585	542,061	0.0802
27	S - UNMETERED STREET LIGHTS			4		
28	Yard Lighting					
29	OPTVG - General Service	13,289,485	795,507,730	16,177	821,505	0.0599
30	OPTVI - Industrial Service	9,887,428	550,037,938	1,109	8,915,625	0.0556
31	Water Heating					
32	HO-Hourly Pricing	2,468,706	115,049,428	35	70,534,457	0.0466
33	MP-Multiple Premises	215,246	11,573,861	45	4,783,244	0.0538
34	MFR-Miscellaneous Non-metered		73,812	108		
35	OPERATING REVENUE		581			
36	Subtotal - Account 442	51,376,607	3,542,355,809	761,503	67,467	0.0689
37	Duplicate Customers			-397,444		
38	Unbilled Alloc. - Commercial & In	-206,210	-13,446,043			0.0652
39	Total Commercial & Industrial	51,170,397	3,528,909,766	364,059	140,555	0.0690
40	PL - Street and Public Lighting	271,803	37,377,549	8,000	33,975	0.1375
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	TS - Traffic Signal - Safety Non	12,390	2,274,397	7,338	1,688	0.1836
2	GL - Governmental Lighting Servic	21,654	6,145,546	1,847	11,724	0.2838
3	NL - Standard Lighting Service	278	124,561	8	34,750	0.4481
4	Subtotal - Account 444	306,125	45,922,053	17,193	17,805	0.1500
5	Unbilled Alloc. - Pub St & Highwa	-1,118	-406,723			0.3638
6	Total Public Street and Highway	305,007	45,515,330	17,193	17,740	0.1492
7	Total Retail Unbilled Fuel Clause					
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	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

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).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 Classifi-cation	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	215	258	248
3	Blue Ridge Electric Membership					
4	Corporation	AD	315			
5	Central Electric Power Cooperative,Inc.	RQ	336	671	676	668
6	Central Electric Power Cooperative,Inc.	AD	336			
7	City of Concord	RQ	327	165	180	178
8	City of Concord	AD	327			
9	City of Kings Mountain	RQ	331	23	28	28
10	City of Kings Mountain	AD	331			
11	City of Greenwood, SC	RQ	334	60	57	55
12	City of Greenwood, SC	AD	334			
13	Haywood Electric Membership Corporation	RQ	335	22	27	24
14	Haywood Electric Membership Corporation	AD	335			
	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 Classifi-cation	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	Lockhart Power Company	RQ	332	41	63	62
2	Lockhart Power Company	AD	332			
3	North Carolina Electric Membership					
4	Corporation	RQ	326	60	62	58
5	North Carolina Electric Membership					
6	Corporation	AD	326			
7	North Carolina Municipal Power Agency 1	OS	318			
8	North Carolina Municipal Power Agency 1	AD	318			
9	Piedmont Electric Membership					
10	Corporation	RQ	316	86	91	85
11	Piedmont Electric Membership					
12	Corporation	AD	316			
13	Piedmont Municipal Power Agency	RQ	340	47		
14	Piedmont Municipal Power Agency	AD	340			
	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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) (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	Rutherford Electric Membership					
2	Corporation	RQ	317	215	281	277
3	Rutherford Electric Membership					
4	Corporation	AD	317			
5	Town of Dallas	RQ	328	14	14	14
6	Town of Dallas	AD	328			
7	Town of Due West	RQ	329	2	3	3
8	Town of Due West	AD	329			
9	Town of Forest City	RQ	330	19	22	22
10	Town of Forest City	AD	330			
11	Town of Highlands	RQ	337	8	10	9
12	Town of Highlands	AD	337			
13	Town of Prosperity	RQ	333	2	3	2
14	Town of Prosperity	AD	333			
	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	Western Carolina University	RQ	338	8	9	9
2	Western Carolina University	AD	338			
3	Broad River Energy, LLC	OS	4			
4	North Carolina Municipal Power Agency 1	OS	4			
5	Piedmont Municipal Power Agency	OS	4			
6	Southern Power Company - Rowan Plant	OS	4			
7	Southern Power Company -Cleveland Plant	OS	4			
8	North Carolina Electric Membership					
9	Corporation	OS	273			
10	Central Electric Power Cooperative,Inc.	OS	6	61		
11	EDF Trading North America, 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**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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) (a)	Statistical Classifi-cation (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 Carolina Electric & Gas Company	OS	5			
2	South Carolina Electric & Gas Company	OS	294			
3	South Carolina Public Service Authority	OS	293	700		
4	South Carolina Public Service Authority	AD	293			
5	Tennessee Valley Authority	OS	3			
6	The Energy Authority, Inc.	OS	5			
7	Brookfield Energy Marketing LP	OS	4			
8	City of Seneca, South Carolina	OS	4			
9	Eagle Energy Partners	OS	4			
10	Energy United Electric Membership					
11	Corporation	OS	4			
12	Exelon Generation Co., LLC	OS	4			
13	FPLEMT	OS	4			
14	Lockhart Power Company	OS	4			
	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 Classifi-cation	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	Macquarie Energy	OS	4			
2	Mercuria Energy American	OS	4			
3	Morgan Stanley Capital Group Inc.	OS	4			
4	NTE	OS	4			
5	North Carolina Electric Membership					
6	Corporation	OS	4			
7	North Carolina Municipal Power Agency 1	OS	4			
8	Piedmont Municipal Power Agency	OS	4			
9	Rainbow Energy	OS	4			
10	South Carolina Electric & Gas Company	OS	4			
11	South Carolina Public Service Authority	OS	4			
12	Southern Power Company	OS	4			
13	Tennessee Valley Authority	OS	4			
14	The Energy Authority, Inc.	OS	4			
	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Duke Energy Progress, Inc.	LF	341			
2	Duke Energy Progress, Inc.	AD	341			
3	Duke Energy Progress, Inc.	OS	10			
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**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

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
1,457,762	44,683,301	34,863,413		79,546,714	2
					3
	-6,679,783	-176,002		-6,855,785	4
3,616,544	140,536,508	85,019,605		225,556,113	5
	-11,735,731	-371,094		-12,106,825	6
1,006,663	25,826,044	24,269,492		50,095,536	7
	-6,942,457	-122,780		-7,065,237	8
155,695	3,532,306	3,759,146		7,291,452	9
	-825,001	-20,174		-845,175	10
304,443	9,410,779	7,243,211		16,653,990	11
	-2,328,638	-38,869		-2,367,507	12
135,621	4,468,335	3,174,588		7,642,923	13
	-710,235	-15,975		-726,210	14
9,146,762	326,977,215	216,739,144	0	543,716,359	
2,100,206	-40,846,022	107,682,646	1,760,831	68,597,455	
11,246,968	**286,131,193**	**324,421,790**	**1,760,831**	**612,313,814**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

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.
333,355	7,677,265	7,708,838		15,386,103	1
	-1,394,343	-43,102		-1,437,445	2
					3
391,509	14,123,148	9,202,029		23,325,177	4
					5
	-2,244,592	-50,898		-2,295,490	6
5,529	1,050,068	404,412		1,454,480	7
					8
					9
419,608	17,340,822	9,863,270		27,204,092	10
					11
	-2,686,385	-50,829		-2,737,214	12
56,968	7,665,244	1,323,573		8,988,817	13
	-1,588,174	-6,969		-1,595,143	14
9,146,762	326,977,215	216,739,144	0	543,716,359	
2,100,206	-40,846,022	107,682,646	1,760,831	68,597,455	
11,246,968	**286,131,193**	**324,421,790**	**1,760,831**	**612,313,814**	

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
953,199	41,778,525	22,696,318		64,474,843	2
					3
	-6,005,639	-111,905		-6,117,544	4
74,998	1,690,475	1,820,270		3,510,745	5
	-341,385	-9,397		-350,782	6
13,501	376,319	321,438		697,757	7
	-82,269	-1,626		-83,895	8
116,391	3,448,855	2,826,822		6,275,677	9
	-630,983	-15,432		-646,415	10
52,495	1,998,432	1,266,721		3,265,153	11
	-259,810	-6,295		-266,105	12
10,868	466,770	258,004		724,774	13
	-82,116	-1,438		-83,554	14
9,146,762	326,977,215	216,739,144	0	543,716,359	
2,100,206	-40,846,022	107,682,646	1,760,831	68,597,455	
11,246,968	**286,131,193**	**324,421,790**	**1,760,831**	**612,313,814**	

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.
47,142	1,954,087	1,122,406		3,076,493	1
	-376,349	-5,682		-382,031	2
2,388			166,256	166,256	3
2,899			1,231	1,231	4
1,377			7,464	7,464	5
4,212			1,266,839	1,266,839	6
4,037			271,190	271,190	7
					8
154,762		20,475,003		20,475,003	9
	2,793,800			2,793,800	10
50		2,600		2,600	11
		19,200		19,200	12
24,365		1,502,354		1,502,354	13
		89		89	14
9,146,762	326,977,215	216,739,144	0	543,716,359	
2,100,206	-40,846,022	107,682,646	1,760,831	68,597,455	
11,246,968	**286,131,193**	**324,421,790**	**1,760,831**	**612,313,814**	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/Q4

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.
4,050		317,950		317,950	1
1,974		103,368		103,368	2
7,527	224,000	2,116,731		2,340,731	3
		-25,596		-25,596	4
1,025		49,525		49,525	5
604		55,545		55,545	6
			-146	-146	7
			-126	-126	8
			-270	-270	9
					10
			-533	-533	11
			-204	-204	12
			-1	-1	13
			-1	-1	14
9,146,762	326,977,215	216,739,144	0	543,716,359	
2,100,206	-40,846,022	107,682,646	1,760,831	68,597,455	
11,246,968	**286,131,193**	**324,421,790**	**1,760,831**	**612,313,814**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

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.
1,766			1,096	1,096	1
			-4	-4	2
			-406	-406	3
			60,437	60,437	4
					5
			-3,295	-3,295	6
			-4,637	-4,637	7
			-1,485	-1,485	8
			-2	-2	9
			-3	-3	10
			-555	-555	11
			-1,746	-1,746	12
			-30	-30	13
			-238	-238	14
9,146,762	326,977,215	216,739,144	0	543,716,359	
2,100,206	-40,846,022	107,682,646	1,760,831	68,597,455	
11,246,968	**286,131,193**	**324,421,790**	**1,760,831**	**612,313,814**	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/Q4

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.
1,882,999		83,433,061		83,433,061	1
309		261,481		261,481	2
333		15,390		15,390	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
9,146,762	326,977,215	216,739,144	0	543,716,359	
2,100,206	-40,846,022	107,682,646	1,760,831	68,597,455	
11,246,968	**286,131,193**	**324,421,790**	**1,760,831**	**612,313,814**	

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: 310.3 Line No.: 5 Column: j
Represents Generation imbalance pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.3 Line No.: 6 Column: j
Represents Generation imbalance pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.3 Line No.: 7 Column: j
Represents Generation imbalance 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.: 8 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.: 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.: 4 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.

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: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

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.: 2 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.: 3 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	14,106,955	14,817,549
5	(501) Fuel	716,702,684	864,621,618
6	(502) Steam Expenses	53,517,190	54,242,002
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.	65	-65
9	(505) Electric Expenses	7,450,715	7,400,350
10	(506) Miscellaneous Steam Power Expenses	18,743,585	18,183,387
11	(507) Rents		
12	(509) Allowances	17,169,996	13,640,526
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	827,691,060	972,905,497
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	13,598,207	13,394,902
16	(511) Maintenance of Structures	25,391,613	5,486,862
17	(512) Maintenance of Boiler Plant	40,874,905	43,658,585
18	(513) Maintenance of Electric Plant	18,618,073	29,813,044
19	(514) Maintenance of Miscellaneous Steam Plant	5,957,186	6,657,814
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	104,439,984	99,011,207
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	932,131,044	1,071,916,704
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	36,573,149	36,307,644
25	(518) Fuel	276,244,035	308,365,109
26	(519) Coolants and Water	9,046,891	8,884,540
27	(520) Steam Expenses	45,423,250	49,123,796
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	20,790,965	21,303,114
31	(524) Miscellaneous Nuclear Power Expenses	179,216,183	182,739,652
32	(525) Rents	618	
33	TOTAL Operation (Enter Total of lines 24 thru 32)	567,295,091	606,723,855
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	59,667,083	73,266,249
36	(529) Maintenance of Structures	13,388,034	12,537,039
37	(530) Maintenance of Reactor Plant Equipment	82,919,387	86,762,995
38	(531) Maintenance of Electric Plant	53,631,645	57,836,639
39	(532) Maintenance of Miscellaneous Nuclear Plant	55,488,912	45,930,851
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	265,095,061	276,333,773
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	832,390,152	883,057,628
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	8,646,000	7,652,327
45	(536) Water for Power		
46	(537) Hydraulic Expenses	-932,938	-830,335
47	(538) Electric Expenses	5,612,382	5,613,211
48	(539) Miscellaneous Hydraulic Power Generation Expenses	8,678,588	8,951,738
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	22,004,032	21,386,941
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	2,733,907	2,614,689
54	(542) Maintenance of Structures	743,175	1,270,898
55	(543) Maintenance of Reservoirs, Dams, and Waterways	3,173,870	3,553,530
56	(544) Maintenance of Electric Plant	6,051,617	6,721,117
57	(545) Maintenance of Miscellaneous Hydraulic Plant	4,021,019	3,941,237
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	16,723,588	18,101,471
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	38,727,620	39,488,412

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	8,734,129	5,341,868
63	(547) Fuel	507,677,739	299,835,877
64	(548) Generation Expenses	2,176,467	1,653,542
65	(549) Miscellaneous Other Power Generation Expenses	9,922,370	10,651,187
66	(550) Rents	-61,682	-33,910
67	TOTAL Operation (Enter Total of lines 62 thru 66)	528,449,023	317,448,564
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	5,050,700	3,451,402
70	(552) Maintenance of Structures	6,882,389	7,142,474
71	(553) Maintenance of Generating and Electric Plant	6,775,578	7,437,884
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	4,472,389	5,419,576
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	23,181,056	23,451,336
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	551,630,079	340,899,900
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	501,354,859	348,770,283
77	(556) System Control and Load Dispatching	32,042	7,922
78	(557) Other Expenses	-17,901,355	198,416,760
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	483,485,546	547,194,965
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,838,364,441	2,882,557,609
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	12,057	10,256
84			
85	(561.1) Load Dispatch-Reliability	1,569,257	1,245,799
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	8,618,014	8,471,596
87	(561.3) Load Dispatch-Transmission Service and Scheduling	812,692	811,724
88	(561.4) Scheduling, System Control and Dispatch Services	832	1,614
89	(561.5) Reliability, Planning and Standards Development	305,750	231,610
90	(561.6) Transmission Service Studies	9,768	22,370
91	(561.7) Generation Interconnection Studies	-1,511	-37,269
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,647,297	1,692,699
94	(563) Overhead Lines Expenses	938,130	1,068,110
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	3,035,624	2,637,455
97	(566) Miscellaneous Transmission Expenses	11,314,151	10,875,479
98	(567) Rents	147,140	68,458
99	TOTAL Operation (Enter Total of lines 83 thru 98)	28,409,201	27,099,901
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	943,999	152,022
103	(569.1) Maintenance of Computer Hardware	77,034	221,392
104	(569.2) Maintenance of Computer Software	2,667,421	2,129,308
105	(569.3) Maintenance of Communication Equipment	210	23,389
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	8,453,316	7,865,412
108	(571) Maintenance of Overhead Lines	25,081,168	15,857,393
109	(572) Maintenance of Underground Lines	-1,248	10,622
110	(573) Maintenance of Miscellaneous Transmission Plant	1,451,315	14,870
111	TOTAL Maintenance (Total of lines 101 thru 110)	38,673,215	26,274,408
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	67,082,416	53,374,309

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	1,207,429	667,947
135	(581) Load Dispatching	8,425,724	7,315,735
136	(582) Station Expenses	1,282,105	1,711,226
137	(583) Overhead Line Expenses	2,980,905	3,269,939
138	(584) Underground Line Expenses	11,475,994	11,119,860
139	(585) Street Lighting and Signal System Expenses	492,035	1,168,723
140	(586) Meter Expenses	10,709,054	16,022,534
141	(587) Customer Installations Expenses	10,526,414	7,449,234
142	(588) Miscellaneous Expenses	45,615,305	45,397,509
143	(589) Rents	117,896	252,043
144	TOTAL Operation (Enter Total of lines 134 thru 143)	92,832,861	94,374,750
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	977,779	272,276
147	(591) Maintenance of Structures	2,056	
148	(592) Maintenance of Station Equipment	4,569,308	3,701,202
149	(593) Maintenance of Overhead Lines	195,064,035	152,481,665
150	(594) Maintenance of Underground Lines	20,327,339	8,920,262
151	(595) Maintenance of Line Transformers	2,816,316	1,866,435
152	(596) Maintenance of Street Lighting and Signal Systems	12,799,453	5,111,083
153	(597) Maintenance of Meters	2,314,975	2,549,231
154	(598) Maintenance of Miscellaneous Distribution Plant	3,921,976	6,912,040
155	TOTAL Maintenance (Total of lines 146 thru 154)	242,793,237	181,814,194
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	335,626,098	276,188,944
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	92,741	396,348
160	(902) Meter Reading Expenses	2,455,088	3,650,664
161	(903) Customer Records and Collection Expenses	67,078,376	68,063,002
162	(904) Uncollectible Accounts	16,637,687	11,758,924
163	(905) Miscellaneous Customer Accounts Expenses	264,709	367,337
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	86,528,601	84,236,275

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	4,205	320
169	(909) Informational and Instructional Expenses	149,499	105,180
170	(910) Miscellaneous Customer Service and Informational Expenses	19,151,412	20,614,998
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	19,305,116	20,720,498
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	4,784	267
175	(912) Demonstrating and Selling Expenses	13,610,071	10,789,667
176	(913) Advertising Expenses	565,426	793,089
177	(916) Miscellaneous Sales Expenses	58,889	
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	14,239,170	11,583,023
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	241,315,539	123,190,385
182	(921) Office Supplies and Expenses	86,395,771	80,674,709
183	(Less) (922) Administrative Expenses Transferred-Credit	39,763,864	40,066,555
184	(923) Outside Services Employed	71,238,493	75,094,166
185	(924) Property Insurance	2,399,590	10,862,755
186	(925) Injuries and Damages	21,835,563	27,990,183
187	(926) Employee Pensions and Benefits	102,239,981	130,547,563
188	(927) Franchise Requirements	47	
189	(928) Regulatory Commission Expenses	12,121,234	11,375,477
190	(929) (Less) Duplicate Charges-Cr.	34,592,827	31,140,037
191	(930.1) General Advertising Expenses	5,346,453	5,439,844
192	(930.2) Miscellaneous General Expenses	-26,059,961	-29,328,249
193	(931) Rents	45,607,149	47,215,358
194	TOTAL Operation (Enter Total of lines 181 thru 193)	488,083,168	411,855,599
195	Maintenance		
196	(935) Maintenance of General Plant	2,861,306	2,287,672
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	490,944,474	414,143,271
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,852,090,316	3,742,803,929

Schedule Page: 320 Line No.: 5 Column: b

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.: 5 Column: c

Total fuel costs include accounts 0501007, 0501008, 0501009 for Coal Ash Beneficial Reuse in the amount of $91,942,445.

Schedule Page: 320 Line No.: 13 Column: b

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.: 13 Column: c

This includes $13,635,107 for renewable energy credits consumption expense represented in account 0509213. It also includes $5,450 of Emission Allowances in account 0509000 as reported on page 228a.

Schedule Page: 320 Line No.: 63 Column: b

Total fuel costs include Biogas accounts 0547106 and 0547107 in the amount of $1,665,650.

Schedule Page: 320 Line No.: 63 Column: c

Total fuel costs include Biogas accounts 0547106 and 0547107 in the amount of $591,816.

Also includes $11,387,785 that represents the amounts Duke Energy Carolinas owes Piedmont Natural Gas, which was acquired by Duke Energy on 10/3/2016, an affiliate of Duke Energy Carolinas.

Schedule Page: 320 Line No.: 196 Column: b

Total Maintenance of General Plant include accounts 0932000, 0935100 and 0935200 for Maintenance of General Plant.

Schedule Page: 320 Line No.: 197 Column: c

Applicable to formula rates approved in FERC proceedings listed on page 106: Administrative general expenses allocable to production exclude EPRI dues.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	ABT INC	LU	(1)			
3	ACTIVE CONCEPTS LLC	LU	(1)			
4	AKS REAL ESTATE HOLDINGS LLC	LU	(1)			
5	ALAMANCE HYDRO, LLC	LU	(1)			
6	ALL-STATES MEDICAL SUPPLY INC.	LU	(1)			
7	AMETHYST SOLAR , LLC	LU	(1)			
8	ANGEL SOLAR , LLC	LU	(1)			
9	APPLE DATA CENTER PV2	IU	(1)			
10	APPLE FUEL CELL FACILITY	LU	(1)			
11						
12	APPLE INC CLAREMONT PV3	LU	(1)			
13	APPLE ONE, LLC	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	AUDREY SOLAR , LLC	LU	(1)			
8	AUTEN ROAD FARM,LLC	LU	(1)			
9	AVALON HYDROPOWER, LLC	LU	(1)			
10	AYRSHIRE HOLDINGS LLC	LU	(1)			
11	AYRSHIRE HOLDINGS LLC	AD	(1)			
12	BAKATSIAS SOLAR FARM, LLC	LU	(1)			
13	BANK OF AMERICA	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	Barbara Ann Evans	IU	(1)			
2	BARRY R WHARTON	LU	(1)			
3	BATTLEGROUND SOLAR I, LLC	LU	(1)			
4	BEETLE SOLAR, LLC	LU	(1)			
5	BELWOOD FARM, LLC	LU	(1)			
6	BENJAMIN R. EUSTICE	LU	(1)			
7	BERNHARDT FURNITURE COMPANY	LU	(1)			
8	BETH SOLAR LLC	LU	(1)			
9	BG STEWART SOLAR FARM, LLC	LU	(1)			
10	BIG BOY SOLAR,LLC	LU	(1)			
11	BIOMERIEUX, INC	LU	(1)			
12	BLUE BRIGHT VENTURES, LLC	LU	(1)			
13	BLUM, INC.	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	BOYD LEON HYDER	LU	(1)			
2	BRANCH,JAMES DAVID DR	LU	(1)			
3	BRIAN M ATTIS	LU	(1)			
4	BRYAN C TURNER	LU	(1)			
5	BUDDY SOLAR, LLC	LU	(1)			
6	BURLINGTON HYDRO LLC	LU	(1)			
7	C2 Solar	IU	(1)			
8	CAROL JEAN SOLAR,LLC	LU	(1)			
9	CARRBORO COMMUNITY SOLAR LLC	LU	(1)			
10	Catawba County - Blackburn Landfill	LU	(1)			
11	CATAWBA GREEN STEP SOLAR, LLC	LU	(1)			
12	CATAWBA SOLAR, LLC	LU	(1)			
13	CHAPEL HILL TIRE CO	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	CHAPEL HILL TIRE COMPANY, INC.	LU	(1)			
2	CHARLIE SOLAR, LLC	LU	(1)			
3	CHARLOTTE SOLAR, LLC	LU	(1)			
4	CHEROKEE FALLS HYDRO	LU	(1)			
5	CISCO SYSTEMS INC	IU	(1)			
6	CITY OF CHARLOTTE	IU	(1)			
7	CITY VIEW COMMERCIAL LLC	LU	(1)			
8	CLEAN ENERGY,LLC	LU	(1)			
9	Cliffside Mills LLC	LU	(1)			
10	CLINE SOLAR, LLC	LU	(1)			
11	CLOVER SCHOOL DISTRICT 2	LU	(1)			
12	COC SURRY LFG,LLC	LU	(1)			
13	COMMONWEALTH BRANDS INC	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	CONCORD ENERGY LLC	LU	(1)			
2	CONGOLINA SOLAR, LLC	LU	(1)			
3	Converse Energy - Clifton Dam #3 Hydro	LU	(1)			
4	COUNTY HOME SOLAR CENTER LLC	LU	(1)			
5	CT WILSON PROPERTIES, LLC	LU	(1)			
6	DANIEL FARM, LLC	LU	(1)			
7	DANIELLE SEAMAN	LU	(1)			
8	DAVID BOYER	LU	(1)			
9	DAVID H NEWMAN	LU	(1)			
10	DAVIDSON GAS PRODUCERS, LLC	LU	(1)			
11	DDM MORTGAGE CORPORATION	LU	(1)			
12	DECISION SUPPORT	LU	(1)			
13	DEE INDUSTRIES	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	DELTA PRODUCTS CORP.	LU	(1)			
2	DIANE E JAMES	LU	(1)			
3	DIBRELL FARM, LLC	LU	(1)			
4	DIRK J SPRUYT	LU	(1)			
5	DIXON DAIRY ROAD, LLC	LU	(1)			
6	DOMENICO SANTILLI	LU	(1)			
7	DON A BICKNELL	LU	(1)			
8	DRAGSTRIP FARM	LU	(1)			
9	DURHAM LANDFILL ELECTRICITY LLC	LU	(1)			
10	DURHAM SOLAR , LLC	LU	(1)			
11	EARNHARDT-CHILDRESS RACING	LU	(1)			
12	TECHNOLOGIES,LLC					
13	ELLIANA SOLAR, LLC	LU	(1)			
14	ELSEWHERE LIVING MUSEUM	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	ESTES EXPRESS LINES, INC	LU	(1)			
2	FACILE SOLAR, LLC	LU	(1)			
3	FISHER SOLAR FARM, LLC	LU	(1)			
4	FLASH SOLAR , LLC	LU	(1)			
5	FLS OWNER II, LLC	LU	(1)			
6	FOOTHILLS WINEWORX INC	LU	(1)			
7	FREEMONT SOLAR CENTER, LLC	LU	(1)			
8	FREIRICH FOODS, LLC	LU	(1)			
9	FRESH AIR ENERGY XV, LLC	LU	(1)			
10	FRESH AIR ENERGY XXIX, LLC	LU	(1)			
11	GAIL SEVERS SCHNEITLER	LU	(1)			
12	GAS RECOVERY SYSTEMS, LLC	LU	(1)			
13	GASTON COUNTY	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	GENERAL ELECTRIC COMPANY	LU	(1)			
2	GERALD W. MEISNER	LU	(1)			
3	GERMANTOWN SOLAR, LLC	LU	(1)			
4	GOOD SOLAR ELECTRIC, LLC	IU	(1)			
5	GREENSBORO PLUMBING SUPPLY CO	LU	(1)			
6	GREENVILLE COUNTY SCHOOLS	LU	(1)			
7	GREENVILLE GAS PRODUCERS, LLC	LU	(1)			
8	GWENYTH T REID	LU	(1)			
9	Haneline Power, LLC	LU	(1)			
10	HAROLD FERGUSON	LU	(1)			
11	Haw River Hydro Co - Saxapahaw Hydro	LU	(1)			
12	HAYNES FARM, LLC	LU	(1)			
13	HMS Holdings Limited Partnership	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	HOFFMAN & HOFFMAN	LU	(1)			
2	HOWELL MIDLAND FARM, LLC	LU	(1)			
3	HUSKY SOLAR LLC	LU	(1)			
4	HUTCHINSON FARM,LLC	LU	(1)			
5	INDUSTRIAL CENTERS, LLC	LU	(1)			
6	INNOVATIVE SOLAR 14, LLC	LU	(1)			
7	INNOVATIVE SOLAR 15, LLC	LU	(1)			
8	INNOVATIVE SOLAR 16, LLC	LU	(1)			
9	INNOVATIVE SOLAR 18, LLC	LU	(1)			
10	INNOVATIVE SOLAR 23, LLC	LU	(1)			
11	INNOVATIVE SOLAR 26, LLC	LU	(1)			
12	IRVINE RIVER COMPANY	LU	(1)			
13	ITRON INC	LU	(1)			
14						
	Total					

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	JACOB SOLAR LLC	LU	(1)			
2	Jafasa Farms Greenhouse	LU	(1)			
3	Jafasa Farms Residence	LU	(1)			
4	JAMES J BOYLE	LU	(1)			
5	JARROD W BARTRON	LU	(1)			
6	JEFFERY LYNN PARDUE	LU	(1)			
7	JIM AND LINDA ALEXANDER	LU	(1)			
8	JOHN B ROBBINS	LU	(1)			
9	JOHN H. DILIBERTI	LU	(1)			
10	JUBA ALUMINUM PRODUCTS COMPANY	LU	(1)			
11	JUDITH LOBERG	LU	(1)			
12	KMBA, LLC	LU	(1)			
13	LAFAYETTE SOLAR I, LLC	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	LAMAR BAILES	LU	(1)			
2	LARRY STENGER	LU	(1)			
3	LAURA J BALLANCE	LU	(1)			
4	LAWRENCE ELECTRIC	LU	(1)			
5	LEON'S BEAUTY SCHOOL, INC	LU	(1)			
6	LINCOLN SOLAR LLC	LU	(1)			
7	LOCKHART - LOWER PACOLET HYDRO	LU	(1)			
8	LOCKHART - UPPER PACOLET HYDRO	LU	(1)			
9	LOCKHART BIOENERGY, LLC	LU	(1)			
10	LOCKHART Minimum Flow	LU	(1)			
11	LOCKHART POWER COMPANY	LU	(1)			
12	LOTUS SOLAR LLC	LU	(1)			
13	LUX SOLAR I LLC	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	LYNWOOD SOLAR I LLC	LU	(1)			
2						
3	MARIPOSA SOLAR CENTER LLC	LU	(1)			
4	MARK S TRUSTIN	LU	(1)			
5	MARKET FARM, LLC	LU	(1)			
6	MARSHVILLE FARM ,LLC	LU	(1)			
7	MARTIN TRUEX JR. LLC	LU	(1)			
8	MATTHEW C ROBERTS	LU	(1)			
9	MAYBERRY SOLAR LLC	LU	(1)			
10	Mayo Hydropower LLC - Mayo Hydro	LU	(1)			
11	MCBRIDE PLACE ENERGY, LLC	LU	(1)			
12	MEADOWBROOK SOLAR, LLC	LU	(1)			
13	MIDTOWN SHOPS, LLC	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	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						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	Net metering for SC DERP	LU	(1)			
2	NEISLER STREET SOLAR I LLC	LU	(1)			
3	NEWTON-CONOVER CITY SCHOOLS	LU	(1)			
4	NICK SOLAR,LLC	LU	(1)			
5	Northbrook Carolina - Boyds Mill Hydro	IU	(1)			
6	Northbrook Carolina - Holliday's	IU	(1)			
7	Bridge Hydro					
8	Northbrook Carolina - Saluda Hydro	IU	(1)			
9	Northbrook Carolina-Turner ShoalsHydro	LU	(1)			
10	NYPRO,INC	LU	(1)			
11	OAKDALE HOLDING LLC	LU	(1)			
12	OENOPHILIA	LU	(1)			
13	OLD CAROLEEN SOLAR FARM, LLC	LU	(1)			
14	OLD DOMINION FREIGHT LINE INC	LU	(1)			
	Total					

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)	Average Monthly CP Demand (f)
1	OLD PAGELAND-MONROE ROAD	LU	(1)			
2	SOLAR FARM LLC					
3	ORBIT ENERGY CHARLOTTE,LLC	LU	(1)			
4	ORBIT ENERGY CHARLOTTE,LLC	AD	(1)			
5						
6	OWEN SOLAR , LLC	LU	(1)			
7	PAUL M NEUBAUER	LU	(1)			
8	Pelzer Hydro Co - Lower Pelzer Hydro	LU	(1)			
9	Pelzer Hydro Co - Upper Pelzer Hydro	LU	(1)			
10	PHILIP E MINER	LU	(1)			
11	Pickins Mill Hydro LLC	IU	(1)			
12	PIEDMONT COMPANY, INC	LU	(1)			
13	PIEDMONT COMPANY, INC	AD	(1)			
14	PIERRE BURKE	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	PUBLIC LIBRARY OF CHARLOTTE	LU	(1)			
2	R B SOLAR LLC	LU	(1)			
3	R LAWRENCE ASHE JR	LU	(1)			
4	RAJAH Y CHACKO	LU	(1)			
5	RAJENDRA MOREY	LU	(1)			
6	RAMONA L SHERWOOD	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						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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						
2	ROPER FARM, LLC	LU	(1)			
3	ROUSCH & YATES RACING ENGINES, LLC	LU	(1)			
4	RUNAWAY PROPERTIES LLC	LU	(1)			
5	RUSSELL VON STEIN	LU	(1)			
6	RUTHERFORD FARM, LLC	LU	(1)			
7	SAIA MOTOR FREIGHT LINE, LLC	LU	(1)			
8	SALEM ENERGY SYSTEMS, LLC	LU	(1)			
9	SALISBURY SOLAR, LLC	LU	(1)			
10	SANDAN FARM	LU	(1)			
11	SHELBY RANDOLPH ROAD SOLAR I , LLC	LU	(1)			
12	SHOE SHOW, INC	LU	(1)			
13	SID SOLAR I, LLC	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	SIGMON CATAWBA FARM,LLC	LU	(1)			
2	SONNE TWO,LLC	LU	(1)			
3	SOPHIE SOLAR, LLC	LU	(1)			
4	SOUTH WINSTON FARM, LLC	LU	(1)			
5	South Yadkin Power, Inc.	LU	(1)			
6	SOUTHDATA INC	LU	(1)			
7	SPARTANBURG WATER SYSTEM	LU	(1)			
8	SPENCER FARM, LLC	LU	(1)			
9	SPENCER MOUNTAIN HYDROPOWER, LLC	LU	(1)			
10	STANLEY CHAMBERLAIN	LU	(1)			
11	Star Solar, LLC	LU	(1)			
12	STATESVILLE SOLAR, LLC	LU	(1)			
13	Steve Mason Ent., Inc. - Long Shoals	LU	(1)			
14	Hydro					
	Total					

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	STIKELEATHER FARM, LLC	LU	(1)			
2	STONEVILLE SOLAR LLC	LU	(1)			
3	STOUT FARM LLC	LU	(1)			
4	SUN CAPITAL,INC	LU	(1)			
5	SUN EDISON LLC	LU	(1)			
6	SUN LIGHT 1 LLC	LU	(1)			
7	SUSAN E REYNOLDS	LU	(1)			
8	T.S. DESIGNS, INC.	LU	(1)			
9	TEMPLE EMANUEL	LU	(1)			
10	TENCARVA MACHINERY COMPANY	LU	(1)			
11	TerraForm LLC; DBA: SunE B9 Holdings,	LU	(1)			
12	LLC					
13	THE CITY OF CHARLOTTE	LU	(1)			
14	THE MEASURED DOSE PHARMACY 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 Classifi-cation (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	THE NORTHWESTERN MUTUAL LIFE	LU	(1)			
2	INSURANCE					
3	THE ROCKET SHOP, LLC	LU	(1)			
4	THE ROPER GROUP, LLC	IU	(1)			
5	THOMAS SCHOPLER	LU	(1)			
6	TIBURON HOLDINGS LLC	LU	(1)			
7	TONY M SMITH	LU	(1)			
8	Town Of Lake Lure - Lake Lure Hydro	LU	(1)			
9	TRINITY POWER NC, LLC	LU	(1)			
10	TRIPPLE STATE FARM, LLC	LU	(1)			
11	TROPICAL NUT & FRUIT CO	LU	(1)			
12	TWC ADMINISTRATION LLC	LU	(1)			
13	TWO LINES FARM, LLC	LU	(1)			
14	UNC - CHAPEL HILL	LU	(1)			
	Total					

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	UNIFI MANUFACTURING, INC	LU	(1)			
2	UNITED SEWING MACHINE SALES, LLC	LU	(1)			
3	UNITED THERAPEUTICS CORPORATION	LU	(1)			
4	VETRORESINA LLC	LU	(1)			
5	VIDYA SAGAR SETHI	LU	(1)			
6	VOLT SOLAR, LLC	LU	(1)			
7	W B MOORE CO OF CHAR	LU	(1)			
8	WACO FARM, LLC	LU	(1)			
9	WALLACE & GRAHAM PA	LU	(1)			
10	WALTER C. MCGERVEY	LU	(1)			
11	WALTER O BRADLEY	LU	(1)			
12	WATAUGA COUNTY	LU	(1)			
13	WEST SALISBURY FARM, LLC	LU	(1)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	WHITE CROSS FARM, LLC	LU	(1)			
2	WHITE CROSS SOLAR LLC	LU	(1)			
3	WILKES COUNTY	LU	(1)			
4	WILLIAM D MOORE	LU	(1)			
5	WILLIAM P MILLER	LU	(1)			
6	WM RENEWABLE ENERGY,LLC	LU	(1)			
7	WRIGHT OF THOMASVILLE INC	LU	(1)			
8	YADKIN 601 FARM,LLC	LU	(1)			
9	YADKINVILLE SOLAR, LLC	LU	(1)			
10	YORK ROAD SOLAR I , LLC	LU	(1)			
11	YUZE HOLDINGS LLC	IU	(1)			
12	YVES NAAR	LU	(1)			
13	Southeastern Power Administration	OS	124			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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						
2	Small Customer Generator Credits	OS				
3	North Carolina Municipal Power Agency	EX	271			
4	North Carolina Electric Member	EX	273			
5	Corporation					
6	Piedmont Municipal Power Agency	EX	314			
7	North Carolina Municipal Power Agency	OS	271			
8	North Carolina Electric Member	OS	273			
9	Corporation					
10	Piedmont Municipal Power Agency	OS	313			
11	Blue Ridge Electric Membership	RQ	315			
12	Corporation					
13	Blue Ridge Electric Membership Corporn	AD	315			
14	Corporation					
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	Cherokee County Cogeneration Partners	OS	(2)			
2	LLC					
3	Cherokee County Cogeneration Partners	AD	(2)			
4	LLC					
5	City of Concord, North Carolina	RQ	327			
6	City of Concord, North Carolina	AD	327			
7	City of Kings Mountain, North Carolina	RQ	331			
8	Duke Energy Progress	OS	341			
9	Duke Energy Progress	AD	341			
10	EDF Trading North America, LLC	OS	(2)			
11	Exelon Generation Company, LLC	OS	(2)			
12	Haywood Electric Membership	RQ	335			
13	Corporation					
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	Haywood Electric Membership	AD	335			
2	Corporation					
3	Haywood Electric Membership	RQ	335			
4	Corporation					
5	Macquarie Energy, LLC	OS	(2)			
6	Morgan Stanley Capital Group Inc.	OS	(2)			
7	NC Electric Member Corporation	OS	(2)			
8	NC Electric Member Corporation	RQ	326			
9	North Carolina Municipal Power Agency	OS	(2)			
10	Number 1					
11	North Carolina Municipal Power Agency	OS	318			
12	Number 1					
13	NTE Carolinas LLC	OS	(2)			
14						
	Total					

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	Piedmont Electric Membership	RQ	316			
2	Corporation					
3	Piedmont Electric Membership	AD	316			
4	Corporation					
5	Piedmont Municipal Power Agency	RQ	340			
6	PJM Settlements, Inc	OS	(2)			
7	PJM Settlements, Inc	AD	(2)			
8	Rainbow Energy marketing Corporation	OS	(2)			
9	South Carolina Electric & Gas Company	OS	(2)			
10	South Carolina Electric & Gas Company	OS	(2)			
11	Transmission					
12	South Carolina Electric & Gas Company	AD	(2)			
13	Transmission					
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	Southern Company Services, Inc.	OS	(2)			
2	Southern Company Services, Inc.	AD	(2)			
3	Tennessee Valley Authority	OS	(2)			
4	The Energy Authority	OS	(2)			
5	Town of Dallas, North Carolina	RQ	328			
6	Town of Forest City, North Carolina	RQ	330			
7	Broad River Energy Center c/o Calpine	EX	(3)			
8	Corp					
9	Macquarie Energy LLC	EX	(3)			
10	NCMPA	EX	(3)			
11	NTE	EX	(3)			
12	Piedmont Municipal Power Agency	EX	(3)			
13						
14						
	Total					

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	Southern Power Company - Cleveland	EX	(3)			
2	Plant					
3	Southern Power Company - Rowan Plant	EX	(3)			
4	City of Seneca	EX	(4)			
5	EnergyUnited Electric Memb					
6	NC Electric Membership	EX	(4)			
7	Corporation					
8	NCMPA	EX	(4)			
9	Piedmont Municipal Power Agency	EX	(4)			
10	SCE&G COMPANY	EX	(4)			
11	South Carolina Public Service	EX	(4)			
12	Authority p2p					
13	Brookfield Energy Marketing LP	OS	Ferc 890			
14						
	Total					

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	Eagle Energy Partners	OS	Ferc 890			
2	Endure Energy LLC	OS	Ferc 890			
3	Exelon Power Team	OS	Ferc 890			
4	Florida Power & Light EMT	OS	Ferc 890			
5	NTE	OS	Ferc 890			
6	Lockhart Power Company	OS	Ferc 890			
7	Macquarie Energy LLC	OS	Ferc 890			
8	Mercuria Energy American	OS	Ferc 890			
9	Morgan Stanley Capital Grp INC	OS	Ferc 890			
10	Rainbow Energy Marketing	OS	Ferc 890			
11	SC Public Service Authority	OS	Ferc 890			
12	SCANA Energy Marketing	OS	Ferc 890			
13	Southern Wholesale	OS	Ferc 890			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	Tenaska Power Services Co.	OS	Ferc 890			
2	Tennessee Valley Authority	OS	Ferc 890			
3	The Energy Authority	OS	Ferc 890			
4	Westar Energy	OS	Ferc 890			
5	Operating Regulating	EX	(5)			
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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)	
4,032				271,392		271,392	1
71				4,869		4,869	2
99				3,269		3,269	3
3				106		106	4
272				16,844		16,844	5
19				602		602	6
5,972				399,097		399,097	7
9,214				621,095		621,095	8
37,452				2,215,514		2,215,514	9
69,835				4,002,191		4,002,191	10
							11
35,544				2,122,309		2,122,309	12
9,443				634,438		634,438	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
38,608				2,806,616		2,806,616	1
5,916				263,628		263,628	2
15,913				688,885		688,885	3
5,679				435,999		435,999	4
8,765				677,270		677,270	5
6,971				466,381		466,381	6
4,968				332,807		332,807	7
8,919				603,196		603,196	8
4,470				310,879		310,879	9
36,227				1,874,087		1,874,087	10
7,358				369,458		369,458	11
6,734				437,381		437,381	12
10				667		667	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
134				7,897		7,897	1
3				98		98	2
5,656				372,131		372,131	3
6,854				459,905		459,905	4
7,227				554,422		554,422	5
2				59		59	6
658				37,591		37,591	7
8,264				550,160		550,160	8
9,149				643,332		643,332	9
4,441				297,065		297,065	10
142				4,717		4,717	11
124				8,284		8,284	12
661				38,783		38,783	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
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)	
12				391		391	1
11				372		372	2
1				34		34	3
7				187		187	4
5,825				395,559		395,559	5
489				35,072		35,072	6
25				1,451		1,451	7
6,667				434,052		434,052	8
1				37		37	9
15,770				521,497		521,497	10
923				59,610		59,610	11
3,125				206,935		206,935	12
20				673		673	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
7				202		202	1
6,898				402,653		402,653	2
9,065				605,261		605,261	3
3,596				206,090		206,090	4
109				3,621		3,621	5
7,472				330,235		330,235	6
				8		8	7
11,668				376,935		376,935	8
1,312				42,867		42,867	9
8,381				566,565		566,565	10
34				1,926		1,926	11
6,623				464,942		464,942	12
205				6,849		6,849	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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 ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
59,792				4,101,299		4,101,299	1
1,092				71,192		71,192	2
4,467				256,838		256,838	3
3,667				246,131		246,131	4
46				2,952		2,952	5
8,734				587,089		587,089	6
6				340		340	7
1				31		31	8
2				61		61	9
13,016				906,025		906,025	10
101				3,996		3,996	11
37				1,208		1,208	12
7				219		219	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
30				1,003		1,003	1
5				327		327	2
8,597				661,375		661,375	3
5				146		146	4
6,934				534,306		534,306	5
2				67		67	6
4				111		111	7
9,020				602,324		602,324	8
15,058				873,254		873,254	9
5,974				399,778		399,778	10
85				2,994		2,994	11
							12
8,874				636,628		636,628	13
6				187		187	14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
728				47,219		47,219	1
3,444				229,998		229,998	2
8,910				593,698		593,698	3
8,456				563,789		563,789	4
5				161		161	5
36				1,201		1,201	6
9,090				611,282		611,282	7
93				2,872		2,872	8
5,779				389,224		389,224	9
5,211				350,178		350,178	10
1				28		28	11
25,770				1,710,388		1,710,388	12
28,993				1,812,000		1,812,000	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
1,480				99,343		99,343	1
6				180		180	2
2,737				194,239		194,239	3
7				377		377	4
72				2,409		2,409	5
34				1,894		1,894	6
13,556				655,044		655,044	7
1				46		46	8
411				28,973		28,973	9
6				189		189	10
5,988				429,299		429,299	11
8,107				626,047		626,047	12
84				2,984		2,984	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
144				4,805		4,805	1
9,010				600,508		600,508	2
8,411				567,609		567,609	3
9,473				641,470		641,470	4
96				6,193		6,193	5
3,469				267,811		267,811	6
3,293				256,478		256,478	7
3,389				225,555		225,555	8
3,791				252,969		252,969	9
3,772				253,393		253,393	10
3,610				239,865		239,865	11
3,735				272,636		272,636	12
77				3,939		3,939	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	(Mo, Da, Yr) 05/29/2019	End of 2018/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.
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)	
8,906				629,666		629,666	1
4				136		136	2
8				274		274	3
5				155		155	4
7				312		312	5
5				153		153	6
2				60		60	7
3				84		84	8
9				299		299	9
12				400		400	10
143				5,859		5,859	11
13				417		417	12
3,377				229,253		229,253	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
6				294		294	1
23				788		788	2
7				214		214	3
2				78		78	4
42				1,354		1,354	5
9,527				616,095		616,095	6
4,432				309,777		309,777	7
4,835				337,938		337,938	8
19,751				1,066,592		1,066,592	9
5,077				354,891		354,891	10
10,067				646,327		646,327	11
7,173				479,280		479,280	12
3,992				269,504		269,504	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
171				5,681		5,681	1
							2
9,362				624,561		624,561	3
3				82		82	4
8,446				569,985		569,985	5
7,895				600,242		600,242	6
73				2,452		2,452	7
6				186		186	8
1,452				110,961		110,961	9
3,831				272,626		272,626	10
18,990				1,022,773		1,022,773	11
9,248				620,372		620,372	12
70				4,797		4,797	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
3,632				258,766		258,766	1
1,252				84,119		84,119	2
9,506				634,318		634,318	3
5,389				359,947		359,947	4
10				547		547	5
5,112				335,095		335,095	6
8,606				573,039		573,039	7
8,808				682,616		682,616	8
8,852				592,348		592,348	9
8,386				562,598		562,598	10
8,174				634,464		634,464	11
875				28,386		28,386	12
16				1,028		1,028	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
1,008				43,553		43,553	1
3,636				246,581		246,581	2
180				6,015		6,015	3
8,498				655,170		655,170	4
3,779				192,080		192,080	5
12,412				620,538		620,538	6
							7
10,206				535,293		535,293	8
19,791				967,865		967,865	9
228				7,546		7,546	10
25				815		815	11
23				752		752	12
1,271				86,171		86,171	13
1,986				66,256		66,256	14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
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)	
9,466				661,933		661,933	1
							2
126				6,279		6,279	3
				6,874		6,874	4
							5
9,304				620,481		620,481	6
3				109		109	7
10,976				475,243		475,243	8
7,427				318,523		318,523	9
6				199		199	10
994				32,362		32,362	11
134				5,544		5,544	12
5				201		201	13
11				377		377	14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
42				1,279		1,279	1
6,599				426,904		426,904	2
5				170		170	3
3				86		86	4
5				141		141	5
3				85		85	6
532				35,954		35,954	7
4				130		130	8
4,011				269,086		269,086	9
2,822				121,739		121,739	10
3				84		84	11
5,813				388,507		388,507	12
714				26,970		26,970	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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
9,569				643,019		643,019	2
184				6,540		6,540	3
8				276		276	4
2				53		53	5
137,955				8,590,139		8,590,139	6
312				21,381		21,381	7
29,357				1,605,081		1,605,081	8
2,115				140,349		140,349	9
29				965		965	10
3,503				237,912		237,912	11
4,813				159,629		159,629	12
8,516				579,241		579,241	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
8,188				558,710		558,710	1
9,842				661,887		661,887	2
7,790				523,573		523,573	3
9,043				647,633		647,633	4
1,103				79,367		79,367	5
9				300		300	6
2,193				120,083		120,083	7
9,009				612,033		612,033	8
1,489				90,880		90,880	9
9				282		282	10
9,472				630,414		630,414	11
8,557				618,024		618,024	12
2,032				68,210		68,210	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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.
9,115				608,557		608,557	1
13				414		414	2
8,674				571,774		571,774	3
25				815		815	4
10,531				714,021		714,021	5
174				5,760		5,760	6
4				128		128	7
10				322		322	8
6				192		192	9
242				7,916		7,916	10
15,406				1,044,521		1,044,521	11
							12
412				27,871		27,871	13
6				203		203	14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
5				161		161	1
							2
2				69		69	3
28				1,342		1,342	4
7				223		223	5
9,259				620,429		620,429	6
5				149		149	7
10,464				638,030		638,030	8
1				37		37	9
9,562				621,246		621,246	10
27				898		898	11
1,294				85,452		85,452	12
8,579				666,406		666,406	13
4,515				162,987		162,987	14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
1,409				95,450		95,450	1
294				18,230		18,230	2
4,705				298,714		298,714	3
406				31,840		31,840	4
5				171		171	5
1,027				66,237		66,237	6
32				1,039		1,039	7
8,804				685,202		685,202	8
198				6,559		6,559	9
1				42		42	10
6				200		200	11
28				889		889	12
8,627				594,867		594,867	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
8,231				629,711		629,711	1
3,700				249,428		249,428	2
92				2,970		2,970	3
6				198		198	4
3				94		94	5
13,772				902,888		902,888	6
90				3,005		3,005	7
5,371				360,795		360,795	8
6,372				425,693		425,693	9
3,589				240,726		240,726	10
33				1,854		1,854	11
2				49		49	12
				95,017		95,017	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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
				13,320		13,320	2
	3,526,980	3,614,982	-733,805	795,191		61,386	3
47,671	2,892,499	3,020,802	-601,799	-1,922,957		-2,524,756	4
							5
	1,175,660	1,204,996	-244,603	-961,156		-1,205,759	6
-5,249		5,249		-107,338		-107,338	7
-4,305		4,305		-88,029		-88,029	8
							9
-1,750		1,750		-35,779		-35,779	10
295,129			8,152,335	6,982,304		15,134,639	11
							12
			-15,563	-146,869		-162,432	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
536,248			10,514,291	21,181,688		31,695,979	1
							2
				17,510		17,510	3
							4
770			10,589	34,474		45,063	5
				-18		-18	6
			107,748			107,748	7
5,426,920				207,448,017		207,448,017	8
				-378,393		-378,393	9
3,005				76,115		76,115	10
4,060				118,087		118,087	11
80,216			1,935,375	2,272,337		4,207,712	12
							13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
				-1,402		-1,402	1
							2
5,097			251,870	235,910		487,780	3
							4
1,077,632				47,775,010		47,775,010	5
1,112				24,839		24,839	6
12,060				763,700		763,700	7
			52,770			52,770	8
32,750				876,100		876,100	9
							10
547,864				19,867,687		19,867,687	11
							12
232,515				8,833,120		8,833,120	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	
140,568			3,913,276	3,353,675		7,266,951	1
							2
			-11,138	-75,826		-86,964	3
							4
88,744				2,609,446		2,609,446	5
864,902				51,043,419		51,043,419	6
				127,755		127,755	7
3,285				87,525		87,525	8
6,000				302,000		302,000	9
				39,326		39,326	10
							11
				2,934		2,934	12
							13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
93,336				4,275,516		4,275,516	1
-124				-1,240		-1,240	2
30,841				1,603,241		1,603,241	3
1,167				38,483		38,483	4
			7,008			7,008	5
			238,272			238,272	6
3,340				157,398		157,398	7
							8
2,817				57,537		57,537	9
31,933				1,027,867		1,027,867	10
				978,899		978,899	11
18,747				430,121		430,121	12
							13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
5,004				217,425		217,425	1
							2
20,425				913,416		913,416	3
	44			2,542		2,542	4
	-2,920			-185,206		-185,206	5
	1,789			-1,123,185		-1,123,185	6
							7
	-11,956			-298,575		-298,575	8
	-1,465			88,534		88,534	9
	-379			-25,648		-25,648	10
	40,010			1,735,014		1,735,014	11
				11,018		11,018	12
							13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
				2,236		2,236	1
				216		216	2
				6,836		6,836	3
				66		66	4
				30,226		30,226	5
				21		21	6
				80,150		80,150	7
				1,346		1,346	8
				8,565		8,565	9
				564		564	10
				12,216		12,216	11
				25		25	12
				81,643		81,643	13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
				282		282	1
				436		436	2
				4,899		4,899	3
				149		149	4
	129,753	127,782					5
							6
							7
							8
							9
							10
							11
							12
							13
							14
11,131,534	7,750,015	7,979,866	23,576,626	477,778,233		501,354,859	

Schedule Page: 326 Line No.: 1 Column: c

(1) This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the North Carolinas Utilites Commsiion and the South Carolinas Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326.24 Line No.: 1 Column: c

(2) Purchase from this company is done pursuant to a Market Rate tariff of purchaser.

Schedule Page: 326.27 Line No.: 7 Column: c

(3) Settlement for imbalance exchange.

Schedule Page: 326.28 Line No.: 4 Column: c

(4) Settlement for imbalance exchange.

Schedule Page: 326.30 Line No.: 5 Column: c

(5) The Operation Regulation refers to MWHs scheduled in versus MWHs scheduled out of the Duke Balancing Authority.

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 Classification (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	Carolina Power & Light	Various	Various	LFP
6	Carolina Power & Light	Various	Various	LFP
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	OS
11	Carolina Power & Light	Various	Various	SFP
12	EDF Trading North America	Various	Various	OS
13	EDF Trading North America	Various	Various	SFP
14	Endure Energy LLC	Various	Various	OS
15	Exelon Power Team	Various	Various	OS
16	Exelon Power Team	Various	Various	SFP
17	FPLEMT (Regulated Marketing Arm of FP&L)	Various	Various	OS
18	Florida Power Corp	Various	Various	OS
19	Macquarie Energy LLC	Various	Various	OS
20	Macquarie Energy LLC	Various	Various	SFP
21	Mercuria Energy America Inc	Various	Various	SFP
22	Mercuria Energy America Inc	Various	Various	OS
23	Morgan Stanley Capital Group Inc	Various	Various	OS
24	Morgan Stanley Capital Group Inc	Various	Various	SFP
25	NC Electric Membership Corporation	Various	Various	LFP
26	NC Electric Membership Corporation	Various	Various	LFP
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	OS
31	NC Electric Membership Corporation	Various	Various	SFP
32	NCMPA	Various	Various	OS
33	NCMPA	Various	Various	SFP
34	NTE Carolinas LLC	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	NTE Carolinas LLC	Various	Various	SFP
2	Oglethorpe	Various	Various	OS
3	Rainbow Energy Marketing	Various	Various	OS
4	Rainbow Energy Marketing	Various	Various	SFP
5	South Carolina Electric & Gas Company	Various	Various	SFP
6	South Carolina Public Service Authority - P2P	Various	Various	LFP
7	South Carolina Public Service Authority - P2P	Various	Various	LFP
8	South Carolina Public Service Authority - P2P	Various	Various	OS
9	South Carolina Public Service Authority - P2P	Various	Various	SFP
10	Southern Wholesale	Various	Various	OS
11	Southern Wholesale	Various	Various	SFP
12	Tenaska Power Services Co.	Various	Various	OS
13	Tennessee Valley Authority	Various	Various	OS
14	Tennessee Valley Authority	Various	Various	SFP
15	The Energy Authority	Various	Various	OS
16	The Energy Authority	Various	Various	SFP
17	Westar Energy	Various	Various	OS
18	Westar Energy	Various	Various	SFP
19	Point to Point MWH(s) for all entries above			
20	Blue Ridge Electric Membership Corporation	Various	Various	FNO
21	Central Electric Power Cooperative Inc.	Various	Various	FNO
22	City of Concord	Various	Various	FNO
23	City of Kings Mountain	Various	Various	FNO
24	City of Seneca	Various	Various	FNO
25	EnergyUnited Electric Membership	Various	Various	FNO
26	Greenwood Commissioners of Public Works	Various	Various	FNO
27	Haywood Electric Membership Corporation	Various	Various	FNO
28	Lockhart Power Company	Various	Various	FNO
29	Macquarie Energy LLC	Various	Various	FNO
30	NC Electric Membership Corporation	Various	Various	FNO
31	NCMPA	Various	Various	FNO
32	Piedmont Electric Membership Corporation	Various	Various	FNO
33	Piedmont Municipal Power Agency	Various	Various	FNO
34	Rutherford Electric Membership Corporation	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	SCE&G COMPANY	Various	Various	FNO
2	South Carolina Public Service Authority -	Various	Various	FNO
3	Southern Power Company - Rowan Plant	Various	Various	FNO
4	Town of Dallas	Various	Various	FNO
5	Town of Due West	Various	Various	FNO
6	Town of Forest City	Various	Various	FNO
7	Town of Highlands	Various	Various	FNO
8	Town of Prosperity	Various	Various	FNO
9	US Department of Energy	Various	Various	FNO
10	Western Carolina University	Various	Various	FNO
11	Revenue Accrual	Various	Various	
12				
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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
454	Various	Various	99			1
454	Various	Various	200			2
444	Various	Various				3
443	Various	Various				4
401	Various	Various	850			5
382	Various	Various	150			6
470	Various	Various	150			7
390	Various	Various	100			8
405	Various	Various	300			9
35	Various	Various				10
163	Various	Various				11
319	Various	Various				12
318	Various	Various				13
412	Various	Various				14
195	Various	Various				15
194	Various	Various				16
149	Various	Various				17
292	Various	Various				18
486	Various	Various				19
485	Various	Various				20
475	Various	Various				21
476	Various	Various				22
19	Various	Various				23
308	Various	Various				24
389D	Various	Various	50			25
474	Various	Various	100			26
472	Various	Various	50			27
471	Various	Various	55			28
	Various	Various	50			29
334	Various	Various				30
387	Various	Various				31
134	Various	Various				32
152	Various	Various				33
489	Various	Various				34
			2,186	**37,757,456**	**37,679,553**	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
490	Various	Various				1
38	Various	Various				2
4	Various	Various				3
341	Various	Various				4
340	Various	Various				5
452	Various	Various	10			6
483	Various	Various	22			7
356	Various	Various				8
357	Various	Various				9
12	Various	Various				10
161	Various	Various				11
60	Various	Various				12
7	Various	Various				13
215	Various	Various				14
48	Various	Various				15
306	Various	Various				16
279	Various	Various				17
278	Various	Various				18
				14,946,678	14,869,255	19
	Various	Various		1,453,506	1,453,506	20
	Various	Various		3,649,301	3,649,301	21
	Various	Various		1,013,864	1,013,864	22
	Various	Various		158,863	158,863	23
	Various	Various		159,642	159,642	24
	Various	Various		2,891,205	2,891,205	25
	Various	Various		327,747	327,747	26
	Various	Various		135,303	135,303	27
	Various	Various		245,858	245,858	28
	Various	Various				29
	Various	Various		2,229,489	2,229,489	30
	Various	Various		5,520,635	5,520,635	31
	Various	Various		418,624	418,624	32
	Various	Various		2,465,303	2,465,303	33
	Various	Various		1,374,489	1,374,489	34
			2,186	**37,757,456**	**37,679,553**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
	Various	Various		5,482	5,482	1
	Various	Various		417,397	417,397	2
	Various	Various				3
	Various	Various		76,391	76,391	4
	Various	Various		13,851	13,851	5
	Various	Various		119,148	119,148	6
	Various	Various		52,374	52,374	7
	Various	Various		12,824	12,824	8
	Various	Various		22,452	21,972	9
	Various	Various		47,030	47,030	10
	Various	Various				11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			2,186	**37,757,456**	**37,679,553**	

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.
1,936,935	27,807		1,964,742	1
3,913,000			3,913,000	2
		117,259	117,259	3
		273,593	273,593	4
				5
				6
				7
				8
51			51	9
		-277,687	-277,687	10
		-6,868	-6,868	11
		215,648	215,648	12
		64,404	64,404	13
	1,424	13,325	14,749	14
		384,293	384,293	15
		1,193,913	1,193,913	16
		5,592	5,592	17
		56,280	56,280	18
	164,785	693,425	858,210	19
	993,912	3,900,158	4,894,070	20
		46,752	46,752	21
		106,749	106,749	22
		633,393	633,393	23
		383,806	383,806	24
978,250			978,250	25
				26
				27
				28
949,500			949,500	29
		153,831	153,831	30
		56,759	56,759	31
		1,107,219	1,107,219	32
		572,104	572,104	33
		818,064	818,064	34
61,965,679	**1,189,316**	**31,049,330**	**94,204,325**	

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.
	962	1,446,311	1,447,273	1
		232	232	2
		4,475	4,475	3
		16,020	16,020	4
		7,502	7,502	5
189,907			189,907	6
				7
		262,437	262,437	8
		153,790	153,790	9
		2,928,594	2,928,594	10
		2,827,468	2,827,468	11
		1,711	1,711	12
		12,478	12,478	13
	426	97,049	97,475	14
		321,345	321,345	15
		43,119	43,119	16
		74,385	74,385	17
		3,758	3,758	18
				19
3,417,763		1,161,961	4,579,724	20
9,296,719		3,133,065	12,429,784	21
2,312,504		785,660	3,098,164	22
337,027		114,398	451,425	23
405,904		83,439	489,343	24
7,713,600		1,588,676	9,302,276	25
764,188		259,534	1,023,722	26
332,495		113,087	445,582	27
852,362		289,603	1,141,965	28
				29
6,136,164		273,797	6,409,961	30
11,379,379		1,527,470	12,906,849	31
1,170,158		397,757	1,567,915	32
5,898,443		936,700	6,835,143	33
3,808,539		1,294,240	5,102,779	34
61,965,679	**1,189,316**	**31,049,330**	**94,204,325**	

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.
14,902		5,077	19,979	1
1,696,547		342,760	2,039,307	2
		-311,067	-311,067	3
167,319		56,852	224,171	4
31,226		10,613	41,839	5
257,131		87,231	344,362	6
122,384		41,594	163,978	7
24,373		8,286	32,659	8
294,062		95,017	389,079	9
120,351		40,894	161,245	10
-2,555,504			-2,555,504	11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
61,965,679	**1,189,316**	**31,049,330**	**94,204,325**	

Schedule Page: 328 Line No.: 1 Column: h

This long term firm transaction with Brookfield Energy Marketing expires 6/30/19.

Schedule Page: 328 Line No.: 1 Column: k

Demand charges include long term firm transmission for prior period adjustments resulting from a change in revenue requirement for transmission and schedule 1.

Schedule Page: 328 Line No.: 1 Column: l

Energy charges include loss compensation.

Schedule Page: 328 Line No.: 2 Column: h

This long term firm transaction with Brookfield Energy Marketing expires 6/30/19.

Schedule Page: 328 Line No.: 2 Column: k

Demand charges include long term firm transmission for prior period adjustments resulting from a change in revenue requirement for transmission and schedule 1.

Schedule Page: 328 Line No.: 3 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 4 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 5 Column: a

Carolina Power & Light is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 5 Column: h

This long term firm transaction with Carolina Power & Light expires 6/30/23.

Schedule Page: 328 Line No.: 6 Column: a

Carolina Power & Light is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 6 Column: h

This long term firm transaction with Carolina Power & Light expires 12/31/19.

Schedule Page: 328 Line No.: 7 Column: a

Carolina Power & Light is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 7 Column: h

This long term firm transaction with Carolina Power & Light expires 12/31/20.

Schedule Page: 328 Line No.: 8 Column: a

Carolina Power & Light is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 8 Column: h

This long term firm transaction with Carolina Power & Light expires 12/31/22.

Schedule Page: 328 Line No.: 9 Column: a

Carolina Power & Light is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 9 Column: h

This long term firm transaction with Carolina Power & Light expires 12/31/34.

Schedule Page: 328 Line No.: 9 Column: k

Demand charges include long term firm transmission for prior period adjustments resulting from a change in revenue requirement for transmission and schedule 1.

Schedule Page: 328 Line No.: 10 Column: a

Carolina Power & Light is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 10 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 11 Column: a

Carolina Power & Light is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 11 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 12 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 13 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 14 Column: l

Energy charges include loss compensation.

Schedule Page: 328 Line No.: 14 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 15 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 16 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 17 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 18 Column: a

Florida Power Corp is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 18 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 19 Column: l

Energy charges include loss compensation.

Schedule Page: 328 Line No.: 19 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 20 Column: l

Energy charges include loss compensation.

Schedule Page: 328 Line No.: 20 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 21 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 22 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 23 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 24 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 25 Column: h

This long term firm transaction with NCEMC expires 9/30/19.

Schedule Page: 328 Line No.: 25 Column: k

Demand charges include long term firm transmission for prior period adjustments resulting from a change in revenue requirement for transmission and schedule 1.

Schedule Page: 328 Line No.: 26 Column: h

This long term firm transaction with NCEMC expires 12/31/20.

Schedule Page: 328 Line No.: 27 Column: h

This long term firm transaction with NCEMC expires 12/31/21.

Schedule Page: 328 Line No.: 28 Column: h

This long term firm transaction with NCEMC expires 12/31/21.

Schedule Page: 328 Line No.: 29 Column: h

This long term firm transaction with NCEMC expires 12/31/22.

Schedule Page: 328 Line No.: 29 Column: k

Demand charges include long term firm transmission for prior period adjustments resulting from a change in revenue requirement for transmission and schedule 1.

Schedule Page: 328 Line No.: 30 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 31 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 32 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 33 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 34 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 1 Column: l

Energy charges include loss compensation.

Schedule Page: 328.1 Line No.: 1 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 2 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 3 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 4 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 5 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 6 Column: h

This long term firm transaction with SCPSA expires 12/31/18.

Schedule Page: 328.1 Line No.: 6 Column: k

Demand charges include long term firm transmission for prior period adjustments resulting from a change in revenue requirement for transmission and schedule 1.

Schedule Page: 328.1 Line No.: 7 Column: h

This long term firm transaction with SCPSA expires 12/31/21.

Schedule Page: 328.1 Line No.: 8 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 9 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 10 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 11 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 12 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 13 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 14 Column: l

Energy charges include loss compensation.

Schedule Page: 328.1 Line No.: 14 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 15 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 16 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 17 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 18 Column: m

Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 20 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 22 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 23 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 24 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 26 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 27 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 28 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 30 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 31 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 32 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 33 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 34 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 2 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 4 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 5 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 6 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 7 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 8 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 9 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 10 Column: k

Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 11 Column: n

OATT Tax Accrual 1Q18 -2,071,085
OATT Partial Settlement Accrual 1Q18 -897,189
Rounding 1Q18 -4
OATT Accrual 2Q18 -1,892,562
OATT Tax Accrual 2Q18 -1,395,298
OATT Partial Settlement Accrual 2Q18 -601,117
Rounding 2Q18 -2
OATT Accrual 3Q18 -273,603
Reverse OATT partial settlement accrual 3Q18 3,598,306
Accrual Recovery of Florence Storm Costs 3Q18 3,600,000
CBIS Journal 3Q18 50
Rounding 3Q18 -1
Storm Accrual Adjustment 4Q18 -1,184,699
OATT Accrual 4Q18 -819,290
OATT Settlement Accrual 4Q18 -619,012
Rounding 4Q18 2

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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					
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	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	NCMPA	OS			25,592			25,592
2	NCEMC	OS			41,890			41,890
3	Energy United	OS			112,779			112,779
4	Carolina Power & Light	NF				2,512,867	7,343	2,520,210
5	Carolina Power & Light	SFP				29,438	2,503	31,941
6	Central Electric	OS			303,212			303,212
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL				483,473	2,542,305	9,846	3,035,624

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,037,568
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,878,675
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	107,541
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	-33,831,814
6	Dues and Subscriptions to various organizations:	
7	Agribusiness Henderson County	500
8	Alamance County CoC	1,100
9	American Society of Corporate Executives	6,860
10	Anderson Area CoC	2,493
11	Association of Corporate Contributions	2,213
12	Association of Edison Illuminating Companies	6,021
13	Belmont CoC	810
14	Better Business Bureau of Central North Carolina	955
15	Burke County CoC	3,250
16	Cabarrus Regional CoC	5,200
17	Caldwell County CoC	545
18	Catawba County CoC	5,000
19	Center for Climate and Energy Solutions	12,394
20	Chamber of Commerce of the USA	66,394
21	Chapel Hill Carrboro CoC	3,861
22	CharIN	11,632
23	Charlotte CoC	50,000
24	Cherokee CoC (NC)	2,980
25	Chester Country CoC	1,250
26	Clemson Area CoC	868
27	Cleveland County CoC	872
28	Dan River Basin Association	500
29	Downtown Durham Inc.	2,500
30	Downtown Winston Salem Partnership	500
31	E4 Carolinas	14,164
32	Eden CoC	1,670
33	European American CoC	1,000
34	European American Investment Council LP	4,675
35	Gaston Regional CoC	1,452
36	Greater Durham CoC	9,300
37	Greater Easley CoC	893
38	Greater Greer CoC	518
39	Greater Winston Salem CoC	11,820
40	Greater York CoC	3,300
41	Greensboro CoC	12,934
42	Greenville Arts Festival (named as Artisphere)	1,000
43	Greenville CoC	27,200
44	Greenwood CoC	986
45	GridWise	4,751
46	TOTAL	-26,059,961

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Henderson County CoC	1,258
7	Henderson County Partners for Economic Progress	1,200
8	Hickory Nut Gorge CoC	500
9	High Point CoC	3,500
10	Hillsborough/Orange County CoC	3,000
11	Jackson County CoC	500
12	Kernersville CoC	905
13	Keystone Policy Center	5,312
14	King CoC	575
15	Lake Norman CoC	1,200
16	Lincolnton-Lincoln Co CoC	707
17	Matthews CoC	770
18	McDowell CoC	675
19	Mooresville-South Iredell CoC	1,082
20	Mounty Airy CoC	1,010
21	Museum of Life and Science	1,214
22	North Carolina CoC	38,000
23	Nuclear Waste Strategy Coalition	3,187
24	Palmetto Business Council	5,000
25	Polk County CoC	559
26	Reidsville CoC	585
27	Ripon Society (2017 correction)	-8,853
28	Rotary Club of Greenwood	1,000
29	Rowan County CoC	6,534
30	Rutherford CoC	750
31	Sand Hill Group	9,738
32	Simpsonsville Area CoC	1,386
33	South Carolina Association of Counties	1,000
34	South Carolina CoC	31,000
35	Spartanburg Area CoC	15,222
36	Spartanburg County Municipal Association	500
37	Spartanburg Development Association	1,818
38	Stanly County CoC	1,190
39	Thomasville Area CoC	1,826
40	Union County CoC	1,025
41	Utility Water Act Group	868
42	VisitGreenvilleSC	525
43	Western Rockingham CoC	880
44	Wilkes CoC	1,828
45	York County Regional CoC	3,400
46	TOTAL	-26,059,961

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Chamber of Commerce (17)	5,095
7	Miscellaneous	1,185
8		
9	Transferred Employee Homes	1,495,583
10		
11	Leased Circuit Charges	4,787
12		
13	Director's Fees and Expenses	1,814,682
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		
45		
46	TOTAL	-26,059,961

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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			65,733,147		65,733,147
2	Steam Production Plant	265,841,037				265,841,037
3	Nuclear Production Plant	244,414,587				244,414,587
4	Hydraulic Production Plant-Conventional	19,938,271				19,938,271
5	Hydraulic Production Plant-Pumped Storage	19,731,887				19,731,887
6	Other Production Plant	82,415,036				82,415,036
7	Transmission Plant	81,237,943				81,237,943
8	Distribution Plant	254,752,847				254,752,847
9	Regional Transmission and Market Operation					
10	General Plant	61,214,590		127,399		61,341,989
11	Common Plant-Electric					
12	TOTAL	1,029,546,198		65,860,546		1,095,406,744

B. Basis for Amortization Charges

Limited term electric depreciable plant base is $384,238,284, 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 5 years. The generating plant reclicensing 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	311 - Allen	126,143	100.00	-0.05	4.73	S1	9.50
13	311 - Belews Creek	314,667	100.00	-0.07	3.07	S1	20.20
14	311 - Cliffside 5	62,251	100.00	-0.05	3.53	S1	15.30
15	311 - Cliffside 5&6	25,374	100.00	-0.05	3.11	S1	31.10
16	311 - Cliffside 6	156,229	100.00	-0.06	2.95	S1	31.00
17	311 - Lee	34,020	100.00	-0.11	3.19	S1	13.30
18	311 - Marshall	137,455	100.00	-0.05	3.14	S1	17.20
19	311 - Not Station Speci	28,467	100.00	-0.20	2.76	S1	30.50
20	312 - Allen	859,794	50.00	-0.05	3.70	R2	9.30
21	312 - Belews Creek	1,504,388	50.00	-0.07	2.96	R2	19.40
22	312 - Cliffside 5	587,895	50.00	-0.05	3.66	R2	15.00
23	312 - Cliffside 5&6	13,297	50.00	-0.05	2.89	R2	28.80
24	312 - Cliffside 6	1,242,767	50.00	-0.06	2.99	R2	29.00
25	312 - Lee	46,799	50.00	-0.11	3.76	R2	13.20
26	312 - Marshall	1,233,692	50.00	-0.05	3.28	R2	16.80
27	312 - Not Station Speci	1,215	50.00	-0.15	3.26	R2	29.00
28	314 - Allen	144,858	55.00	-0.05	7.66	R1.5	9.20
29	314 - Belews Creek	232,824	55.00	-0.07	3.95	R1.5	19.20
30	314 - Cliffside 5	60,148	55.00	-0.05	4.30	R1.5	14.60
31	314 - Cliffside 6	268,625	55.00	-0.06	3.26	R1.5	28.80
32	314 - Lee	8,933	55.00	-0.11	3.39	R1.5	11.60
33	314 - Marshall	204,174	55.00	-0.05	4.31	R1.5	16.40
34	314 - Not Station Speci	535	55.00	-0.05	3.20	R1.5	28.80
35	315 - Allen	56,960	60.00	-0.05	4.42	S1	9.20
36	315 - Belews Creek	67,728	60.00	-0.07	3.35	S1	19.20
37	315 - Cliffside 5	23,487	60.00	-0.05	3.46	S1	14.60
38	315 - Cliffside 6	153,517	60.00	-0.06	3.11	S1	29.70
39	315 - Lee	16,728	60.00	-0.11	3.52	S1	12.70
40	315 - Marshall	75,552	60.00	-0.05	3.45	S1	16.50
41	316 - Allen	21,355	50.00	-0.05	6.85	R2.5	9.30
42	316 - Belews Creek	28,325	50.00	-0.07	4.09	R2.5	19.50
43	316 - Cliffside 5	12,732	50.00	-0.05	4.87	R2.5	15.00
44	316 - Cliffside 5&6	6,553	50.00	-0.05	3.38	R2.5	29.90
45	316 - Cliffside 6	247,478	50.00	-0.06	3.20	R2.5	29.50
46	316 - Lee	6,288	50.00	-0.11	5.39	R2.5	13.00
47	316 - Marshall	34,633	50.00	-0.05	4.56	R2.5	16.80
48	316 - Not Station Speci	5,444	50.00	-0.05	3.33	R2.5	29.80
49	320 - Catawba	457	100.00		1.85	R4	26.70
50	320 - McGuire	75	100.00		1.65	R4	25.80

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	320 - Oconee	425	100.00		1.55	R4	17.20
13	321 - Catawba	244,387	55.00	-0.04	2.40	S1.5	22.50
14	321 - McGuire	688,681	55.00	-0.04	2.48	S1.5	22.10
15	321 - Oconee	962,117	55.00	-0.01	4.01	S1.5	17.00
16	322 - Catawba	369,588	50.00	-0.04	2.41	R2	22.50
17	322 - McGuire	1,548,018	50.00	-0.04	2.49	R2	22.20
18	322 - Oconee	1,933,323	50.00	-0.01	4.08	R2	16.80
19	323 - Catawba	96,944	50.00	-0.04	2.55	R1.5	21.90
20	323 - McGuire	556,468	50.00	-0.04	3.27	R1.5	23.30
21	323 - Oconee	323,062	50.00	-0.01	3.81	R1.5	16.30
22	324 - Catawba	81,525	50.00	-0.04	2.66	R2.5	22.20
23	324 - McGuire	253,764	50.00	-0.04	2.70	R2.5	21.50
24	324 - Oconee	882,269	50.00	-0.01	4.64	R2.5	17.10
25	325 - Catawba	49,228	50.00	-0.04	2.62	R2.5	23.90
26	325 - McGuire	279,809	50.00	-0.04	2.74	R2.5	23.40
27	325 - Not Station Speci	1,446	50.00	-0.02	3.66	R2.5	25.90
28	325 - Oconee	233,378	50.00	-0.01	3.52	R2.5	16.80
29	330 - Bad Creek	724	110.00		1.23	R4	41.00
30	330 - Cowans Ford	6,882	110.00		0.66	R4	36.10
31	330 - Jocassee	436	110.00		0.86	R4	29.00
32	330 - Keowee	12,071	110.00		0.72	R4	28.70
33	330 - Oxford	696	110.00		0.06	R4	26.30
34	331 - 99 Island	1,508	75.00	-0.18	2.75	S2	19.10
35	331 - Bad Creek	227,996	75.00	-0.06	1.55	S2	36.10
36	331 - Bear Creek	1,004	75.00	-0.29	4.72	S2	24.30
37	331 - Bridgewater	65,117	75.00	-0.04	2.34	S2	37.60
38	331 - Bryson City	19	75.00	-0.27	0.90	S2	18.20
39	331 - Cedar Cliff	1,550	75.00	-0.22	4.36	S2	24.40
40	331 - Cedar Creek	3,990	75.00	-0.18	2.16	S2	26.10
41	331 - Cowans Ford	16,442	75.00	-0.13	1.77	S2	33.80
42	331 - Dearborn	2,137	75.00	-0.22	2.00	S2	35.20
43	331 - Fishing Creek	4,376	75.00	-0.16	2.16	S2	36.30
44	331 - Franklin	942	75.00	-0.20	4.36	S2	24.40
45	331 - Gaston Shoals	1,667	75.00	-0.15	3.92	S2	19.40
46	331 - Great Falls	436	75.00	-0.97	1.85	S2	36.80
47	331 - Jocassee	28,242	75.00	-0.04	1.62	S2	26.60
48	331 - Keowee	8,237	75.00	-0.05	2.72	S2	28.90
49	331 - Lookout Shoals	2,536	75.00	-0.22	2.07	S2	35.50
50	331 - Mission	326	75.00	-0.31	4.06	S2	24.30

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	331 - Mtn Island	3,348	75.00	-0.23	2.37	S2	36.60
13	331 - Nantahala	2,174	75.00	-0.13	3.26	S2	25.00
14	331 - Not Station Speci	28	75.00	-0.20	3.24	S2	25.20
15	331 - Oxford	4,113	75.00	-0.10	1.93	S2	35.90
16	331 - Queens Creek	112	75.00	-0.73	8.03	S2	15.50
17	331 - Rhodhiss	4,003	75.00	-0.15	2.10	S2	36.20
18	331 - Tennessee Creek	356	75.00	-0.18	2.84	S2	23.60
19	331 - Thorpe	2,897	75.00	-0.19	3.43	S2	24.00
20	331 - Tuckasegee	2,378	75.00	-0.31	4.57	S2	24.40
21	331 - Tuxedo	1,023	75.00	-0.17	3.95	S2	24.30
22	331 - Wateree	9,061	75.00	-0.16	2.00	S2	35.50
23	331 - Wylie	6,476	75.00	-0.16	2.03	S2	35.90
24	332 - 99 Island	11,666	100.00	-0.18	2.70	S2.5	19.50
25	332 - Bad Creek	455,305	100.00	-0.06	1.33	S2.5	40.00
26	332 - Bear Creek	3,654	100.00	-0.29	0.61	S2.5	23.10
27	332 - Bridgewater	105,399	100.00	-0.04	2.05	S2.5	38.30
28	332 - Bryson City	2,839	100.00	-0.27	4.67	S2.5	24.50
29	332 - Cedar Cliff	2,112	100.00	-0.22	1.12	S2.5	24.00
30	332 - Cedar Creek	11,561	100.00	-0.18	2.11	S2.5	38.10
31	332 - Cowans Ford	34,531	100.00	-0.13	1.54	S2.5	36.90
32	332 - Dearborn	1,506	100.00	-0.22	1.51	S2.5	37.90
33	332 - Fishing Creek	15,283	100.00	-0.16	1.81	S2.5	38.00
34	332 - Franklin	5,461	100.00	-0.20	4.44	S2.5	24.50
35	332 - Gaston Shoals	6,357	100.00	-0.15	2.44	S2.5	19.50
36	332 - Great Falls	2,869	100.00	-0.97	1.74	S2.5	37.30
37	332 - Jocassee	49,702	100.00	-0.04	0.84	S2.5	27.80
38	332 - Keowee	17,440	100.00	-0.05	0.84	S2.5	27.70
39	332 - Lookout Shoals	5,618	100.00	-0.22	1.44	S2.5	37.80
40	332 - Mission	1,812	100.00	-0.31	2.96	S2.5	24.40
41	332 - Mtn Island	5,532	100.00	-0.23	1.09	S2.5	37.90
42	332 - Nantahala	13,262	100.00	-0.13	0.73	S2.5	24.90
43	332 - Not Station Speci	325	100.00	-0.20	2.17	S2.5	25.30
44	332 - Oxford	30,621	100.00	-0.10	1.78	S2.5	38.00
45	332 - Queens Creek	763	100.00	-0.73	4.69	S2.5	15.50
46	332 - Rhodhiss	7,547	100.00	-0.15	1.64	S2.5	37.90
47	332 - Tennessee Creek	4,890	100.00	-0.18	1.37	S2.5	24.00
48	332 - Thorpe	4,897	100.00	-0.19	0.03	S2.5	21.10
49	332 - Tuckasegee	638	100.00	-0.31	0.25	S2.5	21.30
50	332 - Tuxedo	6,432	100.00	-0.17	1.86	S2.5	24.30

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	332 - Wateree	14,982	100.00	-0.16	1.46	S2.5	37.80
13	332 - Wylie	21,367	100.00	-0.16	1.67	S2.5	38.00
14	333 - 99 Island	10,666	70.00	-0.18	3.73	S1	19.00
15	333 - Bad Creek	238,770	70.00	-0.06	1.66	S1	34.00
16	333 - Bear Creek	6,568	70.00	-0.29	1.46	S1	20.10
17	333 - Bridgewater	20,786	70.00	-0.04	2.44	S1	36.10
18	333 - Bryson City	3,331	70.00	-0.27	4.86	S1	24.10
19	333 - Cedar Cliff	3,353	70.00	-0.22	4.17	S1	23.90
20	333 - Cedar Creek	12,254	70.00	-0.18	2.14	S1	33.80
21	333 - Cowans Ford	49,634	70.00	-0.13	2.11	S1	33.70
22	333 - Dearborn	11,865	70.00	-0.22	2.26	S1	33.90
23	333 - Fishing Creek	22,175	70.00	-0.16	2.10	S1	33.70
24	333 - Franklin	1,341	70.00	-0.20	3.94	S1	23.90
25	333 - Gaston Shoals	10,103	70.00	-0.15	4.81	S1	19.20
26	333 - Great Falls	5,339	70.00	-0.97	3.14	S1	33.00
27	333 - Jocassee	70,981	70.00	-0.04	2.38	S1	27.50
28	333 - Keowee	72,562	70.00	-0.05	2.89	S1	28.30
29	333 - Lookout Shoals	10,625	70.00	-0.22	2.33	S1	34.20
30	333 - Mission	5,815	70.00	-0.31	4.82	S1	24.10
31	333 - Mtn Island	16,300	70.00	-0.23	2.43	S1	34.70
32	333 - Nantahala	3,921	70.00	-0.13	2.68	S1	24.10
33	333 - Not Station Speci	1	70.00	-0.25	3.59	S1	24.40
34	333 - Oxford	18,482	70.00	-0.10	2.28	S1	35.00
35	333 - Queens Creek	38	70.00	-0.73	1.03	S1	13.20
36	333 - Rhodhiss	16,393	70.00	-0.15	2.57	S1	35.70
37	333 - Tennessee Creek	2,167	70.00	-0.18	3.96	S1	23.90
38	333 - Thorpe	820	70.00	-0.19	2.56	S1	22.80
39	333 - Tuckasegee	137	70.00	-0.31	1.14	S1	18.30
40	333 - Tuxedo	1,996	70.00	-0.17	3.74	S1	23.90
41	333 - Wateree	23,377	70.00	-0.16	2.07	S1	33.60
42	333 - Wylie	17,446	70.00	-0.16	2.02	S1	33.30
43	334 - 99 Island	640	65.00	-0.18	4.00	S1	18.60
44	334 - Bad Creek	51,304	65.00	-0.06	1.91	S1	32.90
45	334 - Bear Creek	122	65.00	-0.29	2.89	S1	21.50
46	334 - Bridgewater	7,383	65.00	-0.04	2.52	S1	35.60
47	334 - Bryson City	15	65.00	-0.27	3.13	S1	21.40
48	334 - Cedar Cliff	109	65.00	-0.22	3.04	S1	22.20
49	334 - Cedar Creek	3,549	65.00	-0.18	2.46	S1	33.50
50	334 - Cowans Ford	7,015	65.00	-0.13	2.43	S1	33.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	334 - Dearborn	3,821	65.00	-0.22	2.47	S1	33.00
13	334 - Fishing Creek	4,752	65.00	-0.16	2.34	S1	32.90
14	334 - Franklin	120	65.00	-0.20	3.70	S1	23.20
15	334 - Gaston Shoals	2,110	65.00	-0.15	3.22	S1	18.40
16	334 - Great Falls	853	65.00	-0.97	3.42	S1	29.00
17	334 - Jocassee	13,831	65.00	-0.04	2.13	S1	25.20
18	334 - Keowee	21,431	65.00	-0.05	2.49	S1	26.90
19	334 - Lookout Shoals	2,113	65.00	-0.22	2.40	S1	32.30
20	334 - Mission	51	65.00	-0.31	3.06	S1	21.70
21	334 - Mtn Island	2,671	65.00	-0.23	2.63	S1	33.60
22	334 - Nantahala	2,140	65.00	-0.13	2.99	S1	23.80
23	334 - Oxford	3,767	65.00	-0.10	2.14	S1	32.40
24	334 - Queens Creek	183	65.00	-0.73	5.02	S1	14.80
25	334 - Rhodhiss	2,251	65.00	-0.15	2.32	S1	32.80
26	334 - Tennessee Creek	195	65.00	-0.18	2.86	S1	22.10
27	334 - Thorpe	2,075	65.00	-0.19	2.93	S1	22.50
28	334 - Tuckasegee	243	65.00	-0.31	3.10	S1	22.30
29	334 - Tuxedo	907	65.00	-0.17	3.69	S1	23.40
30	334 - Wateree	5,384	65.00	-0.16	2.31	S1	32.80
31	334 - Wylie	3,930	65.00	-0.16	2.39	S1	33.00
32	335 - 99 Island	379	55.00	-0.18	3.88	R2	18.40
33	335 - Bad Creek	28,311	55.00	-0.06	2.09	R2	31.50
34	335 - Bear Creek	166	55.00	-0.29	3.80	R2	22.20
35	335 - Bridgewater	7,375	55.00	-0.04	2.60	R2	34.70
36	335 - Bryson City	106	55.00	-0.27	4.50	R2	12.30
37	335 - Cedar Cliff	124	55.00	-0.22	3.59	R2	22.10
38	335 - Cedar Creek	499	55.00	-0.18	2.83	R2	33.60
39	335 - Cowans Ford	1,685	55.00	-0.13	2.56	R2	32.50
40	335 - Dearborn	246	55.00	-0.22	2.56	R2	31.00
41	335 - Fishing Creek	320	55.00	-0.16	2.67	R2	32.90
42	335 - Franklin	110	55.00	-0.20	3.94	R2	23.10
43	335 - Gaston Shoals	287	55.00	-0.15	4.60	R2	18.80
44	335 - Great Falls	266	55.00	-0.97	4.33	R2	31.90
45	335 - Jocassee	3,910	55.00	-0.04	2.63	R2	25.20
46	335 - Keowee	857	55.00	-0.05	2.23	R2	23.50
47	335 - Lookout Shoals	452	55.00	-0.22	2.64	R2	31.80
48	335 - Mission	67	55.00	-0.31	4.72	R2	23.20
49	335 - Mtn Island	484	55.00	-0.23	2.79	R2	32.50
50	335 - Nantahala	1,194	55.00	-0.13	3.51	R2	23.60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	335 - Not Station Speci	812	55.00	-0.05	2.95	R2	23.50
13	335 - Oxford	647	55.00	-0.10	2.48	R2	32.60
14	335 - Queens Creek	202	55.00	-0.73	5.93	R2	14.90
15	335 - Rhodhiss	498	55.00	-0.15	2.59	R2	32.50
16	335 - Tennessee Creek	225	55.00	-0.18	3.77	R2	22.70
17	335 - Thorpe	1,480	55.00	-0.19	4.10	R2	22.90
18	335 - Tuckasegee	98	55.00	-0.31	3.96	R2	22.20
19	335 - Tuxedo	222	55.00	-0.17	3.30	R2	22.50
20	335 - Wateree	500	55.00	-0.16	2.57	R2	32.50
21	335 - Wylie	606	55.00	-0.16	2.63	R2	32.80
22	336 - Bad Creek	17,870	75.00	-0.06	1.52	R4	38.40
23	336 - Bear Creek	53	75.00	-0.29	0.96	R4	16.60
24	336 - Cedar Cliff	130	75.00	-0.22	2.00	R4	23.30
25	336 - Cowans Ford	2,240	75.00	-0.13	2.30	R4	36.90
26	336 - Dearborn	634	75.00	-0.22	1.71	R4	35.50
27	336 - Jocassee	416	75.00	-0.04	1.20	R4	25.50
28	336 - Nantahala	240	75.00	-0.13	1.45	R4	23.30
29	336 - Queens Creek	3	75.00	-0.73	0.74	R4	11.30
30	336 - Tennessee Creek	73	75.00	-0.18	0.90	R4	17.00
31	336 - Thorpe	46	75.00	-0.19	1.16	R4	21.90
32	336 - Tuckasegee	9	75.00	-0.31	0.82	R4	14.70
33	340 - Dan River CC	8	60.00		4.45	R4	10.40
34	341 - Buck	146,362	50.00	-0.03	2.80	S2	32.00
35	341 - Dan River CC	145,082	50.00	-0.03	2.79	S2	32.90
36	341 - Lee CT	829	50.00	-0.03	3.06	S2	28.90
37	341 - Lincoln CT	28,612	50.00	-0.02	3.11	S2	16.80
38	341 - Mill Creek CT	29,776	50.00	-0.02	2.83	S2	24.00
39	341 - Rockingham CT	3,360	50.00	-0.01	3.90	S2	23.00
40	342 - Buck CC	30,578	50.00	-0.03	2.62	R2.5	31.80
41	342 - Buck CC - Cap Lea	31,886	50.00		2.46	R2.5	31.70
42	342 - Dan River CC	20,398	50.00	-0.03	2.64	R2.5	32.70
43	342 - Dan River CC - Ca	9,449	50.00		2.51	R2.5	32.70
44	342 - Lincoln CT	12,585	50.00	-0.02	1.44	R2.5	17.00
45	342 - Mill Creek CT	15,066	50.00	-0.02	2.12	R2.5	24.10
46	342 - Rockingham CT	56	50.00	-0.01	3.11	R2.5	22.50
47	343 - Buck CC	135,427	40.00	-0.03	2.87	R2	29.10
48	343 - Dan River CC	151,009	40.00	-0.03	2.87	R2	29.90
49	343 - Lee CT	59,418	40.00	-0.03	2.75	R2	25.60
50	343 - Lincoln CT	254,248	40.00	-0.02	2.23	R2	16.10

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	343 - Mill Creek CT	184,152	40.00	-0.02	2.46	R2	22.00
13	343 - Rockingham CT	78,718	40.00	-0.01	3.73	R2	21.80
14	343.1 - Buck CC Rotable	33,676	5.00	0.40	8.23	R5	2.50
15	343.1 - Dan River CC Ro	36,034	5.00	0.40	10.39	R5	3.50
16	344 - Buck CC	217,976	50.00	-0.03	2.80	R2	31.10
17	344 - Dan River CC	238,323	50.00	-0.03	2.81	R2	32.00
18	344 - Lincoln CT	78,932	50.00	-0.02	2.53	R2	16.90
19	344 - Mill Creek CT	1,329	50.00	-0.02	3.52	R2	24.90
20	344 - Mocksville Solar	29,390	25.00	-0.10	4.98	S2.5	21.70
21	344 - Not Station Speci	17,730	50.00	-0.05	6.22	R2	11.30
22	344 - Rockingham CT	217,355	50.00	-0.01	2.61	R2	21.20
23	344 - Solar Generators	28,317	20.00		5.40	S2.5	13.80
24	345 - Buck CC	48,082	35.00	-0.03	3.17	S0.5	25.90
25	345 - Dan River CC	47,219	35.00	-0.03	3.21	S0.5	26.80
26	345 - Lee CT	724	35.00	-0.03	3.68	S0.5	25.40
27	345 - Lincoln CT	26,598	35.00	-0.02	2.61	S0.5	14.70
28	345 - Mill Creek CT	16,890	35.00	-0.02	2.89	S0.5	19.90
29	345 - Rockingham CT	2,131	35.00	-0.01	3.49	S0.5	19.70
30	346 - Buck CC	11,343	40.00	-0.03	2.99	S2	30.00
31	346 - Dan River CC	8,887	40.00	-0.03	2.98	S2	30.90
32	346 - Lee CT	893	40.00	-0.03	3.40	S2	28.40
33	346 - Lincoln CT	4,078	40.00	-0.02	3.56	S2	16.60
34	346 - Mill Creek CT	3,656	40.00	-0.02	3.05	S2	22.70
35	346 - Not Station Spec	79	40.00	-0.05	3.15	S2	31.80
36	346 - Rockingham CT	1,519	40.00	-0.01	3.75	S2	22.30
37	350 - Land and land rig	163,057	75.00		1.15	R4	47.00
38	352 - Structures and im	108,377	60.00	-0.20	1.96	R3	48.40
39	353 - Station equipment	1,846,896	52.00	-0.25	2.13	R1.5	40.70
40	354 - Towers and fixtur	585,522	70.00	-0.40	1.69	R2	54.10
41	355 - Poles and fixture	560,181	50.00	-0.25	2.27	R1.5	41.90
42	356 - Overhead conducto	762,266	60.00	-0.40	2.00	R2	48.10
43	357 - Underground condu	124	55.00		1.12	S4	29.40
44	358 - Underground condu	5,812	55.00		1.39	S3	42.50
45	359 - Roads and trails	42	65.00		1.46	R4	41.10
46	360 - Land and land rig	562	75.00		1.51	R3	34.60
47	360 - Land and land rig	8,873	75.00		1.37	R3	61.80
48	361 - Structures and im	113,185	60.00	-0.20	1.94	R2.5	51.60
49	362 - Station equipment	1,374,550	42.00	-0.25	2.59	R1	32.90
50	364 - Poles, towers and	1,621,625	49.00	-0.25	1.98	R2	36.70

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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	365 - Overhead conducto	2,257,465	49.00	-0.20	1.94	R0.5	41.70
13	366 - Underground condu	203,893	55.00	-0.15	1.57	R3	36.50
14	367 - Underground condu	2,031,772	54.00	-0.20	2.00	R3	40.00
15	368 - Line transformers	1,498,398	43.00		1.77	R1.5	31.90
16	369 - Services	1,103,383	50.00	-0.10	1.32	R1.5	41.80
17	370 - Meters	170,041	20.00		5.30	L0	9.10
18	3702 - AMI meters	434,933	15.00		7.19	S2.5	12.90
19	371 - Installations on	908,376	40.00	-0.05	2.16	R0.5	33.10
20	373 - Street lighting a	242,133	35.00	-0.10	2.69	R1	25.40
21	389 - Land and land rig		60.00		1.21	R3	47.00
22	389 - Land and land rig	550	60.00		1.51	R3	40.50
23	390 - Structures and im	667,230	40.00	-0.10	3.22	R2	25.70
24	391 - Office furniture	115,185	8.00		12.50	SQ	4.10
25	391 - Office furniture	48,948	15.00		6.67	SQ	8.80
26	392 - Transp. Equip - H	1,305	10.00	0.05	9.92	L2	2.10
27	392 - Transp. Equip - T	66	13.00	0.05	10.39	L3	3.60
28	392 - Transp. Equip. -	2,414	6.00	0.05	7.50	L3	5.30
29	392 - Transp. Equip. -	5,512	17.00	0.05	5.23	L0.5	7.50
30	393 - Stores equipment	14,299	20.00		5.00	SQ	14.80
31	394 - Tools, shop and g	103,302	20.00		5.00	SQ	12.60
32	395 - Laboratory equipm	5,867	15.00		6.67	SQ	6.40
33	396 - Power Operated Eq	663	14.00		4.74	S1.5	5.90
34	396 - Power operated Eq	10,272	14.00		6.54	S1.5	10.80
35	396 - Power operated eq	392	19.00		3.14	S1.5	7.00
36	397 - Communication equ	151,205	10.00		10.00	SQ	4.90
37	398 - Miscellaneous equ	10,578	20.00		5.00	SQ	12.00
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	7,009,432		7,009,432	
3	Coal Ash Management Commission Fee per NC				
4	Senate Bill 729				
5	Docket E-7, Sub 989		247,000	247,000	748,666
6	Docket E-7, Sub 1029		210,000	210,000	686,372
7	Docket E-7, Sub 1146		218,817	218,817	
8	Docket M-100, Sub 142/ Docket E-7 Sub1146		-557,157	-557,157	2,624,093
9					
10	Public Service Commission of South Carolina:				
11	SC PSC Fees	2,359,843		2,359,843	
12	Docket 2009-226-E		10,133	10,133	170,771
13	Docket 2011-271-E		15,945	15,945	371,208
14	Docket 2013-59-E		5,000	5,000	658,331
15	Docket 2015-362-E				
16					
17					
18	Federal Energy Regulatory Commission:				
19	Annual FERC Billing	2,602,221		2,602,221	
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					
45					
46	TOTAL	11,971,496	149,738	12,121,234	5,259,441

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
		7,009,433					2
							3
							4
					247,000	501,666	5
					210,000	476,372	6
			6,538,038		218,817	6,319,221	7
		-557,157	788,579		231,422	3,181,250	8
							9
							10
		2,359,843					11
					10,133	160,638	12
					15,945	355,263	13
					5,000	653,331	14
							15
							16
							17
							18
		2,602,221					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
							45
		11,414,340	7,326,617		938,317	11,647,741	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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:	Others (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 Co-Funds
15		Testing of Insulators
16		Reliability Analytics
17		Others (Less thank $50K each)
18		
19		Alternative Energy (Advanced Energy Resc.)
20		Centre for Energy Advancement through Technological Innovation
21		Clemson University
22		Georgia Tech Research Corporation
23		General Electric
24		
25	TOTAL ELECTRIC R, D&D PERFORMED EXTERNALLY	
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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 Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
93,398		930.7	93,398		3
					4
					5
					6
93,398			93,398		7
					8
					9
					10
					11
					12
	7,462,611	Various	7,462,611		13
	1,577,749	Various	1,577,749		14
	117,000	107.0	117,000		15
	75,000	506.0	75,000		16
	166,299	Various	166,299		17
					18
	2,121,677	930.8	2,121,677		19
	185,600	930.7	185,600		20
	80,000	930.7	80,000		21
	353,000	930.7	353,000		22
	45,000	930.7	45,000		23
					24
	12,183,936		12,183,936		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	328,525,876		
4	Transmission	13,879,004		
5	Regional Market			
6	Distribution	33,336,404		
7	Customer Accounts	31,371,061		
8	Customer Service and Informational	8,491,989		
9	Sales	8,976,919		
10	Administrative and General	254,085,298		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	678,666,551		
12	Maintenance			
13	Production	237,203,540		
14	Transmission	11,667,468		
15	Regional Market			
16	Distribution	49,429,661		
17	Administrative and General	457,573		
18	TOTAL Maintenance (Total of lines 13 thru 17)	298,758,242		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	565,729,416		
21	Transmission (Enter Total of lines 4 and 14)	25,546,472		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	82,766,065		
24	Customer Accounts (Transcribe from line 7)	31,371,061		
25	Customer Service and Informational (Transcribe from line 8)	8,491,989		
26	Sales (Transcribe from line 9)	8,976,919		
27	Administrative and General (Enter Total of lines 10 and 17)	254,542,871		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	977,424,793	5,141,951	982,566,744
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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	977,424,793	5,141,951	982,566,744
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	245,772,684	21,143,121	266,915,805
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	245,772,684	21,143,121	266,915,805
72	Plant Removal (By Utility Departments)			
73	Electric Plant	29,208,641		29,208,641
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	29,208,641		29,208,641
77	Other Accounts (Specify, provide details in footnote):			
78		4,695,780		4,695,780
79		7,155,564		7,155,564
80		4,629,968		4,629,968
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	16,481,312		16,481,312
96	TOTAL SALARIES AND WAGES	1,268,887,430	26,285,072	1,295,172,502

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	30,288,889	31,640,106	35,881,592	51,171,174
3	Net Sales (Account 447)	274,864	1,427,256	1,499,699	1,502,443
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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					
45					
46	TOTAL	30,563,753	33,067,362	37,381,291	52,673,617

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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			286,563			5,781,558
2	Reactive Supply and Voltage	34,283	MWH	310,656	8,672,119	MWH	7,973,069
3	Regulation and Frequency Response						579,761
4	Energy Imbalance	13,689,154	MWH	2,199,376	13,714,277	MWH	1,765,004
5	Operating Reserve - Spinning						1,486,695
6	Operating Reserve - Supplement						1,486,695
7	Other	947,169	MWH	4,914,172	41,044	MWH	1,696,244
8	Total (Lines 1 thru 7)	14,670,606		7,710,767	22,427,440		20,769,026

Schedule Page: 398 Line No.: 1 Column: g

Schedule Page: 398 Line No:1 Column: g

$1,667,561.33 is based on upon $/MWH and $8,672,119 MWH. The remainder is based upon Load Ratio Share (LRS) calculation. The LRS calculation uses a twelve month rolling average for coincidental peak demand.

Schedule Page: 398 Line No.: 2 Column: g

Schedule Page: 398 Line No: 2 Column; g

$3,303,570.87 is based upon $/MWH and $8,672,119 MWH. The remainder is based upon Load Ratio Share (LRS) calculation. The LRS calculations uses a twelve month rolling average from coincidental peak demand.

Schedule Page: 398 Line No.: 3 Column: g

Schedule Page: 398 Line No: 3 Column; g

The dollars are based upon a Load Ratio Share (LRS) calculation. The LRS calculation uses a twelve month rolling average for coincidental peak demand.

Schedule Page: 398 Line No.: 4 Column: b

Schedule Page: 398 Line No: 4 Column: b

Energy Imbalance is also reported on FERC Form 1 pages 326-327.

Schedule Page: 398 Line No.: 4 Column: d

Schedule Page: 398 Line No: 4 Column: d

Energy Imbalance is also reported on FERC 1 pages 326-327.

Schedule Page: 398 Line No.: 4 Column: e

Schedule Page: 398 Line No: 4 Column: e

Energy Imbalance is also reported on FERC Form 1, pages 326-327.

Schedule Page: 398 Line No.: 4 Column: g

Schedule Page: 398 Line No:4 Column: g

Energy Imbalance is also reported on FERC Form 1, pages 326-327.

Schedule Page: 398 Line No.: 5 Column: g

Schedule Page: 398 Line No:5 Column: g

The dollars are based upon a Load Ratio Share (LRS) calculation. The LRS calculation uses a twelve month rolling aveerage for coincidental peak demand.

Schedule Page: 398 Line No.: 6 Column: g

Schedule Page: 398 Line No: 6 Column: g

The dollars are based upon a Load Ratio Share (LRS) calculation. The LRS calculation uses a twelve month rolling average for coincidental peak demand.

Schedule Page: 398 Line No.: 7 Column: b

Schedule Page: 398 Line No: 7 Column: b

The number of units represent Generator Imbalance purchased from Broad River Energy Center, Cargill-Alliant, LLC, North Carolina Municipal Power Agency 1, Piedmont Municipal Power Agency, Southern Power Company - Rowan Plant, Southern Power Company - Cleveland Plant, and PJM settlements, Inc. The number of units are also reported on FERC Form 1 pages 326-327.

Schedule Page: 398 Line No.: 7 Column: d

Schedule Page: 398 Line No: 7 Column: d

The dollars represents Generator Imbalance purchased from Broad River Energy Center, Cargill-Alliant, LLC, North Carolina Municipal Power Agency 1, Piedmont Municipal Power Agency, Southern Power Plant - Rowan Plant, Southern Power Plant - Cleveland Plant, Also, included in this amount are PJM black start services, PJM balancing operating reserves, and PJM load response.

Schedule Page: 398 Line No.: 7 Column: e

Schedule Page: 398 Line No: 7 Column: e

The number of units represents Generator Imbalance and Sales to PJM Settlements, Inc. The number of units are also reported on FERC Form 1, pages 310-311.

Schedule Page: 398 Line No.: 7 Column: g

Schedule Page: 398 Line No: 7 Column: g

The dollars represents Generator Imbalance and PJM balancing operating reserve.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	24,025	5	8	15,654	4,994	2,196		1,181	
2	February	18,937	3	9	12,275	3,810	2,196		656	
3	March	18,830	15	8	12,759	3,551	2,196		324	
4	Total for Quarter 1				40,688	12,355	6,588		2,161	
5	April	16,061	17	8	10,509	2,921	2,196		435	
6	May	20,328	14	6	13,746	3,975	2,196		411	
7	June	22,683	19	4	15,439	4,588	2,196		460	
8	Total for Quarter 2				39,694	11,484	6,588		1,306	
9	July	22,430	11	17	15,401	4,597	2,196		236	
10	August	22,166	30	17	15,117	4,399	2,182		468	
11	September	21,498	6	17	14,712	4,245	2,196		345	
12	Total for Quarter 3				45,230	13,241	6,574		1,049	
13	October	20,069	5	17	12,592	3,935	2,196		1,346	
14	November	19,572	28	8	12,851	3,816	2,196		709	
15	December	20,069	6	8	13,562	3,900	2,196		411	
16	Total for Quarter 4				39,005	11,651	6,588		2,466	
17	Total Year to Date/Year				164,617	48,731	26,338		6,982	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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									

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)	81,033,245
3	Steam	22,936,073			
4	Nuclear	44,770,657	23	Requirements Sales for Resale (See instruction 4, page 311.)	9,146,762
5	Hydro-Conventional	2,877,050			
6	Hydro-Pumped Storage	2,651,766	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,100,206
7	Other	16,507,637			
8	Less Energy for Pumping	3,180,992	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	86,562,191	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	190,883
10	Purchases	11,131,534	27	Total Energy Losses	5,070,681
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	97,541,777
12	Received	7,750,015			
13	Delivered	7,979,866			
14	Net Exchanges (Line 12 minus line 13)	-229,851			
15	Transmission For Other (Wheeling)				
16	Received	37,757,456			
17	Delivered	37,679,553			
18	Net Transmission for Other (Line 16 minus line 17)	77,903			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	97,541,777			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	9,479,021	264,792	18,935	5	800
30	February	6,758,591	42,259	14,575	3	900
31	March	7,617,290	228,398	14,518	15	800
32	April	6,629,987	229,192	12,230	17	800
33	May	7,934,256	164,880	15,667	14	1800
34	June	8,912,723	266,802	17,632	19	1700
35	July	9,097,407	51,344	17,357	11	1700
36	August	9,303,141	83,071	17,225	30	1700
37	September	8,597,977	276,330	16,658	6	1700
38	October	7,414,718	87,631	15,363	4	1700
39	November	7,573,153	167,557	15,241	28	700
40	December	8,223,513	237,950	15,713	6	700
41	TOTAL	97,541,777	2,100,206			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

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)	2240			2081		
7	Plant Hours Connected to Load	6698			8684		
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	171			209		
12	Net Generation, Exclusive of Plant Use - KWh	8021417000			8486270000		
13	Cost of Plant: Land and Land Rights	21738415			5829127		
14	Structures and Improvements	329617289			177753235		
15	Equipment Costs	1856854797			1566908605		
16	Asset Retirement Costs	242332508			246670731		
17	Total Cost	2450543009			1997161698		
18	Cost per KW of Installed Capacity (line 17/5) Including	983.6798			942.5020		
19	Production Expenses: Oper, Supv, & Engr	3864728			4440801		
20	Fuel	248265105			255047165		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	16818140			15631121		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	-22			-18		
25	Electric Expenses	1401414			2335330		
26	Misc Steam (or Nuclear) Power Expenses	5320866			5236860		
27	Rents	0			0		
28	Allowances	1819			1693		
29	Maintenance Supervision and Engineering	4674208			3839799		
30	Maintenance of Structures	12067660			5164734		
31	Maintenance of Boiler (or reactor) Plant	13785625			12355167		
32	Maintenance of Electric Plant	7305692			6067265		
33	Maintenance of Misc Steam (or Nuclear) Plant	2348327			1650557		
34	Total Production Expenses	315853562			311770474		
35	Expenses per Net KWh	0.0394			0.0367		
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	3018081	70940	0	3239539	32457	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12522	137821	0	12450	137867	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	78.750	91.160	0.000	79.080	92.750	0.000
41	Average Cost of Fuel per Unit Burned	79.110	91.037	0.000	76.440	90.964	0.000
42	Average Cost of Fuel Burned per Million BTU	3.176	15.727	0.000	3.070	15.709	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.031	0.031	0.000	0.030	0.030	0.000
44	Average BTU per KWh Net Generation	9424.000	9424.000	0.000	9527.000	9527.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

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	1344			0		
20	Fuel	210			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	61952			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	408633			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	355			2817		
30	Maintenance of Structures	568503			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	834			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	-4863			0		
34	Total Production Expenses	1036968			2817		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		MCF	Barrels	
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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

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	136			97764		
20	Fuel	3053			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			3587		
26	Misc Steam (or Nuclear) Power Expenses	63896			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	60024			0		
30	Maintenance of Structures	100441			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			12887		
33	Maintenance of Misc Steam (or Nuclear) Plant	79581			0		
34	Total Production Expenses	307131			114238		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		MCF	Barrels	
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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

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			463.90
6	Net Peak Demand on Plant - MW (60 minutes)			2397			456
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			1092			946
12	Net Generation, Exclusive of Plant Use - KWh			19862068000			3614343949
13	Cost of Plant: Land and Land Rights			754812			779551
14	Structures and Improvements			688865400			244337031
15	Equipment Costs			2636227010			603669022
16	Asset Retirement Costs			-218450499			13598241
17	Total Cost			3107396723			862383845
18	Cost per KW of Installed Capacity (line 17/5) Including			1273.2102			1858.9865
19	Production Expenses: Oper, Supv, & Engr			18691906			3260771
20	Fuel			122879315			23264781
21	Coolants and Water (Nuclear Plants Only)			3558243			992516
22	Steam Expenses			19719315			3665861
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			2336717			475843
26	Misc Steam (or Nuclear) Power Expenses			73968218			13835490
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			25865369			4375439
30	Maintenance of Structures			5513117			1116855
31	Maintenance of Boiler (or reactor) Plant			34725291			7774891
32	Maintenance of Electric Plant			21342013			4447096
33	Maintenance of Misc Steam (or Nuclear) Plant			19696761			4477083
34	Total Production Expenses			348296265			67686626
35	Expenses per Net KWh			0.0175			0.0187
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	198316000	0	2810658	189177000	0	2875472
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	43.703	0.000	0.000	41.953	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.619	0.000	0.000	0.638	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	9985.000	0.000	0.000	10073.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

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			738.79		
6	Net Peak Demand on Plant - MW (60 minutes)	718			827		
7	Plant Hours Connected to Load	8218			5491		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	718			0		
10	When Limited by Condenser Water	662			753		
11	Average Number of Employees	45			4		
12	Net Generation, Exclusive of Plant Use - KWh	4962258000			0		
13	Cost of Plant: Land and Land Rights	119364			191853		
14	Structures and Improvements	145096631			12554329		
15	Equipment Costs	511846243			582151257		
16	Asset Retirement Costs	0			0		
17	Total Cost	657062238			594897439		
18	Cost per KW of Installed Capacity (line 17/5) Including	941.5523			805.2321		
19	Production Expenses: Oper, Supv, & Engr	3205154			2366527		
20	Fuel	147446109			77556978		
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	1509945			641098		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1524381			948366		
30	Maintenance of Structures	1094002			647867		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	3024851			1232816		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	157804442			83393652		
35	Expenses per Net KWh	0.0318			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil		Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	Barrels		MCF	Barrels	
38	Quantity (Units) of Fuel Burned	34734762	0	0	21924085	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1025	0	0	1023	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.243	0.000	0.000	3.537	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.243	0.000	0.000	3.537	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.138	0.000	0.000	3.457	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.030	0.000	0.000	0.025	0.000	0.000
44	Average BTU per KWh Net Generation	7177.000	0.000	0.000	7150.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

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
1072	174	98	6
2612	637	1095	7
0	0	0	8
1130	173	96	9
1098	170	84	10
105	45	0	11
819761000	54152000	79514000	12
599905	167823	0	13
152985889	34317919	516719	14
1083736643	78767214	61138160	15
194796019	-1205999	0	16
1432118456	112046957	61654879	17
1247.0554	0	570.8785	18
2509861	477171	452957	19
32090155	2521652	4662395	20
0	0	0	21
5259905	243205	0	22
0	0	0	23
-10	-1	0	24
1640748	112614	476930	25
2806754	762896	0	26
0	0	0	27
107	0	0	28
2128603	329294	-295405	29
2901369	457748	121871	30
3434025	319021	0	31
1258030	574556	782757	32
487487	729936	0	33
54517034	6528092	6201505	34
0.0665	0.1206	0.0780	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Coal	Oil	GAS	Gas	Oil		36
Tons	Barrels		Tons	Barrels	MCF	MCF	Barrels		37
388385	19581	0	0	0	695442	655462	20316	0	38
11334	138081	0	0	0	1025	1025	137867	0	39
78.060	94.630	0.000	0.000	0.000	3.586	4.073	98.700	0.000	40
74.250	94.001	0.000	0.000	0.000	3.586	4.073	97.630	0.000	41
3.275	16.209	0.000	0.000	0.000	3.499	3.974	16.861	0.000	42
0.037	0.037	0.000	0.000	0.000	0.046	0.059	0.059	0.000	43
10878.000	10878.000	0.000	0.000	0.000	13161.000	9928.000	9928.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

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: *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
1395	0	0	6
7178	0	0	7
0	0	0	8
1390	0	0	9
1388	0	0	10
116	0	0	11
5554473000	0	0	12
597577	0	0	13
361141354	0	0	14
2615135578	753881	0	15
204360841	0	0	16
3181235350	753881	0	17
2078.5595	0	0	18
2808785	4129	0	19
175946137	3609	0	20
0	0	0	21
15502867	0	0	22
0	0	0	23
-13	0	0	24
1960610	0	0	25
4096446	47234	0	26
0	0	0	27
581	0	0	28
2565924	0	0	29
4035090	96068	0	30
10981066	0	0	31
3411695	0	0	32
670184	860	0	33
221979372	151900	0	34
0.0400	0.0000	0.0000	35

(d) Coal	(d) Oil	(d) Gas	(e) Coal	(e) Oil	(e)	(f) Gas	(f) Oil	(f)	Line No.
Coal	Oil	Gas	Coal	Oil		Gas	Oil		36
Tons	Barrels	MCF	Tons	Barrels		MCF	Barrels		37
2073829	50067	1353615	0	0	0	0	0	0	38
11970	137617	1027	0	0	0	0	0	0	39
78.180	92.450	4.536	0.000	0.000	0.000	0.000	0.000	0.000	40
77.910	92.337	4.536	0.000	0.000	0.000	0.000	0.000	0.000	41
3.255	15.976	4.417	0.000	0.000	0.000	0.000	0.000	0.000	42
0.031	0.031	0.031	0.000	0.000	0.000	0.000	0.000	0.000	43
9241.000	9241.000	9241.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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: *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			1487			2622			6
0			330			8760			7
0			0			0			8
0			1565			2618			9
0			1193			2554			10
0			12			1160			11
0			82484000			21294245000			12
0			3021923			1504454			13
0			28616966			962557339			14
0			376669839			3381392259			15
0			0			-128228347			16
0			408308728			4217225705			17
0			232.8403			1581.4399			18
0			418317			14620472			19
0			11851993			130099939			20
0			0			4496131			21
0			0			22038074			22
0			0			0			23
0			0			0			24
0			2460630			17978406			25
0			0			91413093			26
0			0			0			27
0			0			0			28
0			804955			29426275			29
0			717231			6758061			30
0			0			40419205			31
0			1764345			27842536			32
0			0			31315068			33
0			18017471			416407260			34
0.0000			0.2184			0.0196			35
Coal	Oil		Gas	Oil		MBTUs	Nuclear	Grams of	36
Tons	Barrels		MCF	Barrels				Uranium	37
0	0	0	514456	107927	0	216183000	0	3418385	38
0	0	0	1025	137882	0	0	0	0	39
0.000	0.000	0.000	4.305	103.460	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	4.305	88.042	0.000	0.000	38.051	0.000	41
0.000	0.000	0.000	4.198	15.203	0.000	0.000	0.602	0.000	42
0.000	0.000	0.000	0.142	0.142	0.000	0.000	0.006	0.000	43
0.000	0.000	0.000	13973.000	13973.000	0.000	0.000	9846.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/Q4

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: *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
769			898			719			6
653			4705			8541			7
0			0			0			8
735			895			716			9
563			825			668			10
9			12			45			11
201194000			2325235000			5173061000			12
5063537			967095			0			13
29782579			3365506			147848826			14
221109359			300040940			509083878			15
0			0			0			16
255955475			304373541			656932704			17
320.2646			311.3796			941.3666			18
289763			434986			1605165			19
13998043			93742084			149786592			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
1395924			1992660			2653568			25
0			0			0			26
0			0			0			27
0			0			0			28
438822			775186			917829			29
350976			456933			3670344			30
0			0			0			31
697332			1499461			2240255			32
0			0			0			33
17170860			98901310			160873753			34
0.0853			0.0425			0.0311			35
Gas	Oil		Gas	Oil		Gas	Oil		36
MCF	Barrels		MCF	Barrels		MCF	Barrels		37
2118673	59928	0	24409683	87596	0	35736694	0	0	38
1026	137370	0	1031	138423	0	1030	0	0	39
3.588	98.090	0.000	3.510	97.040	0.000	4.189	0.000	0.000	40
3.588	105.666	0.000	3.510	91.036	0.000	4.189	0.000	0.000	41
3.497	18.315	0.000	3.405	15.659	0.000	4.066	0.000	0.000	42
0.069	0.069	0.000	0.040	0.040	0.000	0.029	0.000	0.000	43
12522.000	12522.000	0.000	11041.000	11041.000	0.000	7160.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/Q4

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: (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

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 $523,877 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 $10,935,266 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

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: 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: 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 $1,586,516.

Schedule Page: 402.4 Line No.: 20 Column: c

Represents respondent's 87.265% ownership share of Lee Combined Cycle.

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 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

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 87.265% ownership share.

Schedule Page: 402.4 Line No.: 39 Column: c1

Lee Combined Cycle calculated using respondent's 87.265% ownership share.

Schedule Page: 402.4 Line No.: 40 Column: c1

Lee Combined Cycle calculated using respondent's 87.265% ownership share.

Schedule Page: 402.4 Line No.: 41 Column: c1

Lee Combined Cycle calculated using respondent's 87.265% ownership share.

Schedule Page: 402.4 Line No.: 42 Column: c1

Lee Combined Cycle calculated using respondent's 87.265% ownership share.

Schedule Page: 402.4 Line No.: 43 Column: c1

Lee Combined Cycle calculated using respondent's 87.265% ownership share.

Schedule Page: 402.4 Line No.: 44 Column: c1

Lee Combined Cycle calculated using respondent's 87.265% ownership share.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	37.05
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	38
7	Plant Hours Connect to Load	8,491	7,777
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	2	3
12	Net Generation, Exclusive of Plant Use - Kwh	117,680,000	119,297,000
13	Cost of Plant		
14	Land and Land Rights	1,229,866	525,914
15	Structures and Improvements	65,238,752	4,003,189
16	Reservoirs, Dams, and Waterways	105,399,463	7,546,537
17	Equipment Costs	35,538,042	19,109,357
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	207,406,123	31,184,997
21	Cost per KW of Installed Capacity (line 20 / 5)	7,479.4851	841.7003
22	Production Expenses		
23	Operation Supervision and Engineering	361,610	196,051
24	Water for Power	0	0
25	Hydraulic Expenses	-134,567	-1,836
26	Electric Expenses	146,431	138,888
27	Misc Hydraulic Power Generation Expenses	103,188	140,337
28	Rents	0	0
29	Maintenance Supervision and Engineering	32,584	39,216
30	Maintenance of Structures	222	43,219
31	Maintenance of Reservoirs, Dams, and Waterways	115,052	42,844
32	Maintenance of Electric Plant	85,563	80,444
33	Maintenance of Misc Hydraulic Plant	104,441	65,739
34	Total Production Expenses (total 23 thru 33)	814,524	744,902
35	Expenses per net KWh	0.0069	0.0062

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	180	73
7	Plant Hours Connect to Load	3,475	5,944
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	16	7
12	Net Generation, Exclusive of Plant Use - Kwh	312,212,000	175,810,000
13	Cost of Plant		
14	Land and Land Rights	12,463,957	2,707,611
15	Structures and Improvements	16,442,484	6,639,141
16	Reservoirs, Dams, and Waterways	36,637,451	21,518,089
17	Equipment Costs	58,433,432	22,014,955
18	Roads, Railroads, and Bridges	2,240,416	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	126,217,740	52,879,796
21	Cost per KW of Installed Capacity (line 20 / 5)	360.6221	881.3299
22	Production Expenses		
23	Operation Supervision and Engineering	1,994,602	347,065
24	Water for Power	0	0
25	Hydraulic Expenses	-537,071	-183,244
26	Electric Expenses	374,210	161,289
27	Misc Hydraulic Power Generation Expenses	1,190,287	233,004
28	Rents	0	0
29	Maintenance Supervision and Engineering	347,461	78,901
30	Maintenance of Structures	14,409	15,213
31	Maintenance of Reservoirs, Dams, and Waterways	144,794	77,463
32	Maintenance of Electric Plant	290,205	155,675
33	Maintenance of Misc Hydraulic Plant	223,009	173,926
34	Total Production Expenses (total 23 thru 33)	4,041,906	1,059,292
35	Expenses per net KWh	0.0129	0.0060

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	7,203
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	16	45
10	(b) Under the Most Adverse Oper Conditions	14	43
11	Average Number of Employees	0	3
12	Net Generation, Exclusive of Plant Use - Kwh	-73,000	178,151,000
13	Cost of Plant		
14	Land and Land Rights	0	34,920
15	Structures and Improvements	0	3,989,687
16	Reservoirs, Dams, and Waterways	0	12,029,057
17	Equipment Costs	0	16,319,236
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	32,372,900
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	719.3978
22	Production Expenses		
23	Operation Supervision and Engineering	8,868	171,707
24	Water for Power	0	0
25	Hydraulic Expenses	20,976	4,015
26	Electric Expenses	14	212,965
27	Misc Hydraulic Power Generation Expenses	77,672	165,334
28	Rents	0	0
29	Maintenance Supervision and Engineering	272	44,084
30	Maintenance of Structures	26,603	16,111
31	Maintenance of Reservoirs, Dams, and Waterways	3,023	44,113
32	Maintenance of Electric Plant	12,824	130,133
33	Maintenance of Misc Hydraulic Plant	12,098	31,845
34	Total Production Expenses (total 23 thru 33)	162,350	820,307
35	Expenses per net KWh	0.0000	0.0046

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	81	22
7	Plant Hours Connect to Load	1,362	5,374
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	98,064,000	96,019,000
13	Cost of Plant		
14	Land and Land Rights	21,905,557	1,153,815
15	Structures and Improvements	13,536,904	3,070,673
16	Reservoirs, Dams, and Waterways	17,440,014	4,897,153
17	Equipment Costs	94,847,449	4,431,423
18	Roads, Railroads, and Bridges	0	46,024
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	147,729,924	13,599,088
21	Cost per KW of Installed Capacity (line 20 / 5)	937.9678	629.5874
22	Production Expenses		
23	Operation Supervision and Engineering	267,598	216,690
24	Water for Power	0	0
25	Hydraulic Expenses	-311,578	51,055
26	Electric Expenses	1,195,078	7,369
27	Misc Hydraulic Power Generation Expenses	297,374	67,831
28	Rents	0	0
29	Maintenance Supervision and Engineering	50,084	57,812
30	Maintenance of Structures	44,154	19,238
31	Maintenance of Reservoirs, Dams, and Waterways	461,127	136,117
32	Maintenance of Electric Plant	402,370	189,519
33	Maintenance of Misc Hydraulic Plant	247,560	214,554
34	Total Production Expenses (total 23 thru 33)	2,653,767	960,185
35	Expenses per net KWh	0.0271	0.0100

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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. 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	25.77	60.00	5
41	31	65	6
8,415	8,735	5,757	7
			8
44	28	62	9
40	28	58	10
3	1	1	11
107,478,000	162,927,000	207,502,000	12
			13
1,247,589	550,590	800,211	14
4,113,826	2,520,600	3,374,178	15
30,626,357	5,618,091	5,531,690	16
22,944,173	13,188,149	19,476,918	17
0	0	0	18
0	0	0	19
58,931,945	21,877,430	29,182,997	20
1,636.9985	848.9496	486.3833	21
			22
180,247	152,412	281,736	23
0	0	0	24
-73,542	27,155	-13,540	25
138,345	167,501	114,188	26
169,862	119,904	230,314	27
0	0	0	28
41,930	26,406	67,416	29
40,505	93,435	15,665	30
160,201	36,144	44,327	31
428,440	80,633	145,781	32
145,858	31,722	28,199	33
1,231,846	735,312	914,086	34
0.0115	0.0045	0.0044	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
36.72	24.00	45.50	5
53	0	48	6
6,546	0	8,546	7
			8
56	14	47	9
49	11	42	10
3	5	2	11
203,570,000	-92,000	222,145,000	12
			13
373,568	27,613	0	14
4,376,021	471,321	2,137,143	15
15,283,129	2,869,197	1,506,206	16
27,548,025	6,452,720	15,937,629	17
0	0	633,636	18
0	0	0	19
47,580,743	9,820,851	20,214,614	20
1,295.7719	409.2021	444.2772	21
			22
186,026	93,020	121,026	23
0	0	0	24
37,066	1,071	3,745	25
212,584	8,712	145,613	26
181,404	219,593	245,872	27
0	0	0	28
47,093	12,398	38,465	29
12,491	14,804	1,464	30
731,048	32,755	24,779	31
158,425	17,306	77,580	32
243,272	28,144	21,597	33
1,809,409	427,803	680,141	34
0.0089	0.0000	0.0031	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
56.00	18.00	0.00	5
90	17	0	6
8,751	8,726	0	7
			8
90	20	0	9
85	10	0	10
2	2	0	11
336,004,000	83,267,000	0	12
			13
627,443	151,343	0	14
9,060,996	1,507,510	0	15
14,861,723	11,666,336	0	16
29,535,061	11,755,179	0	17
0	0	0	18
0	0	0	19
54,085,223	25,080,368	0	20
965.8076	1,393.3538	0.0000	21
			22
507,327	188,094	0	23
0	0	0	24
52,231	19,768	0	25
199,601	74,643	0	26
264,410	247,297	0	27
0	0	0	28
85,068	13,293	0	29
42,035	1,336	0	30
101,774	110,202	0	31
689,586	139,225	0	32
82,342	92,978	0	33
2,024,374	886,836	0	34
0.0060	0.0107	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
51	10	0	6
6,077	5,973	0	7
			8
51	11	0	9
37	7	0	10
2	0	0	11
270,145,000	48,109,000	0	12
			13
469,013	475,718	0	14
2,173,944	355,878	0	15
13,526,218	4,890,494	0	16
7,226,735	2,587,236	0	17
239,971	72,590	0	18
0	0	0	19
23,635,881	8,381,916	0	20
547.1269	776.1033	0.0000	21
			22
280,409	151,254	0	23
0	0	0	24
41,013	0	0	25
73,256	3,377	0	26
174,581	22,732	0	27
0	0	0	28
151,781	4,101	0	29
7,456	673	0	30
190,175	16,510	0	31
150,384	58,337	0	32
173,511	52,350	0	33
1,242,566	309,334	0	34
0.0046	0.0064	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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

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

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: e

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: f

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.: 10 Column: b

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 Line No.: 10 Column: c

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 Line No.: 10 Column: d

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 Line No.: 10 Column: e

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 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.: 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: 406.1 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: 406.1 Line No.: 9 Column: d

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: 406.1 Line No.: 9 Column: e

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: 406.1 Line No.: 9 Column: f

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: 406.1 Line No.: 10 Column: b

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.: 10 Column: c

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.: 10 Column: d

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.: 10 Column: e

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.: 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

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: d

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: e

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.: 10 Column: b

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: 406.2 Line No.: 10 Column: c

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: 406.2 Line No.: 10 Column: d

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: 406.2 Line No.: 10 Column: e

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: 406.3 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: 406.3 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: 406.3 Line No.: 9 Column: d

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: 406.3 Line No.: 9 Column: e

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: 406.3 Line No.: 10 Column: b

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: 406.3 Line No.: 10 Column: c

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: 406.3 Line No.: 10 Column: d

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: 406.3 Line No.: 10 Column: e

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: 406.3 Line No.: 11 Column: b

Remote control operation.

Schedule Page: 406.3 Line No.: 11 Column: e

Remote control operation.

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)	785
6	Plant Hours Connect to Load While Generating	4,674
7	Net Plant Capability (in megawatts)	780
8	Average Number of Employees	14
9	Generation, Exclusive of Plant Use - Kwh	1,204,730,000
10	Energy Used for Pumping	1,342,401,000
11	Net Output for Load (line 9 - line 10) - Kwh	-137,671,000
12	Cost of Plant	
13	Land and Land Rights	5,273,013
14	Structures and Improvements	28,418,569
15	Reservoirs, Dams, and Waterways	52,373,977
16	Water Wheels, Turbines, and Generators	71,154,555
17	Accessory Electric Equipment	13,791,024
18	Miscellaneous Powerplant Equipment	3,900,448
19	Roads, Railroads, and Bridges	415,508
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	175,327,094
22	Cost per KW of installed cap (line 21 / 4)	246.9396
23	Production Expenses	
24	Operation Supervision and Engineering	836,416
25	Water for Power	
26	Pumped Storage Expenses	43,043
27	Electric Expenses	951,004
28	Misc Pumped Storage Power generation Expenses	1,712,626
29	Rents	
30	Maintenance Supervision and Engineering	621,194
31	Maintenance of Structures	166,821
32	Maintenance of Reservoirs, Dams, and Waterways	238,291
33	Maintenance of Electric Plant	1,078,869
34	Maintenance of Misc Pumped Storage Plant	447,276
35	Production Exp Before Pumping Exp (24 thru 34)	6,095,540
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	6,095,540
38	Expenses per KWh (line 37 / 9)	0.0051

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
1,402			5
2,134			6
1,360			7
34			8
1,447,036,000			9
1,838,590,900			10
-391,554,900			11
			12
1,145,342			13
228,124,721			14
455,304,760			15
238,780,281			16
51,305,557			17
28,870,301			18
17,869,699			19
			20
1,021,400,661			21
959.0617			22
			23
1,474,595			24
			25
-800			26
1,031,093			27
2,563,382			28
			29
932,625			30
145,078			31
80,500			32
1,385,364			33
1,425,698			34
9,037,535			35
			36
9,037,535			37
0.0062			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	37,230,000	11,653,222
3	Bryson - Project 2601	1925	1.00	1.0	4,632,000	6,547,000
4	Cedar Cliff - Project 2698	1952	6.40	7.0	27,615,000	7,422,249
5	Franklin - Project 2603	1925	1.00	1.0	3,726,000	8,018,201
6	Gaston Shoals - Project 2332	1908	5.30	4.4	14,686,000	20,532,919
7	Missions - Project 2619	1924	1.80	2.0	5,389,000	8,077,584
8	Queen's Creek - Project 2694	1949	1.40	2.0	4,623,000	1,318,518
9	Tuckasegee - Project 2686	1950	3.00	3.0	7,077,000	3,899,196
10	Tuxedo	1920	5.00	8.0	33,861,000	10,907,061
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						
45						
46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
1,294,802	118,450		145,141			2
6,547,000	80,072		22,291			3
1,159,726	122,728		175,624			4
8,018,201	42,812		15,378			5
3,874,136	423,114		153,477			6
4,487,547	58,596		113,892			7
941,799	36,459		73,725			8
1,299,732	101,756		70,972			9
2,181,412	175,174		145,957			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
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	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	25.69		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	8,242.24	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 (Pole miles) 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	26.16		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	8,242.24	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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					1,393.37		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	54.89		5
34	100 KV Lines		100.00	100.00	Tower	739.71		246
35	100 KV Lines		100.00	100.00	Pole	188.19		249
36					TOTAL	8,242.24	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	100 KV Lines		100.00	100.00	Underground	5.47		7
2	100 kV Lines		100.00		Tower & Pole	2,631.01		404
3	TOTAL 100 - 138 KV LINES					3,625.77		912
4								
5	66 KV Lines		66.00	66.00	Pole	99.14		25
6	66 KV Lines		66.00	66.00	Tower & Pole	6.45		3
7								
8	TOTAL 66 KV LINES					105.59		28
9								
10	44 KV Lines		44.00	44.00	Tower	0.14		8
11	44 KV Lines		44.00	44.00	Pole	1,352.76		1,038
12	44 KV Lines		44.00	44.00	Underground	7.21		15
13	44 kV Lines		44.00	44.00	Tower & Pole	981.65		193
14	TOTAL 44 KV LINES					2,341.76		1,254
15								
16	33 KV Lines		33.00	33.00	Tower & Pole	16.02		4
17	24 KV Lines		24.00	24.00	Tower & Pole	53.95		35
18	24 KV Lines		24.00	24.00	Underground	0.95		2
19	4 to 12 KV Lines		12.00	12.00	Tower & Pole	21.88		52
20	4 to 12 KV Lines		12.00	12.00	Underground	0.24		2
21								
22	TOTAL 4-33 KV LINES					93.04		95
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,242.24	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
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	107,074,231	127,730,367					15
	20,656,136	107,074,231	127,730,367					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
	178,908,815	1,914,639,475	2,093,548,290	938,130	25,082,416		26,020,546	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
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
	178,908,815	1,914,639,475	2,093,548,290	938,130	25,082,416		26,020,546	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
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	288,065,257	329,458,966					15
	41,393,709	288,065,257	329,458,966					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	113,362,577	117,099,116					29
	3,736,539	113,362,577	117,099,116					30
								31
477								32
								33
								34
								35
	178,908,815	1,914,639,475	2,093,548,290	938,130	25,082,416		26,020,546	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
	77,073,434	934,870,980	1,011,944,414					2
	77,073,434	934,870,980	1,011,944,414					3
								4
								5
								6
	5,793,848	41,916,828	47,710,676					7
	5,793,848	41,916,828	47,710,676					8
								9
								10
								11
								12
	29,586,265	421,622,566	451,208,831					13
	29,586,265	421,622,566	451,208,831					14
								15
								16
								17
								18
								19
								20
	668,884	7,727,036	8,395,920					21
	668,884	7,727,036	8,395,920					22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
				938,130	25,082,416		26,020,546	35
	178,908,815	1,914,639,475	2,093,548,290	938,130	25,082,416		26,020,546	36

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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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 From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Overhead New Lines						
2	APPLE STA 2	HICKORY TIE	0.30	Poles	10.00	1	1
3	CLEARWATER PAPER II		1.68	Poles	10.70	1	1
4	MARSHALL STM STA	TERRELL 44KV LN	0.07	Poles	42.90	1	1
5	SOCK HILL RET TAP		0.74	Towers & poles	9.50	1	1
6							
7							
8							
9	Underground New Lines						
10	MARSHALL STM STA	TERRELL 44KV LN	0.14	Underground		1	1
11							
12							
13							
14							
15	Major Rebuild						
16	FAIRVIEW TIE	ANDALE	4.80	Towers & Poles	7.90	2	2
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		7.73		81.00	7	7

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
									1
556	ACSR		100			543,916	804	544,720	2
556	ACSR		100		1,187,919	917,125		2,105,044	3
477	ACSS/TW		44		2,158,565	249,427	30,264	2,438,256	4
477	ACSS/TW		100		966,778	281,846	203,492	1,452,116	5
									6
									7
									8
									9
1000	Aluminm		44		2,158,565	249,427	30,264	2,438,256	10
									11
									12
									13
									14
									15
477	ACSS/TW		100		3,588,250	3,274,675	317,412	7,180,337	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
					10,060,077	5,516,416	582,236	16,158,729	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	ACREROCK TIE DALLAS NC	TRANS	24.00	0.20	
12	ADVANCE RET ADVANCE NC	DIST	100.00	13.00	
13	ADVANCE RET ADVANCE NC	DIST	100.00	13.00	
14	ALBEMARLE CITY DEL 2 ALBEMARLE NC	DIST	100.00	24.00	
15	ALBEMARLE CITY DEL 2 ALBEMARLE NC	DIST	100.00	24.00	13.00
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	ALBEMARLE SW STA ALBEMARLE NC	DIST	100.00	13.00	6.90
23	ALLEN STEAM PL BELMONT NC	TRANS	230.00	100.00	13.00
24	ALLEN STEAM PL BELMONT NC	TRANS	100.00	24.00	
25	ALLEN STEAM PL BELMONT NC	TRANS	100.00	24.00	
26	ALLEN STEAM PL BELMONT NC	TRANS	230.00	100.00	44.00
27	ALLEN STEAM PL BELMONT NC	TRANS	230.00	13.00	
28	ALLEN STEAM PL BELMONT NC	TRANS	230.00	13.00	
29	ALLEN STEAM PL BELMONT NC	TRANS	100.00	13.00	
30	ALLEN STEAM PL BELMONT NC	TRANS	100.00	15.00	15.00
31	ALLEN STEAM PL BELMONT NC	TRANS	230.00	13.00	
32	ANDERSON TIE STARR SC	TRANS	230.00	100.00	44.00
33	ANDERSON TIE STARR SC	TRANS	230.00	100.00	44.00
34	ANDERSON TIE STARR SC	TRANS	230.00	44.00	
35	ANDERSON TIE STARR SC	TRANS	230.00	100.00	44.00
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	2.40	0.60
39	ANDERSON TIE STARR SC	TRANS	44.00		
40	ANDERSON TIE STARR SC	TRANS	44.00	0.40	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	25.00
2	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	25.00
3	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	25.00
4	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	25.00
5	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	25.00
6	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	25.00
7	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	25.00
8	ANTIOCH TIE WILKESBORO NC	TRANS	13.00	0.40	
9	ANTIOCH TIE WILKESBORO NC	TRANS	13.00	0.40	
10	APALACHE RET GREER SC	DIST	44.00	13.00	
11	APALACHE RET GREER SC	DIST	44.00	13.00	
12	ARROWOOD RET CHARLOTTE NC	DIST	100.00	24.00	
13	ARROWOOD RET CHARLOTTE NC	DIST	100.00	24.00	
14	ARROWOOD RET CHARLOTTE NC	DIST	100.00	24.00	
15	ASHCRAFT AVE RET MONROE NC	DIST	100.00	24.00	
16	ASHE ST SW STA DURHAM NC	TRANS	100.00	13.00	
17	ASHE ST SW STA DURHAM NC	TRANS	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	ASHEVILLE HWY RET HENDERSONVILLE NC	DIST	100.00	13.00	
21	AUGUSTA RD RET GREENVILLE SC	DIST	100.00	13.00	
22	AUGUSTA RD RET GREENVILLE SC	DIST	100.00	13.00	
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	AVONDALE RET AVONDALE NC	DIST	44.00	6.90	2.40
30	BAD CREEK HYDRO BAD CREEK SC	TRANS	500.00	24.00	24.00
31	BAD CREEK HYDRO BAD CREEK SC	TRANS	525.00	19.00	
32	BAD CREEK HYDRO BAD CREEK SC	TRANS	525.00	19.00	
33	BAD CREEK HYDRO BAD CREEK SC	TRANS	525.00	19.00	
34	BAD CREEK HYDRO BAD CREEK SC	TRANS	100.00	4.10	
35	BAINBRIDGE RET GREENVILLE SC	DIST	100.00	13.00	
36	BAINBRIDGE RET GREENVILLE SC	DIST	100.00	13.00	
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	2.40	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	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	BALL PARK RET KANNAPOLIS NC	DIST	44.00	6.90	2.40
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	6.90
8	BALSAM RET HENDERSONVILLE NC	DIST	44.00	13.00	
9	BANCROFT RET CHARLOTTE NC	DIST	100.00	13.00	
10	BANCROFT RET CHARLOTTE NC	DIST	100.00	13.00	
11	BANKS ST RET FORT MILL SC	DIST	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	BANNERTOWN TIE MT AIRY NC	TRANS	100.00	13.00	
15	BAPTIST HOSP T&D WINSTON-SALEM NC	DIST	100.00	13.00	
16	BAPTIST HOSP T&D WINSTON-SALEM NC	DIST	100.00	13.00	
17	BARBEE CHAPEL RD RET DURHAM NC	DIST	100.00	24.00	
18	BARRIER RD RET RIMER NC	DIST	100.00	13.00	
19	BEATTIES FORD RET CHARLOTTE NC	DIST	100.00	24.00	
20	BEATTIES FORD RET CHARLOTTE NC	DIST	100.00	13.00	
21	BEAVER DAM RET MARSHVILLE NC	DIST	100.00	24.00	
22	BEAVER DAM RET MARSHVILLE NC	DIST	100.00	24.00	
23	BEAVER DAM RET MARSHVILLE NC	DIST	100.00	24.00	
24	BECKERDITE SVC WINSTON-SALEM NC	TRANS	16.00		
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 SVC WINSTON-SALEM NC	TRANS	100.00	24.00	
29	BECKERDITE TIE WINSTON-SALEM NC	TRANS	230.00	100.00	44.00
30	BECKERDITE TIE WINSTON-SALEM NC	TRANS	230.00	100.00	13.00
31	BECKERDITE TIE WINSTON-SALEM NC	TRANS	230.00	100.00	13.00
32	BECKERDITE TIE WINSTON-SALEM NC	TRANS	230.00	100.00	44.00
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	100.00	13.00	6.90
37	BECKERDITE TIE WINSTON-SALEM NC	TRANS	44.00	0.40	
38	BECKERDITE TIE WINSTON-SALEM NC	TRANS	44.00	0.40	
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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	BEECH ST RET HENDERSONVILLE NC	DIST	44.00	2.40	
2	BEECH ST RET HENDERSONVILLE NC	DIST	44.00	2.40	
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	230.00	13.00	
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	6.90	0.60	
15	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	13.00	6.90	6.90
16	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	230.00	6.90	6.90
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 1 BELEWS CREEK NC	TRANS	6.90	0.60	
23	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	230.00	13.00	
24	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	230.00	24.00	
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	6.90	0.60	
35	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	13.00	6.90	6.90
36	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	230.00	6.90	6.90
37	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
38	BELEWS CREEK SW STA BELEWS CREEK NC	TRANS	6.90	0.40	
39	BELEWS CREEK SW STA BELEWS CREEK NC	TRANS	230.00	18.00	
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
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	BELLHAVEN RET CHARLOTTE NC	DIST	100.00	13.00	
2	BELMONT TIE BELMONT NC	TRANS	100.00	44.00	
3	BELMONT TIE BELMONT NC	TRANS	100.00	44.00	
4	BELMONT TIE BELMONT NC	TRANS	44.00	13.00	
5	BELMONT TIE BELMONT NC	TRANS	44.00	13.00	
6	BELMONT TIE BELMONT NC	TRANS	24.00	0.20	
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	44.00	6.90	2.40
11	BELTON RET BELTON SC	DIST	24.00	2.40	
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	24.00	2.40	0.60
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 RET BELTON SC	DIST	44.00	6.90	2.40
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	100.00	44.00	
25	BELTON TIE BELTON SC	TRANS	24.00	0.20	
26	BEREA RD RET GREENVILLE SC	DIST	100.00	13.00	
27	BEREA RD RET GREENVILLE SC	DIST	100.00	13.00	
28	BERRY SHOALS RET DUNCAN SC	DIST	44.00	13.00	
29	BERRY SHOALS RET DUNCAN SC	DIST	44.00	13.00	
30	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	2.40	
31	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	2.40	
32	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	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	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	6.90	2.40
36	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	6.90	2.40
37	BESSEMER CITY RET BESSEMER CITY NC	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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
2	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
3	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
4	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
5	BETHLEHEM SS HICKORY NC	DIST	44.00	13.00	
6	BETHLEHEM SS HICKORY NC	DIST	44.00	13.00	
7	BETHWARE RET KINGS MOUNTAIN NC	DIST	100.00	13.00	
8	BIG WILLOW RET HENDERSONVILLE NC	DIST	44.00	13.00	
9	BINGHAM RET HILLSBOROUGH NC	DIST	100.00	13.00	
10	BINGHAM RET HILLSBOROUGH NC	DIST	100.00	13.00	
11	BLACK CREEK RET CHESTER SC	DIST	100.00	13.00	
12	BLACKSBURG RET BLACKSBURG SC	DIST	44.00	6.90	
13	BLACKSBURG RET BLACKSBURG SC	DIST	44.00	6.90	
14	BLACKSBURG RET BLACKSBURG SC	DIST	44.00	6.90	
15	BLACKSBURG RET BLACKSBURG SC	DIST	44.00	6.90	
16	BLACKSBURG RET BLACKSBURG SC	DIST	44.00	13.00	
17	BLACKSBURG TIE BLACKSBURG SC	TRANS	100.00	44.00	
18	BLACKSBURG TIE BLACKSBURG SC	TRANS	100.00	44.00	
19	BLACKSBURG TIE BLACKSBURG SC	TRANS	24.00	0.20	
20	BLAKLEY RET LAURENS SC	DIST	44.00	13.00	
21	BLANTON RET SHELBY NC	DIST	44.00	13.00	
22	BLANTON RET SHELBY NC	DIST	44.00	13.00	
23	BLANTYRE RET HORSE SHOE NC	DIST	100.00	13.00	
24	BLUE RIDGE E C DEL 11 EASLEY SC	DIST	100.00	13.00	
25	BLUE RIDGE E C DEL 12 WESTMINSTER SC	DIST	100.00	6.90	
26	BLUE RIDGE E C DEL 12 WESTMINSTER SC	DIST	100.00	6.90	
27	BLUE RIDGE E C DEL 12 WESTMINSTER SC	DIST	100.00	6.90	
28	BLUE RIDGE E C DEL 12 WESTMINSTER SC	DIST	100.00	6.90	
29	BLUE RIDGE E C DEL 14 PICKENS SC	DIST	100.00	6.90	2.40
30	BLUE RIDGE E C DEL 14 PICKENS SC	DIST	100.00	6.90	2.40
31	BLUE RIDGE E C DEL 14 PICKENS SC	DIST	100.00	6.90	2.40
32	BLUE RIDGE E C DEL 14 PICKENS SC	DIST	100.00	6.90	2.40
33	BOB JONES UNIV DIST GREENVILLE SC	DIST	13.00	2.40	
34	BOB JONES UNIV DIST GREENVILLE SC	DIST	13.00	2.40	
35	BOB JONES UNIV DIST GREENVILLE SC	DIST	13.00	2.40	
36	BOB JONES UNIV DIST GREENVILLE SC	DIST	13.00	4.10	
37	BOILING SPRINGS RET BOILING SPRINGS SC	DIST	100.00	13.00	
38	BOILING SPRINGS RET BOILING SPRINGS SC	DIST	100.00	13.00	
39	BOND PARK RET SPARTANBURG SC	DIST	44.00	13.00	
40	BOND PARK RET SPARTANBURG SC	DIST	44.00	24.00	13.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	BOND PARK RET SPARTANBURG SC	DIST	44.00	13.00	4.10
2	BOUNTY LAND SS SENECA SC	DIST	44.00	6.90	2.40
3	BOUNTY LAND SS SENECA SC	DIST	44.00	13.00	6.90
4	BOUNTY LAND SS SENECA SC	DIST	44.00	24.00	13.00
5	BOUNTY LAND SS SENECA SC	DIST	44.00	6.90	2.40
6	BOUNTY LAND SS SENECA SC	DIST	44.00	13.00	
7	BRANCH RD RET WALHALLA SC	DIST	44.00	13.00	
8	BRANCH RD RET WALHALLA SC	DIST	44.00	6.90	2.40
9	BRANCH RD RET WALHALLA SC	DIST	44.00	6.90	2.40
10	BRANCH RD RET WALHALLA SC	DIST	44.00	6.90	2.40
11	BRANTLEY RD RET KANNAPOLIS NC	DIST	100.00	13.00	
12	BRANTLEY RD RET KANNAPOLIS NC	DIST	100.00	13.00	
13	BRASSFIELD RET DURHAM NC	DIST	230.00	24.00	
14	BRASSFIELD RET DURHAM NC	DIST	230.00	24.00	
15	BRASSFIELD RET DURHAM NC	DIST	230.00	24.00	
16	BRAWLEY SCHOOL RET MOORESVILLE NC	DIST	100.00	13.00	
17	BRAWLEY SCHOOL RET MOORESVILLE NC	DIST	100.00	13.00	
18	BRAWLEY SCHOOL RET MOORESVILLE NC	DIST	100.00	24.00	
19	BRAWLEY SCHOOL RET MOORESVILLE NC	DIST	100.00	24.00	
20	BRENTWOOD RET SIMPSONVILLE SC	DIST	100.00	13.00	
21	BRENTWOOD RET SIMPSONVILLE SC	DIST	100.00	13.00	
22	BREVARD RET BREVARD NC	DIST	44.00	2.40	
23	BREVARD RET BREVARD NC	DIST	44.00	2.40	
24	BREVARD RET BREVARD NC	DIST	44.00	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	BREVARD RET BREVARD NC	DIST	44.00	6.90	2.40
32	BREVARD RET BREVARD NC	DIST	44.00	6.90	2.40
33	BRIAR CREEK RET CHARLOTTE NC	DIST	100.00	13.00	
34	BRIAR CREEK RET CHARLOTTE NC	DIST	100.00	13.00	
35	BRIDGEPORT RET MORGANTON NC	DIST	44.00	13.00	
36	BRIDGEPORT RET MORGANTON NC	DIST	44.00	13.00	
37	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	100.00	6.90	
38	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	100.00	6.90	
39	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	100.00	44.00	
40	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	6.90	0.60	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	6.90	0.60	
2	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	6.90	0.60	
3	BROAD ST RET WINSTON-SALEM NC	DIST	100.00	13.00	6.90
4	BROAD ST RET WINSTON-SALEM NC	DIST	100.00	13.00	6.90
5	BROAD ST RET WINSTON-SALEM NC	DIST	100.00	13.00	6.90
6	BROAD ST RET WINSTON-SALEM NC	DIST	100.00	13.00	6.90
7	BROAD ST RET WINSTON-SALEM NC	DIST	100.00	13.00	6.90
8	BROAD ST RET WINSTON-SALEM NC	DIST	100.00	13.00	6.90
9	BROAD ST RET WINSTON-SALEM NC	DIST	100.00	13.00	6.90
10	BROAD ST RET WINSTON-SALEM NC	DIST	100.00	2.40	
11	BROAD ST RET WINSTON-SALEM NC	DIST	100.00	2.40	
12	BROAD ST RET WINSTON-SALEM NC	DIST	100.00	2.40	
13	BROOK ST RET NORTH WILKESBORO NC	DIST	100.00	13.00	
14	BROOK ST RET NORTH WILKESBORO NC	DIST	100.00	13.00	
15	BROOKWOOD RET WINSTON-SALEM NC	DIST	100.00	13.00	
16	BROOKWOOD RET WINSTON-SALEM NC	DIST	100.00	13.00	
17	BROUGHTON RET MORGANTON NC	DIST	44.00	13.00	6.90
18	BROUGHTON RET MORGANTON NC	DIST	44.00	13.00	6.90
19	BROUGHTON RET MORGANTON NC	DIST	44.00	13.00	6.90
20	BROUGHTON RET MORGANTON NC	DIST	44.00	6.90	2.40
21	BROUGHTON RET MORGANTON NC	DIST	44.00	6.90	2.40
22	BROUGHTON RET MORGANTON NC	DIST	44.00	6.90	2.40
23	BROUGHTON RET MORGANTON NC	DIST	44.00	13.00	6.90
24	BROWNS FORD RET NORTH WILKESBORO NC	DIST	100.00	13.00	
25	BROWNS FORD RET NORTH WILKESBORO NC	DIST	100.00	13.00	
26	BRUSHY CREEK RET GREENVILLE SC	DIST	100.00	13.00	
27	BRUSHY CREEK RET GREENVILLE SC	DIST	100.00	13.00	
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	100.00	13.00	
32	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
33	BUCK STEAM STA YARD SPENCER NC	TRANS	100.00	13.00	
34	BUCK STEAM STA YARD SPENCER NC	TRANS	100.00	13.00	
35	BUCK STEAM STA YARD SPENCER NC	TRANS	24.00	4.10	
36	BUCK STEAM STA YARD SPENCER NC	TRANS	24.00	0.60	
37	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	4.10	
38	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
39	BUCK STEAM STA YARD SPENCER NC	TRANS	24.00	4.10	
40	BUCK STEAM STA YARD SPENCER NC	TRANS	24.00	0.60	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	4.10	
2	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
3	BUCK STEAM STA YARD SPENCER NC	TRANS	100.00	13.00	13.00
4	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
5	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
6	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
7	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
8	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
9	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
10	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
11	BUCK STEAM STA YARD SPENCER NC	TRANS	44.00		
12	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	4.10	
13	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	4.10	
14	BUCK STEAM STA YARD SPENCER NC	TRANS	4.10		
15	BUCK STEAM STA YARD SPENCER NC	TRANS			
16	BUCK STEAM STA YARD SPENCER NC	TRANS	4.10		
17	BUCK STEAM STA YARD SPENCER NC	TRANS	4.10		
18	BUCK TIE SPENCER NC	TRANS	230.00	100.00	44.00
19	BUCK TIE SPENCER NC	TRANS	230.00	100.00	13.00
20	BUCK TIE SPENCER NC	TRANS	100.00	13.80	
21	BUCK TIE SPENCER NC	TRANS	13.00	0.40	
22	BUCK TIE SPENCER NC	TRANS	13.00	0.40	
23	BUCKEYE RET CHARLOTTE NC	DIST	100.00	24.00	
24	BUCKEYE RET CHARLOTTE NC	DIST	100.00	24.00	
25	BURLINGTON MN BURLINGTON NC	DIST	100.00	24.00	
26	BURLINGTON MN BURLINGTON NC	DIST	100.00	24.00	
27	BURLINGTON MN BURLINGTON NC	DIST	24.00	2.40	
28	BURLINGTON MN BURLINGTON NC	DIST	24.00	2.40	
29	BURLINGTON MN BURLINGTON NC	DIST	24.00	2.40	
30	BURLINGTON MN BURLINGTON NC	DIST	24.00	2.40	
31	BUSH RIVER TIE NEWBERRY SC	TRANS	230.00	100.00	44.00
32	BUSH RIVER TIE NEWBERRY SC	TRANS	100.00	100.00	13.00
33	BUSH RIVER TIE NEWBERRY SC	TRANS	100.00	100.00	
34	BUSH RIVER TIE NEWBERRY SC	TRANS	100.00	100.00	4.10
35	BUSH RIVER TIE NEWBERRY SC	TRANS	44.00		
36	BUSH RIVER TIE NEWBERRY SC	TRANS	100.00	13.00	6.90
37	BUSH RIVER TIE NEWBERRY SC	TRANS	44.00	2.40	
38	BUSH RIVER TIE NEWBERRY SC	TRANS	44.00	2.40	
39	BUSH RIVER TIE NEWBERRY SC	TRANS	44.00	2.40	
40	BUSH RIVER TIE NEWBERRY SC	TRANS	24.00	0.40	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	BUTNER RET DURHAM NC	DIST	100.00	24.00	
2	BUTNER RET DURHAM NC	DIST	100.00	24.00	
3	BUTNER RET DURHAM NC	DIST	100.00	24.00	
4	BUXTON ST RET WINSTON-SALEM NC	DIST	100.00	13.00	
5	BUXTON ST RET WINSTON-SALEM NC	DIST	100.00	13.00	
6	BUXTON ST RET WINSTON-SALEM NC	DIST	100.00	13.00	
7	BUXTON ST RET WINSTON-SALEM NC	DIST	100.00	24.00	
8	BUXTON ST RET WINSTON-SALEM NC	DIST	100.00	24.00	
9	BUXTON ST RET WINSTON-SALEM NC	DIST	24.00	2.40	
10	BUXTON ST RET WINSTON-SALEM NC	DIST	24.00	2.40	
11	BUXTON ST RET WINSTON-SALEM NC	DIST	24.00	2.40	
12	BUXTON ST RET WINSTON-SALEM NC	DIST	24.00	6.90	2.40
13	BUZZARD ROOST COMB TURBINE CHAPPELLS SC	TRANS	100.00	13.00	13.00
14	BUZZARD ROOST COMB TURBINE CHAPPELLS SC	TRANS	100.00	13.00	
15	BYRUM CREEK RET ANDERSON SC	DIST	100.00	13.00	
16	CAIRO RET NORTH WILKESBORO NC	DIST	100.00	13.00	
17	CAMERON AVE SS CHAPEL HILL NC	TRANS	100.00	13.00	
18	CAMERON AVE SS CHAPEL HILL NC	TRANS	100.00	13.00	
19	CAMP CREEK RD RET WHITTIER NC	DIST	69.00	13.00	
20	CAMP CREEK RD RET WHITTIER NC	DIST	69.00	13.00	
21	CAMP CROFT RET SPARTANBURG SC	DIST	100.00	13.00	
22	CAMP CROFT RET SPARTANBURG SC	DIST	100.00	13.00	
23	CAMPOBELLO TIE CAMPOBELLO SC	TRANS	100.00	44.00	
24	CAMPOBELLO TIE CAMPOBELLO SC	TRANS	100.00	44.00	
25	CAMPOBELLO TIE CAMPOBELLO SC	TRANS	100.00	44.00	
26	CAMPOBELLO TIE CAMPOBELLO SC	TRANS	44.00	13.00	
27	CAMPOBELLO TIE CAMPOBELLO SC	TRANS	24.00	0.20	
28	CAMPTON RET INMAN SC	DIST	100.00	13.00	
29	CAMPTON RET INMAN SC	DIST	100.00	13.00	
30	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	
31	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	
32	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	
33	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	44.00
34	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	24.00
35	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	24.00
36	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	24.00
37	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	
38	CANOE CREEK RET MORGANTON NC	DIST	44.00	13.00	6.90
39	CANOE CREEK RET MORGANTON NC	DIST	44.00	6.90	
40	CANOE CREEK RET MORGANTON NC	DIST	44.00	6.90	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	CANOE CREEK RET MORGANTON NC	DIST	44.00	6.90	
2	CANOE CREEK RET MORGANTON NC	DIST	44.00	13.00	6.90
3	CANOE CREEK RET MORGANTON NC	DIST	44.00	13.00	6.90
4	CANOE CREEK RET MORGANTON NC	DIST	44.00	13.00	6.90
5	CARMEL RD RET CHARLOTTE NC	DIST	100.00	13.00	
6	CARMEL RD RET CHARLOTTE NC	DIST	100.00	13.00	
7	CARMEL RD RET CHARLOTTE NC	DIST	100.00	13.00	
8	CARSON RET MARION NC	DIST	44.00	13.00	
9	CARSON RET MARION NC	DIST	44.00	13.00	
10	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
11	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
12	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
13	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
14	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
15	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
16	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
17	CASHIERS RET CASHIERS NC	DIST	69.00	13.00	
18	CASHIERS RET CASHIERS NC	DIST	69.00	13.00	
19	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	230.00	24.00	
20	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	4.10	
21	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	4.10	
22	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	24.00	13.00	
23	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	230.00	24.00	
24	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
25	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
26	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
27	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	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	6.90	0.60	
31	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
32	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	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	24.00	6.90	6.90
35	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	24.00	6.90	6.90
36	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	24.00	6.90	6.90
37	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	24.00	6.90	6.90
38	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
39	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
40	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
2	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
3	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
4	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
5	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
6	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
7	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	13.00	0.60	
8	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	13.00	0.60	
9	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	13.00	0.60	
10	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
11	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
12	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	4.10	
13	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
14	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
15	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90		
16	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.40	
17	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
18	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	13.00	0.60	
19	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	230.00	24.00	
20	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.40	
21	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.40	
22	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	4.10	
23	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	4.10	
24	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	24.00	13.00	
25	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	230.00	24.00	
26	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
27	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
28	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	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	4.10	0.60	
32	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
33	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	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	24.00	6.90	6.90
37	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	24.00	6.90	6.90
38	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	24.00	6.90	6.90
39	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	24.00	6.90	6.90
40	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
2	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
3	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
4	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
5	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
6	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
7	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
8	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	13.00	0.60	
9	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	13.00	0.60	
10	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	13.00	0.60	
11	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
12	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
13	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	4.10	
14	CATAWBA RET CATAWBA NC	DIST	44.00	13.00	
15	CATAWBA RET CATAWBA NC	DIST	44.00	13.00	
16	CATFISH RET HICKORY NC	DIST	44.00	13.00	
17	CATFISH RET HICKORY NC	DIST	44.00	13.00	
18	CATHEY RD RET ANDERSON SC	DIST	100.00	13.00	
19	CEDAR CREEK HYDRO YARD GREAT FALLS SC	TRANS	100.00	6.90	
20	CEDAR CREEK HYDRO YARD GREAT FALLS SC	TRANS	100.00	6.90	
21	CEDAR CREEK HYDRO YARD GREAT FALLS SC	TRANS	100.00	6.90	
22	CEDAR CREEK HYDRO YARD GREAT FALLS SC	TRANS	0.60	0.20	
23	CENTRAL TIE CENTRAL SC	TRANS	230.00	100.00	44.00
24	CENTRAL TIE CENTRAL SC	TRANS	230.00	100.00	44.00
25	CENTRAL TIE CENTRAL SC	TRANS	230.00	100.00	44.00
26	CENTRAL TIE CENTRAL SC	TRANS	230.00	100.00	44.00
27	CENTRAL TIE CENTRAL SC	TRANS	44.00		
28	CENTRAL TIE CENTRAL SC	TRANS	44.00		
29	CENTRAL TIE CENTRAL SC	TRANS	44.00	6.90	2.40
30	CENTRAL TIE CENTRAL SC	TRANS	44.00	6.90	2.40
31	CENTRAL TIE CENTRAL SC	TRANS	44.00	6.90	2.40
32	CHAMBERS RET MORGANTON NC	DIST	44.00	6.90	2.40
33	CHAMBERS RET MORGANTON NC	DIST	44.00	6.90	
34	CHAMBERS RET MORGANTON NC	DIST	44.00	6.90	
35	CHAMBERS RET MORGANTON NC	DIST	44.00	6.90	
36	CHEROKEE RESERVATION RET CHEROKEE NC	DIST	66.00	13.00	
37	CHEROKEE RESERVATION RET CHEROKEE NC	DIST	66.00	13.00	
38	CHEROKEE RESERVATION RET CHEROKEE NC	DIST	66.00	13.00	
39	CHERRYVILLE MAIN CHERRYVILLE NC	DIST	44.00	13.00	
40	CHERRYVILLE MAIN CHERRYVILLE 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	CHERRYVILLE RET CHERRYVILLE NC	DIST	44.00	13.00	
2	CHERRYVILLE TIE CHERRYVILLE NC	TRANS	100.00	44.00	
3	CHERRYVILLE TIE CHERRYVILLE NC	TRANS	100.00	44.00	
4	CHERRYVILLE TIE CHERRYVILLE NC	TRANS	100.00	44.00	
5	CHERRYVILLE TIE CHERRYVILLE NC	TRANS	44.00	0.20	
6	CHESNEE RET CHESNEE SC	DIST	44.00	13.00	
7	CHESNEE RET CHESNEE SC	DIST	44.00	13.00	
8	CHESNEE TIE CHESNEE SC	TRANS	100.00	44.00	
9	CHESNEE TIE CHESNEE SC	TRANS	100.00	44.00	
10	CHESTER MAIN CHESTER SC	DIST	100.00	13.00	6.90
11	CHESTER MAIN CHESTER SC	DIST	100.00	13.00	6.90
12	CHESTER MAIN CHESTER SC	DIST	100.00	13.00	6.90
13	CHESTER MAIN CHESTER SC	DIST	100.00	13.00	6.90
14	CHESTER MAIN CHESTER SC	DIST	100.00	13.00	6.90
15	CHESTER MAIN CHESTER SC	DIST	100.00	44.00	13.00
16	CHESTER MAIN CHESTER SC	DIST	100.00	44.00	13.00
17	CHESTER MAIN CHESTER SC	DIST	100.00	44.00	13.00
18	CHESTER MAIN CHESTER SC	DIST	24.00	6.90	2.40
19	CHESTER MAIN CHESTER SC	DIST	24.00	6.90	2.40
20	CHESTER MAIN CHESTER SC	DIST	24.00	6.90	2.40
21	CHESTER MAIN CHESTER SC	DIST	24.00	6.90	2.40
22	CHINA GROVE MAIN CHINA GROVE NC	TRANS	100.00	44.00	
23	CHINA GROVE MAIN CHINA GROVE NC	TRANS	100.00	44.00	
24	CHINA GROVE MAIN CHINA GROVE NC	TRANS	100.00	44.00	
25	CHINA GROVE MAIN CHINA GROVE NC	TRANS	24.00	0.20	
26	CHINA GROVE RET CHINA GROVE NC	DIST	44.00	2.40	
27	CHINA GROVE RET CHINA GROVE NC	DIST	44.00	2.40	
28	CHINA GROVE RET CHINA GROVE NC	DIST	44.00	2.40	
29	CHINA GROVE RET CHINA GROVE NC	DIST	100.00	13.00	
30	CHRISTOPHER RD RET SHELBY NC	DIST	100.00	13.00	
31	CLAREMONT RET CLAREMONT NC	DIST	100.00	13.00	
32	CLAREMONT RET CLAREMONT NC	DIST	100.00	13.00	
33	CLARK HILL TIE GREENWOOD SC	TRANS	100.00	44.00	
34	CLARK HILL TIE GREENWOOD SC	TRANS	100.00	44.00	
35	CLARK HILL TIE GREENWOOD SC	TRANS	100.00	100.00	
36	CLARK HILL TIE GREENWOOD SC	TRANS	24.00	0.20	
37	CLEGHORN SS RUTHERFORDTON NC	DIST	44.00	13.00	
38	CLEMMONS RET CLEMMONS NC	DIST	100.00	13.00	
39	CLEMMONS RET CLEMMONS NC	DIST	100.00	13.00	
40	CLEMSON UNIV STA 2 CLEMSON SC	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) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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	CLEMSON UNIV STA 2 CLEMSON SC	DIST	44.00	13.00	
2	CLEVELAND RET CLEVELAND NC	DIST	100.00	13.00	6.90
3	CLEVELAND RET CLEVELAND NC	DIST	100.00	13.00	6.90
4	CLEVELAND RET CLEVELAND NC	DIST	100.00	13.00	6.90
5	CLEVELAND RET CLEVELAND NC	DIST	100.00	13.00	6.90
6	CLIFFSIDE STEAM STA 1-4 SW YD CLIFFSIDE NC	TRANS	4.10	0.40	
7	CLIFFSIDE STEAM STA 1-4 SW YD CLIFFSIDE NC	TRANS	4.10	0.40	
8	CLIFFSIDE STEAM STA 1-4 SW YD CLIFFSIDE NC	TRANS	44.00	13.00	
9	CLIFFSIDE STEAM STA 1-4 SW YD CLIFFSIDE NC	TRANS	44.00	0.60	2.40
10	CLIFFSIDE STEAM STA 1-4 SW YD CLIFFSIDE NC	TRANS	44.00	0.60	2.40
11	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	24.00	4.10	
12	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	230.00	4.10	
13	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	230.00	4.10	
14	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.40	
15	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.40	
16	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.40	
17	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	230.00	24.00	
18	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
19	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
20	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
21	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
22	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
23	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
24	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
25	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
26	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
27	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
28	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	230.00	100.00	44.00
29	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	230.00	100.00	44.00
30	CLIMAX RET CLIMAX NC	DIST	44.00	13.00	
31	CLIMAX RET CLIMAX NC	DIST	44.00	13.00	
32	CLINTON CITY CLINTON SC	DIST	100.00	24.00	13.00
33	CLINTON CITY CLINTON SC	DIST	100.00	24.00	13.00
34	CLINTON TIE CLINTON SC	TRANS	100.00	44.00	24.00
35	CLINTON TIE CLINTON SC	TRANS	100.00	44.00	24.00
36	CLINTON TIE CLINTON SC	TRANS	100.00	44.00	24.00
37	CLINTON TIE CLINTON SC	TRANS	100.00	44.00	24.00
38	CLINTON TIE CLINTON SC	TRANS	24.00	0.20	
39	CLOVER TIE CLOVER SC	TRANS	100.00	44.00	
40	CLOVER TIE CLOVER SC	TRANS	100.00	44.00	

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	CLOVER TIE CLOVER SC	TRANS	24.00	0.20	
2	CODDLE CREEK RET MOORESVILLE NC	DIST	44.00	13.00	
3	CODDLE CREEK RET MOORESVILLE NC	DIST	44.00	13.00	
4	COFFEY CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
5	COFFEY CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
6	COLFAX RET COLFAX NC	DIST	100.00	24.00	
7	COLFAX RET COLFAX NC	DIST	100.00	24.00	
8	COLUMBUS RET COLUMBUS NC	DIST	44.00	13.00	6.90
9	COLUMBUS RET COLUMBUS NC	DIST	44.00	13.00	6.90
10	COLUMBUS RET COLUMBUS NC	DIST	44.00	13.00	6.90
11	COLUMBUS RET COLUMBUS NC	DIST	44.00	13.00	6.90
12	COLUMBUS RET COLUMBUS NC	DIST	44.00	13.00	
13	COMMONWEALTH RET CHARLOTTE NC	DIST	100.00	13.00	
14	COMMONWEALTH RET CHARLOTTE NC	DIST	100.00	13.00	
15	COMMSCOPE SHERRILLS FORD T&D SHERRILLS FORD	DIST	44.00	13.00	
16	COMMSCOPE SHERRILLS FORD T&D SHERRILLS FORD	DIST	44.00	13.00	
17	CONCORD CITY DEL 1 CONCORD NC	DIST	100.00	44.00	
18	CONCORD CITY DEL 1 CONCORD NC	DIST	100.00	44.00	
19	CONCORD CITY DEL 1 CONCORD NC	DIST	24.00	0.20	
20	CONCORD MAIN CONCORD NC	TRANS	100.00	13.00	
21	CONCORD MAIN CONCORD NC	TRANS	100.00	13.00	
22	CONCORD MAIN CONCORD NC	TRANS	100.00	44.00	
23	CONCORD MAIN CONCORD NC	TRANS	100.00	44.00	
24	CONWAY RET GREENVILLE SC	DIST	100.00	13.00	
25	CONWAY RET GREENVILLE SC	DIST	100.00	13.00	
26	CORINTH RET ELLENBORO NC	DIST	44.00	13.00	
27	CORNING CABLE SYSTEMS T&D HICKORY NC	DIST	44.00	6.90	
28	CORNING CABLE SYSTEMS T&D HICKORY NC	DIST	44.00	6.90	
29	CORNING CABLE SYSTEMS T&D HICKORY NC	DIST	44.00	6.90	2.40
30	CORONACA RET CORONACA SC	DIST	44.00	13.00	
31	CORONACA RET CORONACA SC	DIST	44.00	13.00	
32	CORONACA TIE CORONACA SC	TRANS	100.00	44.00	
33	CORONACA TIE CORONACA SC	TRANS	100.00	44.00	
34	CORONACA TIE CORONACA SC	TRANS	100.00	44.00	
35	CORONACA TIE CORONACA SC	TRANS	24.00	0.20	
36	COTTONWOOD RET CORNELIUS NC	DIST	100.00	13.00	
37	COUNTRYSIDE RD RET KINGS MOUNTAIN NC	DIST	100.00	24.00	
38	COUNTRYSIDE RD RET KINGS MOUNTAIN NC	DIST	100.00	24.00	
39	COWANS FORD HYDRO STANLEY NC	TRANS	230.00	13.00	13.00
40	COWANS FORD HYDRO STANLEY NC	TRANS	230.00	13.00	13.00

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	COWANS FORD HYDRO STANLEY NC	TRANS	13.00	0.60	
2	COWANS FORD HYDRO STANLEY NC	TRANS	13.00	0.60	
3	COWANS FORD HYDRO STANLEY NC	TRANS	44.00	0.60	
4	COWPENS RET COWPENS SC	DIST	44.00	6.90	2.40
5	COWPENS RET COWPENS SC	DIST	44.00	6.90	2.40
6	COWPENS RET COWPENS SC	DIST	44.00	6.90	2.40
7	COWPENS RET COWPENS SC	DIST	44.00	6.90	2.40
8	COWPENS RET COWPENS SC	DIST	44.00	13.00	
9	CREST ST RET DURHAM NC	DIST	100.00	6.90	
10	CREST ST RET DURHAM NC	DIST	100.00	6.90	
11	CREST ST RET DURHAM NC	DIST	100.00	6.90	
12	CREST ST RET DURHAM NC	DIST	100.00	6.90	
13	CREST ST RET DURHAM NC	DIST	100.00	6.90	
14	CREST ST RET DURHAM NC	DIST	100.00	6.90	
15	CREST ST RET DURHAM NC	DIST	100.00	6.90	
16	CRETO TIE NINETY SIX SC	TRANS	100.00	44.00	
17	CRUMP RD RET HUDSON NC	DIST	100.00	13.00	
18	CRUMP RD RET HUDSON NC	DIST	100.00	13.00	
19	CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	
20	CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	
21	CYCLE RET ELKIN NC	DIST	44.00	13.00	
22	CYCLE RET ELKIN NC	DIST	44.00	13.00	
23	CYPRESS TIE ABBEVILLE SC	TRANS	100.00	44.00	
24	CYPRESS TIE ABBEVILLE SC	TRANS	100.00	44.00	
25	CYPRESS TIE ABBEVILLE SC	TRANS	24.00	0.20	
26	DACIAN AVE RET DURHAM NC	DIST	100.00	24.00	
27	DACIAN AVE RET DURHAM NC	DIST	100.00	24.00	
28	DALLAS CITY DEL 2 DALLAS NC	DIST	44.00	13.00	
29	DALLAS CITY DEL 2 DALLAS NC	DIST	44.00	13.00	
30	DAN RIVER STEAM STA EDEN NC	TRANS	138.00	100.00	13.80
31	DAN RIVER STEAM STA EDEN NC	TRANS	138.00	100.00	13.80
32	DAN RIVER STEAM STA EDEN NC	TRANS	138.00	100.00	13.80
33	DAN RIVER STEAM STA EDEN NC	TRANS	138.00	100.00	13.80
34	DAN RIVER STEAM STA EDEN NC	TRANS	2.40	0.60	
35	DAN VALLEY RET STONEVILLE NC	DIST	100.00	13.00	
36	DAN VALLEY RET STONEVILLE NC	DIST	100.00	13.00	
37	DANBURY RET DANBURY NC	DIST	44.00	24.00	13.00
38	DANIELS RET GREENVILLE SC	DIST	100.00	13.00	
39	DANIELS RET GREENVILLE SC	DIST	100.00	13.00	
40	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40

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	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
2	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
3	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
4	DAVIDSON RET DAVIDSON NC	DIST	44.00	13.00	
5	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
6	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
7	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
8	DAVIDSON RIVER RET PISGAH FOREST NC	TRANS	100.00	13.00	
9	DAVIS RET WILLIAMSTON SC	DIST	100.00	13.00	
10	DEARBORN HYDRO GREAT FALLS SC	TRANS	100.00	66.00	
11	DEARBORN HYDRO GREAT FALLS SC	TRANS	44.00	6.90	
12	DEARBORN HYDRO GREAT FALLS SC	TRANS	44.00	6.90	
13	DEERFIELD RET MOORESVILLE NC	DIST	100.00	13.00	
14	DENNY RD RET GREENSBORO NC	DIST	100.00	24.00	
15	DENNY RD RET GREENSBORO NC	DIST	100.00	24.00	
16	DENNY RD RET GREENSBORO NC	DIST	100.00	24.00	
17	DENTON RET DENTON NC	DIST	100.00	13.00	
18	DEPOT ST RET FRANKLIN NC	DIST	66.00		
19	DEPOT ST RET FRANKLIN NC	DIST	69.00	13.00	
20	DERITA RET CHARLOTTE NC	DIST	100.00	24.00	
21	DERITA RET CHARLOTTE NC	DIST	100.00	24.00	
22	DERITA RET CHARLOTTE NC	DIST	100.00	24.00	
23	DILWORTH DIST CHARLOTTE NC	DIST	24.00	2.40	0.60
24	DILWORTH DIST CHARLOTTE NC	DIST	24.00	2.40	0.60
25	DILWORTH DIST CHARLOTTE NC	DIST	24.00	2.40	0.60
26	DILWORTH DIST CHARLOTTE NC	DIST	24.00	2.40	0.60
27	DILWORTH DIST CHARLOTTE NC	DIST	24.00	6.90	2.40
28	DILWORTH DIST CHARLOTTE NC	DIST	24.00	6.90	2.40
29	DILWORTH DIST CHARLOTTE NC	DIST	24.00	6.90	2.40
30	DILWORTH DIST CHARLOTTE NC	DIST	24.00	6.90	2.40
31	DIXIE TIE GASTONIA NC	TRANS	100.00	44.00	
32	DIXIE TIE GASTONIA NC	TRANS	100.00	44.00	
33	DIXIE TIE GASTONIA NC	TRANS	100.00	0.20	
34	DIXON RET ANDERSON SC	DIST	100.00	13.00	
35	DOBSON RET DOBSON NC	DIST	44.00	6.90	
36	DOBSON RET DOBSON NC	DIST	44.00	6.90	
37	DOBSON RET DOBSON NC	DIST	44.00	6.90	2.40
38	DOBSON RET DOBSON NC	DIST	44.00	6.90	2.40
39	DOCHENO RET HONEA PATH SC	DIST	44.00	13.00	
40	DOCHENO RET HONEA PATH SC	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	DRAKA COMTEQ T&D CLAREMONT NC	DIST	100.00	24.00	13.00
2	DUKE UNIV MN DURHAM NC	DIST	100.00	44.00	
3	DUKE UNIV MN DURHAM NC	DIST	100.00	44.00	
4	DUKE UNIV MN DURHAM NC	DIST	100.00	44.00	
5	DUKE UNIV MN DURHAM NC	DIST	24.00	0.20	
6	DUKE UNIV MN DURHAM NC	DIST	24.00	0.20	
7	DUKE UNIV MN DURHAM NC	DIST	24.00	0.20	
8	DUKE UNIV MN DURHAM NC	DIST	24.00	0.20	
9	DUKE UNIV STA 1 DURHAM NC	DIST	44.00	13.00	
10	DUKE UNIV STA 1 DURHAM NC	DIST	44.00	13.00	
11	DUKE UNIV STA 2 DURHAM NC	DIST	44.00	13.00	
12	DUKE UNIV STA 2 DURHAM NC	DIST	44.00	13.00	
13	DUKE UNIV STA 2 DURHAM NC	DIST	44.00	13.00	
14	DUKE UNIV STA 3 DURHAM NC	DIST	44.00	13.00	
15	DUKE UNIV STA 3 DURHAM NC	DIST	44.00	13.00	
16	DUKE UNIV STA 4 DURHAM NC	DIST	44.00	13.00	
17	DUKE UNIV STA 4 DURHAM NC	DIST	44.00	13.00	
18	DUKE UNIV STA 5 DURHAM NC	DIST	44.00	13.00	
19	DUKE UNIV STA 5 DURHAM NC	DIST	44.00	13.00	
20	DUKE UNIV STA 5 DURHAM NC	DIST	44.00	13.00	
21	DUNBAR RET MOORESVILLE NC	DIST	100.00	13.00	
22	DUNBAR RET MOORESVILLE NC	DIST	100.00	13.00	
23	DUNCAN RET DUNCAN SC	DIST	44.00	13.00	
24	DUNCAN RET DUNCAN SC	DIST	44.00	13.00	
25	DURHAM MN DURHAM NC	DIST	100.00	13.00	
26	DURHAM MN DURHAM NC	DIST	100.00	13.00	
27	DURHAM MN DURHAM NC	DIST	100.00	13.00	
28	E BRYSON RET BRYSON CITY NC	DIST	66.00	13.00	
29	E CHESTER RET CHESTER SC	DIST	100.00	13.00	
30	E CHESTER RET CHESTER SC	DIST	100.00	13.00	
31	E DURHAM TIE DURHAM NC	TRANS	230.00	100.00	44.00
32	E DURHAM TIE DURHAM NC	TRANS	230.00	100.00	44.00
33	E DURHAM TIE DURHAM NC	TRANS	44.00	0.40	
34	E FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
35	E FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
36	E GANTT RET CONESTEE SC	DIST	44.00	13.00	
37	E GANTT RET CONESTEE SC	DIST	44.00	13.00	
38	E MAIDEN RET MAIDEN NC	DIST	44.00	6.90	
39	E MAIDEN RET MAIDEN NC	DIST	44.00	6.90	2.40
40	E MAIDEN RET MAIDEN NC	DIST	44.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	E MAIDEN RET MAIDEN NC	DIST	44.00	6.90	2.40
2	E MAIDEN RET MAIDEN NC	DIST	44.00	13.00	
3	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
4	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
5	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
6	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	6.90	2.40
7	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	6.90	2.40
8	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	6.90	2.40
9	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	6.90	2.40
10	E SPARTANBURG TIE SPARTANBURG SC	TRANS	44.00	6.90	2.40
11	E SPARTANBURG TIE SPARTANBURG SC	TRANS	44.00	6.90	2.40
12	E SPARTANBURG TIE SPARTANBURG SC	TRANS	44.00	6.90	2.40
13	E SYLVA RET SYLVA NC	DIST	66.00	13.00	
14	E SYLVA RET SYLVA NC	DIST	66.00	13.00	
15	E THOMASVILLE RET THOMASVILLE NC	DIST	100.00	13.00	
16	E THOMASVILLE RET THOMASVILLE NC	DIST	100.00	13.00	
17	EASLEY CITY DEL 3 EASLEY SC	DIST	100.00	24.00	13.00
18	EASLEY CITY DEL 3 EASLEY SC	DIST	100.00	44.00	24.00
19	EASLEY CITY DEL 4 EASLEY SC	DIST	100.00	13.00	
20	EASLEY MN EASLEY SC	TRANS	100.00	13.00	
21	EASLEY MN EASLEY SC	TRANS	100.00	13.00	
22	EASLEY MN EASLEY SC	TRANS	100.00	13.00	
23	EASLEY MN EASLEY SC	TRANS	100.00	44.00	
24	EASLEY MN EASLEY SC	TRANS	100.00	44.00	
25	EASTATOE RET PICKENS SC	DIST	100.00	13.00	
26	EASTFIELD RD RET CONCORD NC	DIST	100.00	13.00	
27	EASTFIELD RD RET CONCORD NC	DIST	100.00	24.00	
28	EASTGATE RET CHAPEL HILL NC	DIST	100.00	13.00	
29	EASTGATE RET CHAPEL HILL NC	DIST	100.00	13.00	
30	EASTOVER RET GREENVILLE SC	DIST	100.00	13.00	
31	EASTOVER RET GREENVILLE SC	DIST	100.00	13.00	
32	EASY ST RET CONCORD NC	DIST	44.00	13.00	
33	EBENEZER RET TRAVELERS REST SC	DIST	100.00	13.00	
34	EBERT RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
35	EDNEYVILLE RET HENDERSONVILLE NC	DIST	44.00	13.00	
36	EDNEYVILLE RET HENDERSONVILLE NC	DIST	44.00	13.00	
37	EFLAND RET EFLAND NC	DIST	44.00	13.00	
38	EFLAND RET EFLAND NC	DIST	44.00	13.00	
39	ELECTROLUX ANDERSON PL ANDERSON SC	DIST	44.00	13.00	
40	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	24.00	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	24.00	
2	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	24.00	
3	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	13.00	
4	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	13.00	
5	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	13.00	
6	ELIZABETH AVE RET CHARLOTTE NC	DIST	24.00	4.10	2.40
7	ELIZABETH AVE RET CHARLOTTE NC	DIST	24.00	4.10	2.40
8	ELK VALLEY RET ELKIN NC	DIST	100.00	13.00	
9	ELK VALLEY RET ELKIN NC	DIST	100.00	13.00	
10	ELKIN RET ELKIN NC	DIST	44.00	2.40	
11	ELKIN RET ELKIN NC	DIST	44.00	2.40	
12	ELKIN RET ELKIN NC	DIST	44.00	2.40	
13	ELKIN RET ELKIN NC	DIST	44.00	2.40	0.60
14	ELKIN RET ELKIN NC	DIST	44.00	6.90	2.40
15	ELKIN RET ELKIN NC	DIST	44.00	6.90	2.40
16	ELKIN RET ELKIN NC	DIST	44.00	6.90	2.40
17	ELKIN RET ELKIN NC	DIST	44.00	6.90	2.40
18	ELLERBEE RET CHAPEL HILL NC	DIST	100.00	13.00	
19	ELLIOTT RET SHELBY NC	DIST	100.00	13.00	
20	ELLIOTT RET SHELBY NC	DIST	100.00	13.00	
21	ELLIS RD RET DURHAM NC	DIST	100.00	24.00	
22	ELLIS RD RET DURHAM NC	DIST	100.00	24.00	
23	ELMWOOD RET ELMWOOD NC	DIST	100.00	24.00	
24	EMERALD RD RET GREENWOOD SC	DIST	100.00	13.00	
25	ENERGYUNITED EMC DEL 11 TAYLORSVILLE NC	DIST	100.00	24.00	13.00
26	ENERGYUNITED EMC DEL 11 TAYLORSVILLE NC	DIST	100.00	24.00	13.00
27	ENERGYUNITED EMC DEL 11 TAYLORSVILLE NC	DIST	100.00	24.00	13.00
28	ENERGYUNITED EMC DEL 11 TAYLORSVILLE NC	DIST	100.00	24.00	13.00
29	ENO RET DURHAM NC	DIST	44.00	24.00	
30	ENO RET DURHAM NC	DIST	44.00	24.00	13.00
31	ENO TIE DURHAM NC	TRANS	230.00	100.00	44.00
32	ENO TIE DURHAM NC	TRANS	230.00	100.00	44.00
33	ENO TIE DURHAM NC	TRANS	230.00	100.00	44.00
34	ENO TIE DURHAM NC	TRANS	230.00	100.00	13.00
35	ENO TIE DURHAM NC	TRANS	44.00		
36	ENO TIE DURHAM NC	TRANS	44.00		
37	ENO TIE DURHAM NC	TRANS	44.00	0.40	
38	ENO TIE DURHAM NC	TRANS	13.00	0.40	0.20
39	ENOCHVILLE RET KANNAPOLIS NC	DIST	100.00	13.00	
40	ENOCHVILLE RET KANNAPOLIS NC	DIST	100.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	ENOLA RET SPARTANBURG SC	DIST	100.00	13.00	
2	ENOLA RET SPARTANBURG SC	DIST	100.00	13.00	
3	FAIR GROVE RET THOMASVILLE NC	DIST	100.00	13.00	
4	FAIRFAX RD RET GREENSBORO NC	DIST	100.00	24.00	
5	FAIRFAX RD RET GREENSBORO NC	DIST	100.00	24.00	
6	FAIRFAX RD RET GREENSBORO NC	DIST	100.00	24.00	
7	FAIRNTOSH RET DURHAM NC	DIST	100.00	24.00	
8	FAIRNTOSH RET DURHAM NC	DIST	100.00	24.00	
9	FAIRPLAINS RET NORTH WILKESBORO NC	DIST	100.00	13.00	
10	FAIRPLAINS RET NORTH WILKESBORO NC	DIST	100.00	13.00	
11	FAIRVIEW TIE FOREST CITY NC	TRANS	100.00	44.00	
12	FAIRVIEW TIE FOREST CITY NC	TRANS	100.00	44.00	
13	FAIRVIEW TIE FOREST CITY NC	TRANS	100.00	44.00	
14	FAITH RET SALISBURY NC	DIST	100.00	13.00	
15	FAITH RET SALISBURY NC	DIST	100.00	13.00	
16	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	2.40
17	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	2.40
18	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	2.40
19	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	
20	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	
21	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	
22	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	2.40
23	FANTS GROVE RET PENDLETON SC	DIST	44.00	13.00	
24	FANTS GROVE RET PENDLETON SC	DIST	44.00	24.00	
25	FANTS GROVE RET PENDLETON SC	DIST	44.00	24.00	
26	FIDDLERS CREEK RET WINSTON-SALEM NC	DIST	100.00	13.00	
27	FIDDLERS CREEK RET WINSTON-SALEM NC	DIST	100.00	13.00	
28	FINGERVILLE RET FINGERVILLE SC	DIST	100.00	13.00	
29	FIRST ST RET HICKORY NC	DIST	44.00	13.00	4.10
30	FIRST ST RET HICKORY NC	DIST	44.00	13.00	4.10
31	FIRST ST RET HICKORY NC	DIST	44.00	6.90	2.40
32	FIRST ST RET HICKORY NC	DIST	44.00	6.90	2.40
33	FIRST ST RET HICKORY NC	DIST	44.00	6.90	2.40
34	FIRST ST RET HICKORY NC	DIST	44.00	6.90	2.40
35	FISHER SS CHARLOTTE NC	DIST	100.00	24.00	
36	FISHER SS CHARLOTTE NC	DIST	100.00	24.00	
37	FISHER SS CHARLOTTE NC	DIST	24.00	4.10	
38	FISHER SS CHARLOTTE NC	DIST	24.00	4.10	
39	FISHING CREEK HYDRO GREAT FALLS SC	TRANS	100.00	6.90	
40	FISHING CREEK HYDRO GREAT FALLS SC	TRANS	100.00	6.90	

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	FITESA SIMPSONVILLE T&D FOUNTAIN INN SC	DIST	100.00	24.00	
2	FLAT ROCK RET ANDERSON SC	DIST	44.00	13.00	
3	FLAT ROCK RET ANDERSON SC	DIST	44.00	13.00	
4	FLAT ROCK RET ANDERSON SC	DIST	44.00	13.00	
5	FLAY RET LINCOLNTON NC	DIST	44.00	6.90	2.40
6	FLAY RET LINCOLNTON NC	DIST	44.00	6.90	2.40
7	FLAY RET LINCOLNTON NC	DIST	44.00	6.90	2.40
8	FLAY RET LINCOLNTON NC	DIST	44.00	6.90	2.40
9	FLORIDA AVE RET GREENWOOD SC	DIST	44.00	6.90	2.40
10	FLORIDA AVE RET GREENWOOD SC	DIST	44.00	6.90	2.40
11	FLORIDA AVE RET GREENWOOD SC	DIST	44.00	6.90	2.40
12	FLORIDA AVE RET GREENWOOD SC	DIST	44.00	13.00	
13	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
14	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
15	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
16	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
17	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
18	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
19	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
20	FOREST CITY DEL 3 FOREST CITY NC	DIST	44.00	13.00	
21	FOREST CITY DEL 3 FOREST CITY NC	DIST	44.00	13.00	
22	FOREST HILL RET GREENWOOD SC	DIST	44.00	13.00	
23	FOREST HILL RET GREENWOOD SC	DIST	44.00	13.00	
24	FOREST LAKE RET FORT MILL SC	DIST	44.00	24.00	
25	FOUR SEASONS RET CHARLOTTE NC	DIST	100.00	24.00	
26	FOUR SEASONS RET CHARLOTTE NC	DIST	100.00	24.00	
27	FRIEDEN RET GIBSONVILLE NC	DIST	100.00	24.00	
28	FRIEDEN RET GIBSONVILLE NC	DIST	100.00	24.00	
29	FRIENDSHIP RET GREENSBORO NC	DIST	100.00	24.00	
30	FRIENDSHIP RET GREENSBORO NC	DIST	100.00	24.00	
31	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
32	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
33	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
34	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
35	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
36	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
37	FURR RD RET HUNTERSVILLE NC	DIST	44.00	13.00	
38	GAFFNEY CITY DEL 1A & 1B GAFFNEY SC	DIST	100.00	24.00	
39	GAFFNEY CITY DEL 1A & 1B GAFFNEY SC	DIST	100.00	24.00	
40	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	

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	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
2	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
3	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
4	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
5	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
6	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
7	GAFFNEY TIE GAFFNEY SC	TRANS	44.00	0.20	
8	GAFFNEY TIE GAFFNEY SC	TRANS	44.00	0.20	
9	GARRETT RD RET DURHAM NC	DIST	100.00	24.00	
10	GARRETT RD RET DURHAM NC	DIST	100.00	24.00	
11	GASTONIA CITY DEL 10 GASTONIA NC	DIST	100.00	13.00	
12	GASTONIA CITY DEL 10 GASTONIA NC	DIST	100.00	13.00	
13	GASTONIA CITY DEL 10 GASTONIA NC	DIST			
14	GASTONIA CITY DEL 11 GASTONIA NC	DIST	100.00	13.00	
15	GASTONIA CITY DEL 11 GASTONIA NC	DIST	100.00	13.00	
16	GASTONIA CITY DEL 12 GASTONIA NC	DIST	100.00	13.00	
17	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	
18	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	2.40
19	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	2.40
20	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	2.40
21	GASTONIA CITY DEL 6 GASTONIA NC	DIST	100.00	13.00	
22	GASTONIA CITY DEL 6 GASTONIA NC	DIST	100.00	13.00	
23	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	6.90	2.40
24	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	6.90	2.40
25	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	6.90	2.40
26	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	6.90	2.40
27	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	13.00	6.90
28	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	13.00	6.90
29	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	13.00	6.90
30	GASTONIA CITY DEL 9 GASTONIA NC	DIST	100.00	13.00	
31	GASTONIA CITY DEL 9 GASTONIA NC	DIST	100.00	13.00	
32	GATEWAY RET WHITTIER NC	DIST	66.00	13.00	
33	GATEWAY RET WHITTIER NC	DIST	66.00		
34	GATEWOOD RET GATEWOOD NC	DIST	44.00	13.00	
35	GENELEE RET DURHAM NC	DIST	100.00	24.00	
36	GENELEE RET DURHAM NC	DIST	100.00	24.00	
37	GILBREATH RET GRAHAM NC	DIST	100.00	24.00	
38	GILBREATH RET GRAHAM NC	DIST	100.00	24.00	
39	GILBREATH RET GRAHAM NC	DIST	24.00	13.00	
40	GILBREATH RET GRAHAM NC	DIST	24.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	13.00	
2	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	6.90	
3	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	6.90	
4	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	6.90	
5	GLEN RAVEN MN GLEN RAVEN NC	TRANS	100.00	24.00	
6	GLEN RAVEN MN GLEN RAVEN NC	TRANS	100.00	24.00	
7	GLEN RAVEN MN GLEN RAVEN NC	TRANS	100.00	24.00	
8	GLENOLA RET GLENOLA NC	DIST	100.00	13.00	
9	GLENOLA RET GLENOLA NC	DIST	100.00	13.00	
10	GLENWAY SS STATESVILLE NC	DIST	100.00	24.00	
11	GLENWOOD RET MARION NC	DIST	100.00	13.00	
12	GLENWOOD RET MARION NC	DIST	100.00	13.00	
13	GOODWILL CHURCH RD RET BELEWS CREEK NC	DIST	100.00	13.00	
14	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	13.00	
15	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	13.00	
16	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	24.00	
17	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	24.00	
18	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	24.00	
19	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
20	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
21	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
22	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
23	GRANITE FALLS CITY DEL 2 GRANITE FALLS NC	DIST	44.00	13.00	
24	GRASSY POND RET GRASSY POND SC	DIST	44.00	13.00	
25	GRASSY POND RET GRASSY POND SC	DIST	44.00	13.00	
26	GREAT FALLS HYDRO STA GREAT FALLS SC	TRANS	44.00	2.40	
27	GREAT FALLS HYDRO STA GREAT FALLS SC	TRANS	44.00	2.40	
28	GREAT FALLS HYDRO STA GREAT FALLS SC	TRANS	44.00	2.40	
29	GREAT FALLS HYDRO STA GREAT FALLS SC	TRANS	44.00	2.40	
30	GREAT FALLS SW STA GREAT FALLS SC	TRANS	100.00	44.00	
31	GREAT FALLS SW STA GREAT FALLS SC	TRANS	100.00	44.00	
32	GREEN POND RET ANDERSON SC	DIST	44.00	13.00	
33	GREEN POND RET ANDERSON SC	DIST	44.00	13.00	
34	GREEN ST RET DURHAM NC	DIST	100.00	13.00	
35	GREEN ST RET DURHAM NC	DIST	100.00	13.00	
36	GREENBRIAR SW STA SIMPSONVILLE SC	DIST	100.00	13.00	
37	GREENBRIAR SW STA SIMPSONVILLE SC	DIST	100.00	13.00	
38	GREENBRIAR SW STA SIMPSONVILLE SC	DIST	100.00	13.00	
39	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40
40	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40
2	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40
3	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
4	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
5	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
6	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
7	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
8	GREENVILLE MN GREENVILLE SC	TRANS	100.00	13.00	
9	GREENVILLE MN GREENVILLE SC	TRANS	100.00	13.00	
10	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
11	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
12	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
13	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	24.00
14	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
15	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
16	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
17	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
18	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
19	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
20	GREENVILLE MN GREENVILLE SC	TRANS	24.00	0.20	
21	GREENWOOD CITY DEL 1 GREENWOOD SC	DIST	44.00	13.00	
22	GREENWOOD CITY DEL 1 GREENWOOD SC	DIST	44.00	13.00	
23	GREENWOOD CITY DEL 3 GREENWOOD SC	DIST	44.00	13.00	
24	GREENWOOD CITY DEL 4 GREENWOOD SC	DIST	44.00	13.00	
25	GREENWOOD CITY DEL 4 GREENWOOD SC	DIST	44.00	13.00	
26	GREENWOOD CITY DEL 5 GREENWOOD SC	DIST	44.00	13.00	
27	GREENWOOD TIE GREENWOOD SC	TRANS	100.00	44.00	
28	GREENWOOD TIE GREENWOOD SC	TRANS	100.00	44.00	
29	GREENWOOD TIE GREENWOOD SC	TRANS	100.00	44.00	
30	GREENWOOD TIE GREENWOOD SC	TRANS	24.00	0.20	
31	GREER CITY STA 2 GREER SC	DIST	100.00	13.00	4.10
32	GREER CITY STA 2 GREER SC	DIST	100.00	13.00	4.10
33	GREER RET GREER SC	DIST	100.00	13.00	
34	GREY RET CHAPEL HILL NC	DIST	100.00	13.00	
35	GREY RET CHAPEL HILL NC	DIST	100.00	13.00	
36	GRIFFITH RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
37	GRIFFITH RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
38	GROOMTOWN RET GREENSBORO NC	DIST	100.00	24.00	
39	GROOMTOWN RET GREENSBORO NC	DIST	100.00	24.00	
40	GROOMTOWN RET GREENSBORO NC	DIST	100.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
2	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
3	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
4	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
5	GUTHRIE RET WINSTON-SALEM NC	DIST	100.00	13.00	
6	GUTHRIE RET WINSTON-SALEM NC	DIST	100.00	13.00	
7	HAMPTON AVE RET SPARTANBURG SC	DIST	100.00	13.00	
8	HAMPTON AVE RET SPARTANBURG SC	DIST	100.00	13.00	
9	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
10	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
11	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
12	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
13	HARRISBURG TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
14	HARRISBURG TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
15	HARRISBURG TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
16	HARRISBURG TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
17	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00		
18	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	0.60	
19	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	0.60	
20	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	0.60	
21	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	2.40	0.60
22	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	2.40	0.60
23	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	2.40	0.60
24	HARTFORD AVE RET BESSEMER CITY NC	DIST	44.00	13.00	
25	HARTFORD AVE RET BESSEMER CITY NC	DIST	44.00	13.00	
26	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
27	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
28	HAW RIVER RET HAW RIVER NC	DIST	44.00	13.00	
29	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
30	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
31	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	24.00	
32	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	24.00	
33	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
34	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
35	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
36	HAYS RET HAYS NC	DIST	44.00	13.00	
37	HEATH RET RANDLEMAN NC	DIST	100.00	13.00	
38	HEATH RET RANDLEMAN NC	DIST	100.00	13.00	
39	HENDERSONVILLE TIE EAST FLAT ROCK NC	TRANS	100.00	44.00	
40	HENDERSONVILLE TIE EAST FLAT ROCK NC	TRANS	100.00	44.00	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	HENDERSONVILLE TIE EAST FLAT ROCK NC	TRANS	24.00	0.20	
2	HENSLEY RD RET FORT MILL SC	DIST	13.00	2.40	
3	HENSLEY RD RET FORT MILL SC	DIST	13.00	2.40	
4	HENSLEY RD RET FORT MILL SC	DIST	13.00	2.40	
5	HENSLEY RD RET FORT MILL SC	DIST	13.00	2.40	
6	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
7	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
8	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
9	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
10	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
11	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
12	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
13	HICKORY GROVE RET CHARLOTTE NC	DIST	100.00	13.00	
14	HICKORY GROVE RET CHARLOTTE NC	DIST	100.00	13.00	
15	HICKORY GROVE RET CHARLOTTE NC	DIST	100.00	13.00	
16	HICKORY TIE HICKORY NC	TRANS	100.00	44.00	
17	HICKORY TIE HICKORY NC	TRANS	100.00	44.00	
18	HICKORY TIE HICKORY NC	TRANS	100.00	44.00	
19	HICKORY TIE HICKORY NC	TRANS	24.00	0.20	
20	HIDDENITE RET HIDDENITE NC	DIST	44.00	13.00	
21	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	
22	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	
23	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	2.40
24	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	2.40
25	HIGH SHOALS RET HIGH SHOALS NC	DIST	13.00	2.40	
26	HIGH SHOALS RET HIGH SHOALS NC	DIST	13.00	2.40	
27	HIGH SHOALS RET HIGH SHOALS NC	DIST	13.00	2.40	
28	HIGH SHOALS RET HIGH SHOALS NC	DIST	44.00	13.00	
29	HIGH SHOALS RET HIGH SHOALS NC	DIST	44.00	13.00	13.00
30	HIGHLANDS RET HIGHLANDS NC	DIST	66.00	13.00	
31	HIGHLANDS RET HIGHLANDS NC	DIST	66.00	13.00	
32	HIGHTOWER RET TAYLORS SC	DIST	100.00	13.00	
33	HIGHTOWER RET TAYLORS SC	DIST	100.00	13.00	
34	HILL ST RET CHARLOTTE NC	DIST	100.00	24.00	
35	HILL ST RET CHARLOTTE NC	DIST	100.00	24.00	
36	HILL ST RET CHARLOTTE NC	DIST	100.00	24.00	
37	HILLBROOK RET SPARTANBURG SC	DIST	100.00	13.00	
38	HILLBROOK RET SPARTANBURG SC	DIST	100.00	13.00	
39	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
40	HILLSBOROUGH RET HILLSBOROUGH 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
2	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	
3	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	
4	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
5	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	100.00	44.00	
6	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	100.00	44.00	
7	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	100.00	44.00	
8	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	100.00	44.00	
9	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	24.00	0.20	
10	HINSHAW RET WINSTON-SALEM NC	DIST	100.00	13.00	
11	HINSHAW RET WINSTON-SALEM NC	DIST	100.00	13.00	
12	HINSHAW RET WINSTON-SALEM NC	DIST	100.00	13.00	
13	HITACHI METALS LTD CHINA GROVE NC	DIST	44.00	13.00	
14	HODGES TIE HODGES SC	TRANS	230.00	100.00	44.00
15	HODGES TIE HODGES SC	TRANS	230.00	100.00	44.00
16	HODGES TIE HODGES SC	TRANS	44.00		
17	HODGES TIE HODGES SC	TRANS	44.00	0.40	
18	HOLCOMBE RD RET PIEDMONT SC	DIST	100.00	13.00	
19	HOLLY HILL RET THOMASVILLE NC	DIST	100.00	13.00	
20	HOLLY HILL RET THOMASVILLE NC	DIST	100.00	13.00	
21	HOMESTEAD RET CHAPEL HILL NC	DIST	100.00	13.00	
22	HOMESTEAD RET CHAPEL HILL NC	DIST	100.00	13.00	
23	HOPE VALLEY RET DURHAM NC	DIST	100.00	13.00	
24	HOPE VALLEY RET DURHAM NC	DIST	100.00	13.00	
25	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	
26	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	2.40
27	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	2.40
28	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	2.40
29	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	100.00	13.00
30	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	100.00	13.00
31	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	44.00	
32	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	44.00	
33	HORSESHOE TIE HENDERSONVILLE NC	TRANS	24.00	0.20	
34	HORSESHOE TIE HENDERSONVILLE NC	TRANS	24.00	0.20	
35	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	44.00	
36	HORSESHOE TIE HENDERSONVILLE NC	TRANS	24.00	0.20	
37	HORTON RD RET DURHAM NC	DIST	100.00	13.00	
38	HORTON RD RET DURHAM NC	DIST	100.00	13.00	
39	HUDLOW RET RUTHERFORDTON NC	DIST	100.00	13.00	
40	HUDSON ST RET GREENVILLE SC	DIST	100.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	HUDSON ST RET GREENVILLE SC	DIST	100.00	13.00	
2	HUDSON ST RET GREENVILLE SC	DIST	100.00	13.00	
3	HUNTERSVILLE CITY HUNTERSVILLE NC	DIST	44.00	13.00	
4	HUNTERSVILLE CITY HUNTERSVILLE NC	DIST	44.00	13.00	
5	HURRICANE CREEK RET ANDERSON SC	DIST	100.00	13.00	
6	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	13.00	
7	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	13.00	
8	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	24.00	
9	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	24.00	
10	ICARD RET ICARD NC	DIST	44.00	6.90	
11	ICARD RET ICARD NC	DIST	44.00	6.90	
12	ICARD RET ICARD NC	DIST	44.00	6.90	
13	ICARD RET ICARD NC	DIST	44.00	6.90	
14	ICARD RET ICARD NC	DIST	44.00	6.90	
15	ICARD RET ICARD NC	DIST	44.00	6.90	
16	ICARD RET ICARD NC	DIST	44.00	6.90	
17	IMPERIAL RET DURHAM NC	DIST	100.00	24.00	
18	IMPERIAL RET DURHAM NC	DIST	100.00	24.00	
19	IMPERIAL RET DURHAM NC	DIST	100.00	24.00	
20	INDIAN LAND RET FORT MILL SC	DIST	100.00	13.00	
21	INDIAN LAND RET FORT MILL SC	DIST	100.00	24.00	
22	INMAN TIE INMAN SC	TRANS	100.00	44.00	
23	INMAN TIE INMAN SC	TRANS	100.00	44.00	
24	INMAN TIE INMAN SC	TRANS	100.00	44.00	
25	ISLAND FORD RD RET STATESVILLE NC	DIST	100.00	13.00	
26	JAMES ST RET CHAPEL HILL NC	DIST	100.00	13.00	6.90
27	JAMES ST RET CHAPEL HILL NC	DIST	100.00	13.00	
28	JENKINS BRANCH RET BRYSON CITY NC	DIST	66.00	13.00	
29	JENKINS BRANCH RET BRYSON CITY NC	DIST	66.00	13.00	
30	JESSUPTOWN RET GREENSBORO NC	DIST	100.00	24.00	
31	JESSUPTOWN RET GREENSBORO NC	DIST	100.00	24.00	
32	JESSUPTOWN RET GREENSBORO NC	DIST	100.00	24.00	
33	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
34	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
35	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
36	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
37	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
38	JOCASSEE HYDRO JOCASSEE SC	TRANS	4.10	0.60	
39	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
40	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
2	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
3	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
4	JOCASSEE HYDRO JOCASSEE SC	TRANS	4.10	0.60	
5	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
6	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
7	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.60	
8	JOCASSEE TIE JOCASSEE SC	TRANS	500.00	230.00	24.00
9	JOCASSEE TIE JOCASSEE SC	TRANS	500.00	230.00	24.00
10	JOCASSEE TIE JOCASSEE SC	TRANS	500.00	230.00	24.00
11	JOCASSEE TIE JOCASSEE SC	TRANS	230.00	13.00	13.00
12	JOHNS CREEK RET GREENWOOD SC	DIST	100.00	13.00	
13	JOHNS CREEK RET GREENWOOD SC	DIST	100.00	13.00	
14	JULIAN RD RET SALISBURY NC	DIST	100.00	13.00	
15	KANUGA RET HENDERSONVILLE NC	DIST	44.00	13.00	
16	KANUGA RET HENDERSONVILLE NC	DIST	44.00	13.00	
17	KENILWORTH RET CHARLOTTE NC	DIST	100.00	13.00	
18	KENILWORTH RET CHARLOTTE NC	DIST	100.00	13.00	
19	KENILWORTH RET CHARLOTTE NC	DIST	100.00	13.00	
20	KEOWEE HYDRO NEWRY SC	TRANS	230.00	13.00	13.00
21	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.20	
22	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.20	
23	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.60	
24	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.20	
25	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.60	
26	KEOWEE HYDRO NEWRY SC	TRANS	4.10	0.60	
27	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
28	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	44.00	13.00
29	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	44.00	13.00
30	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	44.00	13.00
31	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
32	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
33	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
34	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	24.00	13.00
35	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
36	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
37	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
38	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
39	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
40	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
2	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
3	KEY ST RET PILOT MOUNTAIN NC	DIST	44.00	13.00	
4	KEY ST RET PILOT MOUNTAIN NC	DIST	44.00	13.00	
5	KILDARE RET GREENSBORO NC	DIST	100.00	24.00	
6	KILDARE RET GREENSBORO NC	DIST	100.00	24.00	
7	KIMESVILLE RET KIMESVILLE NC	DIST	44.00	13.00	
8	KIMESVILLE RET KIMESVILLE NC	DIST	44.00	13.00	
9	KINCAID RD RET HUDSON NC	DIST	100.00	13.00	
10	KINCAID RD RET HUDSON NC	DIST	100.00	13.00	
11	KING RET KING NC	DIST	100.00	13.00	
12	KING RET KING NC	DIST	100.00	13.00	
13	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
14	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
15	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
16	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
17	KINGS MTN MAIN KINGS MOUNTAIN NC	DIST	44.00	13.00	
18	KINGS MTN MAIN KINGS MOUNTAIN NC	DIST	44.00	13.00	
19	KINGSGATE RET GREENVILLE SC	DIST	100.00	13.00	
20	KIT CREEK RET DURHAM NC	DIST	100.00	24.00	
21	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
22	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
23	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
24	KIVETT DR RET HIGH POINT NC	DIST	24.00	13.00	13.00
25	KIVETT DR RET HIGH POINT NC	DIST	24.00	13.00	13.00
26	KIVETT DR RET HIGH POINT NC	DIST	24.00	13.00	13.00
27	KIVETT DR RET HIGH POINT NC	DIST	24.00	13.00	13.00
28	KNIGHTS RET ROCK HILL SC	DIST	100.00	24.00	
29	KNOLLWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
30	KNOLLWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
31	KUDZU RET CHARLOTTE NC	DIST	100.00	24.00	
32	KUDZU RET CHARLOTTE NC	DIST	100.00	13.00	
33	LAKE EMORY TIE FRANKLIN NC	TRANS	161.00	66.00	
34	LAKE EMORY TIE FRANKLIN NC	TRANS	161.00	66.00	
35	LAKE EMORY TIE FRANKLIN NC	TRANS	161.00	66.00	
36	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	0.60
37	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	0.60
38	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	0.60
39	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	
40	LAKE EMORY TIE FRANKLIN NC	TRANS	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	
2	LAKE EMORY TIE FRANKLIN NC	TRANS	66.00	2.40	
3	LAKE LURE RET LAKE LURE NC	DIST	44.00	6.90	2.40
4	LAKE LURE RET LAKE LURE NC	DIST	44.00	6.90	2.40
5	LAKE LURE RET LAKE LURE NC	DIST	44.00	6.90	2.40
6	LAKE LURE RET LAKE LURE NC	DIST	44.00	6.90	2.40
7	LAKE LURE RET LAKE LURE NC	DIST	44.00	13.00	
8	LAKE TOWNSEND RET GREENSBORO NC	DIST	100.00	24.00	
9	LAKE TOWNSEND RET GREENSBORO NC	DIST	100.00	24.00	
10	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	6.90	
11	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	6.90	
12	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	6.90	
13	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	6.90	
14	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	13.00	6.90
15	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	13.00	6.90
16	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	13.00	6.90
17	LAKEWOOD RET CHARLOTTE NC	DIST	44.00	4.10	
18	LAKEWOOD RET CHARLOTTE NC	DIST	44.00	4.10	
19	LAKEWOOD TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
20	LAKEWOOD TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
21	LAKEWOOD TIE CHARLOTTE NC	TRANS	44.00		
22	LAKEWOOD TIE CHARLOTTE NC	TRANS	44.00		
23	LAKEWOOD TIE CHARLOTTE NC	TRANS	44.00	0.40	
24	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	
25	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	
26	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	
27	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	
28	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	24.00
29	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	24.00
30	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	24.00
31	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	24.00
32	LANCASTER MN LANCASTER SC	TRANS	24.00	0.20	
33	LANCASTER RET LANCASTER SC	DIST	100.00	2.40	
34	LANCASTER RET LANCASTER SC	DIST	100.00	2.40	
35	LANCASTER RET LANCASTER SC	DIST	100.00	2.40	
36	LANCASTER RET LANCASTER SC	DIST	100.00	2.40	
37	LANCASTER RET LANCASTER SC	DIST	100.00	13.00	
38	LANCASTER RET LANCASTER SC	DIST	100.00	13.00	
39	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	2.40	
40	LANDIS CITY DEL 1&2 LANDIS 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	2.40	
2	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	2.40	
3	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	13.00	
4	LANDO RET LANDO SC	DIST	44.00	13.00	
5	LANDO RET LANDO SC	DIST	44.00	13.00	
6	LANDRUM RET LANDRUM SC	DIST	44.00	13.00	
7	LANDRUM RET LANDRUM SC	DIST	44.00	6.90	
8	LANDRUM RET LANDRUM SC	DIST	44.00	6.90	
9	LANDRUM RET LANDRUM SC	DIST	44.00	6.90	
10	LANGSTON CREEK RET GREENVILLE SC	DIST	100.00	13.00	
11	LANGSTON CREEK RET GREENVILLE SC	DIST	100.00	13.00	
12	LANGTREE RET MOORESVILLE NC	DIST	100.00	13.00	
13	LAUREL CREEK RET GREENVILLE SC	DIST	100.00	13.00	
14	LAUREL CREEK RET GREENVILLE SC	DIST	100.00	13.00	
15	LAURENS CITY CAROLINE STA LAURENS SC	DIST	100.00	13.00	
16	LAURENS CITY CAROLINE STA LAURENS SC	DIST	100.00	13.00	
17	LAURENS E C DEL 10 LAURENS LAURENS SC	DIST	44.00	6.90	
18	LAURENS E C DEL 10 LAURENS LAURENS SC	DIST	44.00	6.90	2.40
19	LAURENS E C DEL 10 LAURENS LAURENS SC	DIST	44.00	6.90	2.40
20	LAURENS E C DEL 25 MAULDIN MAULDIN SC	DIST	100.00	13.00	4.10
21	LAURENS E C DEL 25 MAULDIN MAULDIN SC	DIST	100.00	13.00	
22	LAURENS E C DEL 26 WALNUT GROVE SC	DIST	100.00	13.00	
23	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
24	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
25	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
26	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
27	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
28	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
29	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
30	LAURENS TIE LAURENS SC	TRANS	44.00	13.00	6.90
31	LAURENS TIE LAURENS SC	TRANS	44.00	13.00	6.90
32	LAURENS TIE LAURENS SC	TRANS	44.00	13.00	6.90
33	LAURENS TIE LAURENS SC	TRANS	44.00	13.00	6.90
34	LAWNDALE RET LAWNDALE NC	DIST	44.00	13.00	
35	LAWSONS FORK TIE SPARTANBURG SC	TRANS	100.00	44.00	
36	LAWSONS FORK TIE SPARTANBURG SC	TRANS	100.00	44.00	
37	LEAFCREST RET CHARLOTTE NC	DIST	100.00	13.00	
38	LEE STEAM STA COMB TURB PELZER SC	TRANS	100.00	13.00	
39	LEE STEAM STA COMB TURB PELZER SC	TRANS	100.00	13.00	
40	LELIA RET WELLFORD SC	DIST	100.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	LELIA RET WELLFORD SC	DIST	100.00	13.00	
2	LESLIE RET LESLIE SC	DIST	44.00	6.90	2.40
3	LESLIE RET LESLIE SC	DIST	44.00	6.90	2.40
4	LESLIE RET LESLIE SC	DIST	44.00	6.90	2.40
5	LESLIE RET LESLIE SC	DIST	44.00	6.90	
6	LESLIE RET LESLIE SC	DIST	44.00	13.00	
7	LEWISVILLE RET LEWISVILLE NC	DIST	100.00	13.00	
8	LEWISVILLE RET LEWISVILLE NC	DIST	100.00	13.00	
9	LEXINGTON CITY DEL 1 LEXINGTON NC	DIST	100.00	44.00	
10	LEXINGTON CITY DEL 1 LEXINGTON NC	DIST	100.00	44.00	
11	LEXINGTON CITY DEL 1 LEXINGTON NC	DIST	24.00	0.20	
12	LEXINGTON MN LEXINGTON NC	DIST	100.00	24.00	
13	LEXINGTON MN LEXINGTON NC	DIST	100.00	24.00	
14	LEXINGTON MN LEXINGTON NC	DIST	100.00	13.00	6.90
15	LEXINGTON MN LEXINGTON NC	DIST	100.00	13.00	6.90
16	LEXINGTON MN LEXINGTON NC	DIST	100.00	13.00	6.90
17	LEXINGTON MN LEXINGTON NC	DIST	100.00	13.00	6.90
18	LIBERTY RET NEW LIBERTY SC	DIST	100.00	13.00	
19	LIBERTY RET NEW LIBERTY SC	DIST	100.00	13.00	
20	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
21	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
22	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
23	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
24	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
25	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
26	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
27	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
28	LINCOLNTON CITY LINCOLNTON NC	DIST	100.00	13.00	6.90
29	LINCOLNTON CITY LINCOLNTON NC	DIST	100.00	13.00	6.90
30	LINCOLNTON CITY LINCOLNTON NC	DIST	100.00	13.00	6.90
31	LINCOLNTON CITY LINCOLNTON NC	DIST	100.00	13.00	6.90
32	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	13.00	
33	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	13.00	
34	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	44.00	
35	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	44.00	
36	LINDE LLC MIDLAND NC	TRANS	100.00	13.00	
37	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
38	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
39	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
40	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	24.00	13.00

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
2	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
3	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
4	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	6.90	
5	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	6.90	
6	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
7	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
8	LINWOOD SS LEXINGTON NC	DIST	100.00	44.00	24.00
9	LIONS MOUNTAIN TIE CALVERT NC	TRANS	100.00	44.00	
10	LIONS MOUNTAIN TIE CALVERT NC	TRANS	100.00	44.00	
11	LIONS MOUNTAIN TIE CALVERT NC	TRANS	44.00	4.10	2.40
12	LIONS MOUNTAIN TIE CALVERT NC	TRANS		4.60	
13	LITTLE ROCK RET CHARLOTTE NC	DIST	100.00	13.00	
14	LITTLE ROCK RET CHARLOTTE NC	DIST	100.00	13.00	
15	LITTLE ROCK RET CHARLOTTE NC	DIST	100.00	24.00	
16	LOCKHART POWER CO DEL 1 PACOLET SC	DIST	100.00	44.00	33.00
17	LOCKHART POWER CO DEL 1 PACOLET SC	DIST	100.00	44.00	33.00
18	LOCKHART POWER CO DEL 1 PACOLET SC	DIST	33.00		
19	LOCUST RET LOCUST NC	DIST	100.00	13.00	
20	LONG FERRY RET SALISBURY NC	DIST	100.00	13.00	
21	LONG FERRY RET SALISBURY NC	DIST	100.00	13.00	
22	LONGVIEW RET LONG VIEW NC	DIST	44.00	13.00	
23	LONGVIEW RET LONG VIEW NC	DIST	44.00	13.00	
24	LONGVIEW TIE LONG VIEW NC	TRANS	230.00	100.00	44.00
25	LONGVIEW TIE LONG VIEW NC	TRANS	230.00	100.00	44.00
26	LONGVIEW TIE LONG VIEW NC	TRANS	230.00	100.00	44.00
27	LONGVIEW TIE LONG VIEW NC	TRANS	230.00	100.00	44.00
28	LONGVIEW TIE LONG VIEW NC	TRANS	44.00		
29	LONGVIEW TIE LONG VIEW NC	TRANS	44.00		
30	LONGVIEW TIE LONG VIEW NC	TRANS	44.00	6.90	2.40
31	LONGVIEW TIE LONG VIEW NC	TRANS	44.00	6.90	2.40
32	LONGVIEW TIE LONG VIEW NC	TRANS	44.00	6.90	2.40
33	LOOKOUT HYDRO STATESVILLE NC	TRANS	100.00	6.90	
34	LOOKOUT HYDRO STATESVILLE NC	TRANS	100.00	6.90	
35	LOOKOUT TIE STATESVILLE NC	TRANS	100.00	44.00	
36	LOOKOUT TIE STATESVILLE NC	TRANS	100.00	44.00	
37	LOOKOUT TIE STATESVILLE NC	TRANS	100.00	44.00	
38	LOOKOUT TIE STATESVILLE NC	TRANS	24.00	0.20	
39	LUMBER LANE RET MOUNT HOLLY NC	DIST	100.00	13.00	
40	LUNSFORD RD RET KING NC	DIST	100.00	13.00	

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	MACEDONIA RET TAYLORSVILLE NC	DIST	100.00	13.00	
2	MADISON RET MADISON NC	DIST	100.00	13.00	
3	MADISON RET MADISON NC	DIST	100.00	13.00	
4	MADISON TIE MADISON NC	TRANS	100.00	44.00	
5	MADISON TIE MADISON NC	TRANS	100.00	44.00	
6	MADISON TIE MADISON NC	TRANS	100.00	44.00	
7	MAIDEN CITY DEL 2 MAIDEN NC	DIST	44.00	13.00	
8	MAIDEN CITY DEL 2 MAIDEN NC	DIST	44.00	13.00	
9	MAJOLICA RD RET SALISBURY NC	DIST	100.00	13.00	
10	MALLARD CREEK RET CHARLOTTE NC	DIST	100.00	13.00	
11	MALLARD CREEK RET CHARLOTTE NC	DIST	100.00	13.00	
12	MANCHESTER RET KANNAPOLIS NC	DIST	100.00	13.00	
13	MARBLE TIE MARBLE NC	TRANS	161.00	34.50	
14	MARBLE TIE MARBLE NC	TRANS	161.00	34.50	
15	MARBLE TIE MARBLE NC	TRANS	34.50	13.00	
16	MARBLE TIE MARBLE NC	TRANS	13.00	0.40	
17	MARBLE TIE MARBLE NC	TRANS	13.00	0.40	
18	MARBLE TIE MARBLE NC	TRANS	13.00	0.40	
19	MAR-DON DR RET WINSTON-SALEM NC	DIST	100.00	13.00	
20	MAR-DON DR RET WINSTON-SALEM NC	DIST	100.00	24.00	
21	MARIETTA TIE MARIETTA SC	TRANS	100.00	44.00	
22	MARIETTA TIE MARIETTA SC	TRANS	100.00	44.00	
23	MARIETTA TIE MARIETTA SC	TRANS	24.00	0.20	
24	MARION MN MARION NC	DIST	100.00	13.00	6.90
25	MARION MN MARION NC	DIST	100.00	13.00	6.90
26	MARION MN MARION NC	DIST	100.00	13.00	6.90
27	MARION MN MARION NC	DIST	100.00	13.00	6.90
28	MARION MN MARION NC	DIST	44.00	6.90	2.40
29	MARION MN MARION NC	DIST	44.00	6.90	2.40
30	MARION MN MARION NC	DIST	44.00	6.90	2.40
31	MARION MN MARION NC	DIST	44.00	6.90	2.40
32	MARKET POINT RET GREENVILLE SC	DIST	100.00	13.00	
33	MARSHALL RET TERRELL NC	DIST	44.00	13.00	
34	MARSHALL STEAM STA YARD TERRELL NC	TRANS	230.00	24.00	
35	MARSHALL STEAM STA YARD TERRELL NC	TRANS	230.00	24.00	
36	MARSHALL STEAM STA YARD TERRELL NC	TRANS	230.00	24.00	
37	MARSHALL STEAM STA YARD TERRELL NC	TRANS	230.00	24.00	
38	MARSHALL STEAM STA YARD TERRELL NC	TRANS	4.10	0.60	
39	MARSHALL STEAM STA YARD TERRELL NC	TRANS	4.10	0.60	
40	MARSHALL STEAM STA YARD TERRELL NC	TRANS			

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	MARSHALL STEAM STA YARD TERRELL NC	TRANS			
2	MASONIC DR DIST GREENSBORO NC	DIST	13.00	2.40	
3	MASONIC DR DIST GREENSBORO NC	DIST	13.00	2.40	
4	MASCOT RET INMAN SC	DIST	44.00	13.00	
5	MASCOT RET INMAN SC	DIST	44.00	13.00	
6	MATTHEWS RET CHARLOTTE NC	DIST	100.00	24.00	
7	MATTHEWS RET CHARLOTTE NC	DIST	100.00	24.00	
8	MATTHEWS RET CHARLOTTE NC	DIST	100.00	24.00	
9	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	100.00	44.00	
10	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	100.00	44.00	
11	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	100.00	44.00	
12	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	44.00	13.00	
13	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	44.00	13.00	
14	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	24.00	0.20	
15	MCALPINE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
16	MCALPINE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
17	MCALPINE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
18	MCDOWELL TIE MARION NC	TRANS	230.00	100.00	44.00
19	MCDOWELL TIE MARION NC	TRANS	100.00	44.00	
20	MCDOWELL TIE MARION NC	TRANS	44.00	24.00	
21	MCDOWELL TIE MARION NC	TRANS	44.00	24.00	
22	MCDOWELL TIE MARION NC	TRANS	44.00	24.00	
23	MCDOWELL TIE MARION NC	TRANS	44.00	2.40	0.60
24	MCDOWELL TIE MARION NC	TRANS	44.00	2.40	0.60
25	MCDOWELL TIE MARION NC	TRANS	44.00	2.40	0.60
26	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	500.00	24.00	
27	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	24.00	6.90	6.90
28	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	24.00	6.90	6.90
29	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	4.10	
30	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	4.10	
31	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	24.00	13.00	
32	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	500.00	24.00	
33	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
34	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
35	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
36	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
37	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
38	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
39	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
40	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
2	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
3	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
4	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
5	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
6	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
7	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
8	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
9	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
10	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
11	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
12	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
13	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
14	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
15	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
16	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
17	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00	230.00	24.00
18	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00	230.00	24.00
19	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00	230.00	24.00
20	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00	230.00	24.00
21	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	6.90	4.10	
22	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	24.00	4.10	
23	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
24	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
25	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
26	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
27	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
28	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
29	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS			
30	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS			
31	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS			
32	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	4.10		
33	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
34	MEADOW GREEN RET EDEN NC	DIST	100.00	13.00	
35	MEADOW GREEN RET EDEN NC	DIST	100.00	13.00	
36	MEBANE RET MEBANE NC	DIST	44.00	2.40	
37	MEBANE RET MEBANE NC	DIST	44.00	2.40	
38	MEBANE RET MEBANE NC	DIST	44.00	2.40	
39	MEBANE RET MEBANE NC	DIST	44.00	2.40	
40	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
2	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
3	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
4	MEBANE RET MEBANE NC	DIST	44.00	13.00	
5	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
6	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
7	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
8	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
9	MEBANE TIE MEBANE NC	TRANS	24.00	0.20	
10	MERRITT DR RET GREENSBORO NC	DIST	100.00	24.00	
11	MERRITT DR RET GREENSBORO NC	DIST	100.00	24.00	
12	MIDWAY SS UNION SC	TRANS	100.00	33.00	
13	MIDWAY SS UNION SC	TRANS	100.00	33.00	
14	MILLER HILL RET LENOIR NC	DIST	100.00	13.00	
15	MILLER HILL RET LENOIR NC	DIST	100.00	13.00	
16	MILLER HILL RET LENOIR NC	DIST	100.00	13.00	
17	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
18	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
19	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
20	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
21	MILLERS CREEK RET NORTH WILKESBORO NC	DIST	100.00	13.00	
22	MILLERS CREEK RET NORTH WILKESBORO NC	DIST	100.00	13.00	
23	MILLIS RET HIGH POINT NC	DIST	100.00	24.00	
24	MILLIS RET HIGH POINT NC	DIST	100.00	24.00	
25	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
26	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
27	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
28	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
29	MINE SHAFT RET CHARLOTTE NC	DIST	100.00	24.00	
30	MINE SHAFT RET CHARLOTTE NC	DIST	100.00	24.00	
31	MINE SHAFT RET CHARLOTTE NC	DIST	100.00	24.00	
32	MINI RANCH RET WAXHAW NC	DIST	100.00	24.00	
33	MITCHELL RIVER TIE ELKIN NC	TRANS	230.00	100.00	44.00
34	MITCHELL RIVER TIE ELKIN NC	TRANS	230.00	100.00	44.00
35	MITCHELL RIVER TIE ELKIN NC	TRANS	230.00	100.00	44.00
36	MITCHELL RIVER TIE ELKIN NC	TRANS	44.00		
37	MITCHELL RIVER TIE ELKIN NC	TRANS	44.00		
38	MITCHELL RIVER TIE ELKIN NC	TRANS	44.00	0.40	
39	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
40	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
2	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
3	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	44.00	
4	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	44.00	
5	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	44.00	
6	MOCKSVILLE MN MOCKSVILLE NC	TRANS	24.00	0.20	
7	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	24.00	
8	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	24.00	
9	MOCKSVILLE SOLAR	TRANS	44.00		
10	MONROE MN MONROE NC	TRANS	44.00	6.90	2.40
11	MONROE MN MONROE NC	TRANS	44.00	6.90	2.40
12	MONROE MN MONROE NC	TRANS	44.00	6.90	2.40
13	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
14	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
15	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
16	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
17	MONROE MN MONROE NC	TRANS	100.00	44.00	
18	MONROE MN MONROE NC	TRANS	100.00	44.00	
19	MONROE RD RET CHARLOTTE NC	DIST	100.00	13.00	
20	MONROE RD RET CHARLOTTE NC	DIST	100.00	13.00	
21	MONROE RD RET CHARLOTTE NC	DIST	100.00	13.00	
22	MONROETON RET MONROETON NC	DIST	44.00	13.00	
23	MONTCLAIRE RET CHARLOTTE NC	DIST	100.00	24.00	
24	MONTCLAIRE RET CHARLOTTE NC	DIST	100.00	24.00	
25	MONTICELLO RET GREENSBORO NC	DIST	44.00	13.00	
26	MONTROYAL RD RET RURAL HALL NC	DIST	100.00	13.00	
27	MOONVILLE RET GREENVILLE SC	DIST	100.00	13.00	
28	MOONVILLE RET GREENVILLE SC	DIST	100.00	13.00	
29	MOORE RET MOORE SC	DIST	44.00	13.00	
30	MOORESBORO RET MOORESBORO NC	DIST	44.00	13.00	
31	MOORESBORO RET MOORESBORO NC	DIST	44.00	13.00	
32	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
33	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
34	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
35	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
36	MOORESVILLE TIE MOORESVILLE NC	TRANS	24.00	0.20	
37	MORGANTON CITY DEL 3 MORGANTON NC	DIST	44.00	13.00	
38	MORGANTON CITY DEL 3 MORGANTON NC	DIST	44.00	13.00	
39	MORGANTON CITY DEL 4 MATS MORGANTON NC	DIST	100.00	13.00	
40	MORGANTON TIE MORGANTON NC	TRANS	100.00	24.00	13.00

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	MORGANTON TIE MORGANTON NC	TRANS	100.00	24.00	13.00
2	MORGANTON TIE MORGANTON NC	TRANS	100.00	24.00	13.00
3	MORGANTON TIE MORGANTON NC	TRANS	100.00	44.00	
4	MORGANTON TIE MORGANTON NC	TRANS	100.00	44.00	
5	MORGANTON TIE MORGANTON NC	TRANS	100.00	44.00	
6	MORGANTON TIE MORGANTON NC	TRANS			
7	MORGANTON TIE MORGANTON NC	TRANS			
8	MORNING STAR TIE MATTHEWS NC	TRANS	230.00	100.00	44.00
9	MORNING STAR TIE MATTHEWS NC	TRANS	230.00	100.00	44.00
10	MORNING STAR TIE MATTHEWS NC	TRANS	230.00	100.00	44.00
11	MORNING STAR TIE MATTHEWS NC	TRANS	100.00	24.00	
12	MORNING STAR TIE MATTHEWS NC	TRANS	100.00	24.00	
13	MORNING STAR TIE MATTHEWS NC	TRANS	44.00	0.40	
14	MOTLEY TIE EDEN NC	TRANS	100.00	44.00	
15	MOTLEY TIE EDEN NC	TRANS	100.00	44.00	
16	MOTLEY TIE EDEN NC	TRANS	24.00	0.20	
17	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
18	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
19	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
20	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
21	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
22	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
23	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
24	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
25	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
26	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
27	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
28	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
29	MT OLIVE RET CONOVER NC	DIST	44.00	13.00	
30	MT OLIVE RET CONOVER NC	DIST	44.00	13.00	
31	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
32	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
33	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
34	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
35	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
36	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
37	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	13.00	4.10
38	MT TABOR RET WINSTON-SALEM NC	DIST	100.00	13.00	
39	MT TABOR RET WINSTON-SALEM NC	DIST	100.00	13.00	
40	MTN VIEW RET HICKORY NC	DIST	100.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	MTN VIEW RET HICKORY NC	DIST	100.00	13.00	
2	MUD CREEK RD RET BOILING SPRINGS SC	DIST	100.00	13.00	
3	MUD CREEK RD RET BOILING SPRINGS SC	DIST	100.00	13.00	
4	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
5	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
6	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
7	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
8	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
9	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
10	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
11	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
12	MURDOCK RD RET TROUTMAN NC	DIST	44.00	13.00	
13	MURDOCK RD RET TROUTMAN NC	DIST	44.00	13.00	
14	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
15	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
16	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
17	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	13.00	6.90
18	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
19	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	13.00	6.90
20	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	13.00	6.90
21	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
22	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
23	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
24	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
25	N FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
26	N GORDONTON RET THOMASVILLE NC	DIST	100.00	13.00	
27	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	13.00
28	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	44.00
29	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	13.00
30	N GREENSBORO TIE GREENSBORO NC	TRANS	100.00	44.00	
31	N GREENSBORO TIE GREENSBORO NC	TRANS	44.00		
32	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	44.00
33	N GREENSBORO TIE GREENSBORO NC	TRANS	44.00	0.40	
34	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
35	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
36	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
37	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
38	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00		
39	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00		
40	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00	2.40	0.60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00	2.40	0.60
2	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00	2.40	0.60
3	N GREENWOOD RET GREENWOOD SC	DIST	44.00	13.00	
4	N GREENWOOD RET GREENWOOD SC	DIST	44.00	13.00	
5	N HICKORY RET HICKORY NC	DIST	100.00	13.00	
6	N HICKORY RET HICKORY NC	DIST	100.00	13.00	
7	N STANLEY RET STANLEY NC	DIST	100.00	13.00	4.10
8	N STANLEY RET STANLEY NC	DIST	100.00	13.00	
9	N WINSTON RET WINSTON-SALEM NC	DIST	100.00	13.00	
10	N WINSTON RET WINSTON-SALEM NC	DIST	100.00	13.00	
11	N WINSTON RET WINSTON-SALEM NC	DIST	100.00	13.00	
12	NANTAHALA HYDRO TOPTON NC	TRANS	161.00	13.00	
13	NANTAHALA HYDRO TOPTON NC	TRANS	161.00	13.00	
14	NANTAHALA HYDRO TOPTON NC	TRANS	161.00	34.50	
15	NANTAHALA HYDRO TOPTON NC	TRANS	13.00	0.40	
16	NANTAHALA HYDRO TOPTON NC	TRANS	13.00	0.40	
17	NANTAHALA HYDRO TOPTON NC	TRANS	34.50	13.00	
18	NAPLES RET NAPLES NC	DIST	44.00	13.00	
19	NAPLES RET NAPLES NC	DIST	44.00	13.00	
20	NEALS CREEK RET ANDERSON SC	DIST	44.00	13.00	
21	NEALS CREEK RET ANDERSON SC	DIST	44.00	13.00	
22	NEBO RET MARION NC	DIST	100.00	13.00	
23	NELSON RET DURHAM NC	DIST	100.00	24.00	
24	NELSON RET DURHAM NC	DIST	100.00	24.00	
25	NEW CUT RD RET INMAN SC	DIST	100.00	13.00	
26	NEW HOPE RET GASTONIA NC	DIST	100.00	13.00	
27	NEW HOPE RET GASTONIA NC	DIST	100.00	13.00	
28	NEWBERRY MN NEWBERRY SC	TRANS	100.00	24.00	
29	NEWBERRY MN NEWBERRY SC	TRANS	100.00	24.00	
30	NEWELL RET CHARLOTTE NC	DIST	100.00	24.00	
31	NEWELL RET CHARLOTTE NC	DIST	100.00	24.00	
32	NEWPORT RET NEWPORT SC	DIST	44.00	13.00	
33	NEWPORT RET NEWPORT SC	DIST	44.00	13.00	
34	NEWPORT TIE NEWPORT SC	TRANS	230.00	100.00	44.00
35	NEWPORT TIE NEWPORT SC	TRANS	230.00	100.00	44.00
36	NEWPORT TIE NEWPORT SC	TRANS	230.00	100.00	44.00
37	NEWPORT TIE NEWPORT SC	TRANS	44.00	0.40	
38	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
39	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
40	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
2	NEWPORT TIE NEWPORT SC	TRANS	44.00		
3	NEWPORT TIE NEWPORT SC	TRANS	500.00		
4	NEWPORT TIE NEWPORT SC	TRANS	500.00		
5	NEWPORT TIE NEWPORT SC	TRANS	500.00		
6	NEWTON CITY DEL 2 NEWTON NC	DIST	100.00	13.00	6.90
7	NEWTON CITY DEL 2 NEWTON NC	DIST	100.00	13.00	6.90
8	NEWTON CITY DEL 2 NEWTON NC	DIST	100.00	13.00	6.90
9	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
10	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
11	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
12	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
13	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
14	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
15	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
16	NEWTON TIE NEWTON NC	TRANS	24.00	0.20	
17	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
18	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
19	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
20	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
21	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
22	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
23	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
24	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
25	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
26	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
27	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	24.00	0.20	
28	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	24.00	0.20	
29	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	24.00	0.20	
30	NIX RD RET HENDERSONVILLE NC	DIST	100.00	13.00	
31	NORRIS RET CATEECHEE SC	DIST	44.00	13.00	
32	NORRIS RET CATEECHEE SC	DIST	44.00	13.00	
33	NORTH DENVER RET DENVER NC	DIST	100.00	13.00	
34	NORTH LAKES RET HICKORY NC	DIST	100.00	13.00	
35	NORTH LINCOLN RET LINCOLNTON NC	DIST	44.00	13.00	
36	NORTH ST RET ANDERSON SC	DIST	44.00	13.00	
37	OAK GROVE RET SHELBY NC	DIST	44.00	13.00	8.00
38	OAK GROVE RET SHELBY NC	DIST	44.00	13.00	
39	OAK RIDGE RET KERNERSVILLE NC	DIST	100.00	13.00	
40	OAK RIDGE RET KERNERSVILLE NC	DIST	100.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
2	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
3	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
4	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
5	OAKBORO TIE OAKBORO NC	TRANS	230.00	100.00	44.00
6	OAKBORO TIE OAKBORO NC	TRANS	230.00	100.00	44.00
7	OAKBORO TIE OAKBORO NC	TRANS	230.00	100.00	44.00
8	OAKBORO TIE OAKBORO NC	TRANS	44.00		
9	OAKBORO TIE OAKBORO NC	TRANS	44.00	0.40	
10	OAKLAND RD RET SPINDALE NC	DIST	100.00	13.00	
11	OAKLAND RD RET SPINDALE NC	DIST	100.00	13.00	
12	OAKVALE TIE GREENVILLE SC	TRANS	100.00	24.00	
13	OAKVALE TIE GREENVILLE SC	TRANS	100.00	24.00	
14	OAKVALE TIE GREENVILLE SC	TRANS	100.00	24.00	
15	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
16	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
17	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
18	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	24.00
19	OAKVALE TIE GREENVILLE SC	TRANS	100.00	13.00	
20	OAKVALE TIE GREENVILLE SC	TRANS	100.00	13.00	
21	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
22	OAKWOOD ST RET MEBANE NC	DIST	100.00	13.00	
23	OAKWOOD ST RET MEBANE NC	DIST	100.00	13.00	
24	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	230.00	4.10	
25	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	24.00	4.10	
26	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
27	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
28	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
29	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
30	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
31	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
32	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
33	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
34	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
35	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
36	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
37	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
38	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
39	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
40	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	230.00	24.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	24.00	6.90	4.10
2	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
3	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
4	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
5	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
6	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
7	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
8	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
9	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
10	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
11	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
12	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
13	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	230.00	6.90	4.10
14	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	230.00	6.90	4.10
15	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
16	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
17	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	230.00	24.00	
18	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	24.00	6.90	4.10
19	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
20	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
21	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
22	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
23	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
24	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
25	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
26	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
27	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
28	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
29	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	230.00	6.90	4.10
30	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
31	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
32	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
33	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
34	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	24.00	6.90	4.10
35	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
36	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
37	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
38	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
39	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
40	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
2	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
3	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
4	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	230.00	6.90	4.10
5	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	13.00	4.10	
6	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	13.00	4.10	
7	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	100.00	4.10	4.10
8	OCONEE SITE 100KV NEWRY SC	TRANS	100.00	24.00	
9	OCONEE SITE 100KV NEWRY SC	TRANS	100.00	24.00	
10	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
11	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
12	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
13	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
14	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
15	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
16	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
17	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
18	OLD FORT RET OLD FORT NC	DIST	44.00	13.00	
19	ONEAL RET GREER SC	DIST	100.00	13.00	
20	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
21	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
22	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
23	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
24	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	
25	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	
26	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	
27	OTTO RET OTTO NC	DIST	69.00	13.00	
28	OXFORD HYDRO CONOVER NC	TRANS	100.00	6.90	
29	OXFORD HYDRO CONOVER NC	TRANS	100.00	6.90	
30	OXFORD RD RET DURHAM NC	DIST	100.00	13.00	
31	OXFORD RD RET DURHAM NC	DIST	100.00	13.00	
32	OYAMA RET HICKORY NC	DIST	100.00	13.00	
33	OYAMA RET HICKORY NC	DIST	100.00	13.00	
34	PACOLET RET PACOLET SC	DIST	44.00	6.90	
35	PACOLET RET PACOLET SC	DIST	44.00	6.90	
36	PACOLET RET PACOLET SC	DIST	44.00	6.90	
37	PACOLET RET PACOLET SC	DIST	44.00	6.90	
38	PACOLET TIE PACOLET SC	TRANS	230.00	100.00	13.00
39	PACOLET TIE PACOLET SC	TRANS	230.00	100.00	44.00
40	PACOLET TIE PACOLET SC	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) ☐ An Original (2) ☒ A Resubmission	05/29/2019	End of 2018/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	PANORAMA RET GREENWOOD SC	DIST	44.00	13.00	
2	PANORAMA RET GREENWOOD SC	DIST	44.00	13.00	
3	PARADISE RET FOREST CITY NC	DIST	44.00	13.00	
4	PARK RD RET CHARLOTTE NC	DIST	100.00	13.00	
5	PARK RD RET CHARLOTTE NC	DIST	100.00	13.00	
6	PARK RD RET CHARLOTTE NC	DIST	100.00	13.00	
7	PARKWAY SS GROVER NC	DIST	100.00	13.00	
8	PARKWAY SS GROVER NC	DIST	100.00	13.00	
9	PARKWOOD RET DURHAM NC	DIST	100.00	24.00	
10	PARKWOOD TIE DURHAM NC	TRANS	230.00	100.00	44.00
11	PARKWOOD TIE DURHAM NC	TRANS	230.00	100.00	44.00
12	PARKWOOD TIE DURHAM NC	TRANS	230.00	100.00	44.00
13	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
14	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
15	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
16	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
17	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
18	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
19	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
20	PARKWOOD TIE DURHAM NC	TRANS	44.00	0.40	
21	PARKWOOD TIE DURHAM NC	TRANS	13.00	0.40	
22	PATTERSON SPRINGS RET SHELBY NC	DIST	100.00	13.00	
23	PATTERSON SPRINGS RET SHELBY NC	DIST	100.00	13.00	
24	PEACE HAVEN RD RET CLEMMONS NC	DIST	100.00	13.00	
25	PEACE HAVEN RD RET CLEMMONS NC	DIST	100.00	13.00	
26	PEACH VALLEY TIE SPARTANBURG SC	TRANS	230.00	100.00	44.00
27	PEACH VALLEY TIE SPARTANBURG SC	TRANS	230.00	100.00	44.00
28	PEACH VALLEY TIE SPARTANBURG SC	TRANS	230.00	100.00	44.00
29	PEACH VALLEY TIE SPARTANBURG SC	TRANS	44.00		
30	PEACH VALLEY TIE SPARTANBURG SC	TRANS	44.00		
31	PEACH VALLEY TIE SPARTANBURG SC	TRANS	44.00	0.40	
32	PEACOCK TIE GASTONIA NC	TRANS	230.00	100.00	44.00
33	PEACOCK TIE GASTONIA NC	TRANS	230.00	100.00	44.00
34	PEACOCK TIE GASTONIA NC	TRANS	100.00	13.00	
35	PEACOCK TIE GASTONIA NC	TRANS	44.00		
36	PEACOCK TIE GASTONIA NC	TRANS	44.00	0.40	
37	PEACOCK TIE GASTONIA NC	TRANS	44.00		
38	PEARMAN SS ANDERSON SC	DIST	100.00	13.00	
39	PEARMAN SS ANDERSON SC	DIST	100.00	13.00	
40	PEBBLE CREEK RET GREENVILLE SC	DIST	100.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	PEBBLE CREEK RET GREENVILLE SC	DIST	100.00	13.00	
2	PEELER RET GAFFNEY SC	DIST	44.00	13.00	
3	PEELER RET GAFFNEY SC	DIST	44.00	13.00	
4	PELHAM RET TAYLORS SC	DIST	100.00	24.00	
5	PELHAM RET TAYLORS SC	DIST	100.00	24.00	
6	PELZER RET PELZER SC	DIST	44.00	13.00	
7	PENDLETON RET PENDLETON SC	DIST	44.00	2.40	
8	PENDLETON RET PENDLETON SC	DIST	44.00	2.40	
9	PENDLETON RET PENDLETON SC	DIST	44.00	2.40	
10	PENDLETON RET PENDLETON SC	DIST	44.00	6.90	2.40
11	PENDLETON RET PENDLETON SC	DIST	44.00	13.00	
12	PERTH RD RET TROUTMAN NC	DIST	44.00	24.00	
13	PERTH RD RET TROUTMAN NC	DIST	44.00	13.00	
14	PETERS CREEK RET SPARTANBURG SC	DIST	44.00	13.00	
15	PFAFFTOWN RET WINSTON-SALEM NC	DIST	100.00	13.00	
16	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
17	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
18	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
19	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
20	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
21	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
22	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
23	PICKENS TIE PICKENS SC	TRANS	100.00	44.00	
24	PICKENS TIE PICKENS SC	TRANS	100.00	44.00	
25	PICKENS TIE PICKENS SC	TRANS	100.00	44.00	
26	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
27	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
28	PIEDMONT RET PIEDMONT SC	DIST	44.00	13.00	6.90
29	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
30	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
31	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
32	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
33	PIEDMONT RET PIEDMONT SC	DIST	13.00	2.40	
34	PIERCETOWN SS ANDERSON SC	DIST	100.00	13.00	
35	PIERCETOWN SS ANDERSON SC	DIST	100.00	13.00	
36	PINCH GUT CREEK RET NEWTON NC	DIST	100.00	13.00	
37	PINEVILLE CITY DEL 2 PINEVILLE NC	DIST	100.00	13.00	
38	PINEWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
39	PINEWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
40	PINK HARRILL TIE CAROLEEN NC	TRANS	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	PINK HARRILL TIE CAROLEEN NC	TRANS	100.00	44.00	
2	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
3	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
4	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
5	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
6	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
7	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
8	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
9	PINNACLE TIE PINNACLE NC	TRANS	24.00	0.20	
10	PIONEER AVE RET CHARLOTTE NC	DIST	100.00	24.00	
11	PIONEER AVE RET CHARLOTTE NC	DIST	100.00	24.00	
12	PIPER GLEN RET CHARLOTTE NC	DIST	100.00	24.00	
13	PIPER GLEN RET CHARLOTTE NC	DIST	100.00	24.00	
14	PIPER GLEN RET CHARLOTTE NC	DIST	100.00	24.00	
15	PISGAH TIE PISGAH FOREST NC	TRANS	230.00	100.00	44.00
16	PISGAH TIE PISGAH FOREST NC	TRANS	230.00	100.00	44.00
17	PISGAH TIE PISGAH FOREST NC	TRANS	100.00	44.00	
18	PISGAH TIE PISGAH FOREST NC	TRANS	100.00	100.00	13.00
19	PISGAH TIE PISGAH FOREST NC	TRANS	100.00	100.00	13.00
20	PISGAH TIE PISGAH FOREST NC	TRANS	44.00		
21	PISGAH TIE PISGAH FOREST NC	TRANS	44.00		
22	PISGAH TIE PISGAH FOREST NC	TRANS	44.00	0.40	
23	PITTS SCHOOL RET CONCORD NC	DIST	100.00	13.00	
24	PLAINVIEW RET ANDERSON SC	DIST	100.00	13.00	
25	PLAINVIEW RET ANDERSON SC	DIST	100.00	13.00	
26	PLEASANT GARDEN RET PLEASANT GARDEN NC	DIST	44.00	13.00	
27	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	230.00	100.00	44.00
28	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	230.00	100.00	44.00
29	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	230.00	100.00	44.00
30	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
31	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
32	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
33	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
34	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	44.00		
35	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00		
36	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00		
37	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00		
38	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00		
39	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	44.00	0.40	
40	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	24.00	0.40	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	POPE RD RET DURHAM NC	DIST	100.00	24.00	
2	POPE RD RET DURHAM NC	DIST	100.00	24.00	
3	POPLAR TENT RET CONCORD NC	DIST	100.00	13.00	
4	POPLAR TENT RET CONCORD NC	DIST	100.00	13.00	
5	PORTER RANCH RET VAN WYCK SC	DIST	446.90	2.40	
6	PORTER RANCH RET VAN WYCK SC	DIST	44.00	6.90	2.40
7	PORTER RANCH RET VAN WYCK SC	DIST	44.00	13.00	
8	PORTER RANCH RET VAN WYCK SC	DIST	44.00	6.90	2.40
9	PORTER RANCH RET VAN WYCK SC	DIST	44.00	6.90	2.40
10	POWDERSVILLE RET POWDERSVILLE SC	DIST	44.00	13.00	
11	POWDERSVILLE RET POWDERSVILLE SC	DIST	44.00	13.00	
12	PROCTER & GAMBLE GBORO PL T&D GREENSBORO NC	DIST	44.00	13.00	
13	PROPST RET HICKORY NC	DIST	44.00	13.00	
14	PROPST RET HICKORY NC	DIST	44.00	13.00	
15	PROVOL RET CHARLOTTE NC	DIST	100.00	24.00	
16	PROVOL RET CHARLOTTE NC	DIST	100.00	24.00	
17	PROVOL RET CHARLOTTE NC	DIST	100.00	24.00	
18	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	13.00	
19	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	13.00	
20	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	24.00	
21	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	24.00	
22	RAGSDALE RET JAMESTOWN NC	DIST	100.00	24.00	
23	RAGSDALE RET JAMESTOWN NC	DIST	100.00	24.00	
24	RANDLEMAN RD RET RANDLEMAN NC	DIST	100.00	13.00	4.10
25	RANDLEMAN RD RET RANDLEMAN NC	DIST	100.00	13.00	
26	RANDOLPH AVE RET GREENSBORO NC	DIST	100.00	24.00	
27	RANDOLPH AVE RET GREENSBORO NC	DIST	100.00	24.00	
28	RANDOLPH AVE RET GREENSBORO NC	DIST	100.00	24.00	
29	RANKIN AVE RET MOUNT HOLLY NC	DIST	100.00	13.00	
30	RANKIN AVE RET MOUNT HOLLY NC	DIST	100.00	13.00	
31	REAMES RD RET CHARLOTTE NC	DIST	100.00	24.00	
32	REAMES RD RET CHARLOTTE NC	DIST	100.00	24.00	
33	REAMES RD RET CHARLOTTE NC	DIST	100.00	24.00	
34	RED RAIDER RET BELMONT NC	DIST	100.00	13.00	
35	RED ROSE RET LANCASTER SC	DIST	100.00	13.00	
36	RED ROSE RET LANCASTER SC	DIST	100.00	13.00	
37	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
38	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
39	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
40	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	44.00	24.00
2	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	44.00	24.00
3	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	44.00	24.00
4	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	
5	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	
6	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	4.10
7	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	4.10
8	REMOUNT RD RET CHARLOTTE NC	DIST	100.00	13.00	
9	REMOUNT RD RET CHARLOTTE NC	DIST	100.00	13.00	
10	RESEARCH TRIANGLE RET DURHAM NC	DIST	100.00	24.00	
11	RESEARCH TRIANGLE RET DURHAM NC	DIST	100.00	24.00	
12	RESEARCH TRIANGLE RET DURHAM NC	DIST	100.00	24.00	
13	RHODHISS HYDRO PL RHODHISS NC	TRANS	46.00	6.60	
14	RHODHISS HYDRO PL RHODHISS NC	TRANS	46.00	6.60	
15	RHODHISS HYDRO PL RHODHISS NC	TRANS	46.00	6.60	
16	RHODHISS TIE RHODHISS NC	TRANS	100.00	44.00	
17	RHODHISS TIE RHODHISS NC	TRANS	100.00	44.00	
18	RHODHISS TIE RHODHISS NC	TRANS	44.00	0.24	
19	RICH MOUNTAIN RET BREVARD NC	DIST	100.00	13.00	
20	RICH MOUNTAIN RET BREVARD NC	DIST	100.00	13.00	
21	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
22	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
23	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
24	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
25	RIDGEVIEW RET EDEN NC	DIST	100.00	13.00	
26	RIDGEVIEW RET EDEN NC	DIST	100.00	13.00	
27	RIVER HILLS RET CLOVER SC	DIST	100.00	24.00	
28	RIVER HILLS RET CLOVER SC	DIST	100.00	24.00	
29	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	230.00	100.00	44.00
30	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	230.00	100.00	44.00
31	RIVERSTONE RET FOREST CITY NC	DIST	100.00	13.00	
32	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
33	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
34	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
35	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
36	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00	34.50	
37	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
38	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
39	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
40	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		

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	ROBERTA RD RET CONCORD NC	DIST	44.00	13.00	
2	ROBERTA RD RET CONCORD NC	DIST	44.00	13.00	
3	ROCHESTER TIE NEWRY SC	TRANS	100.00	44.00	
4	ROCK HILL CITY DEL 4 ROCK HILL SC	DIST	100.00	24.00	13.00
5	ROCK HILL CITY DEL 4 ROCK HILL SC	DIST	100.00	24.00	13.00
6	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
7	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
8	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
9	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
10	ROCKETT RET CONOVER NC	DIST	100.00	13.00	
11	ROCKETT RET CONOVER NC	DIST	100.00	13.00	
12	ROCKWELL RET ROCKWELL NC	DIST	100.00	13.00	
13	ROCKWELL RET ROCKWELL NC	DIST	100.00	13.00	
14	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
15	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
16	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
17	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
18	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	2.40	0.40	
19	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	2.40	0.40	
20	ROPER MTN RET GREENVILLE SC	DIST	100.00	13.00	
21	ROPER MTN RET GREENVILLE SC	DIST	100.00	13.00	
22	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
23	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
24	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
25	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
26	ROSMAN SS ROSMAN NC	DIST	44.00	6.90	2.40
27	ROSMAN SS ROSMAN NC	DIST	44.00	6.90	2.40
28	ROSMAN SS ROSMAN NC	DIST	44.00	13.00	6.90
29	ROSMAN SS ROSMAN NC	DIST	44.00	13.00	6.90
30	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	44.00	13.00	
31	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
32	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
33	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
34	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
35	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
36	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
37	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
38	ROYAL RET CHARLOTTE NC	DIST	100.00	24.00	
39	ROYAL RET CHARLOTTE NC	DIST	100.00	24.00	
40	ROZZELLES RET CHARLOTTE NC	DIST	100.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	ROZZELLES RET CHARLOTTE NC	DIST	100.00	13.00	
2	RUDD RET GREENSBORO NC	DIST	100.00	24.00	
3	RUDD RET GREENSBORO NC	DIST	100.00	24.00	
4	RUFFIN RET RUFFIN NC	DIST	44.00	13.00	
5	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
6	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
7	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
8	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
9	RURAL HALL RET RURAL HALL NC	DIST	44.00	13.00	
10	RURAL HALL RET RURAL HALL NC	DIST	44.00	13.00	
11	RURAL HALL TIE RURAL HALL NC	TRANS	230.00	100.00	44.00
12	RURAL HALL TIE RURAL HALL NC	TRANS	230.00	100.00	44.00
13	RURAL HALL TIE RURAL HALL NC	TRANS	230.00	100.00	44.00
14	RURAL HALL TIE RURAL HALL NC	TRANS	44.00	0.40	
15	RURAL HALL TIE RURAL HALL NC	TRANS	44.00		
16	RUTHERFORD COLLEGE RET RUTHERFORD COLLEGE	DIST	44.00	24.00	13.00
17	RUTHERFORD COLLEGE RET RUTHERFORD COLLEGE	DIST	44.00	13.00	
18	RUTLEDGE TIE MT AIRY NC	TRANS	100.00	44.00	
19	RUTLEDGE TIE MT AIRY NC	TRANS	100.00	44.00	
20	S CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	
21	S CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	
22	S FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
23	S FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
24	S GASTONIA RET GASTONIA NC	DIST	44.00	13.00	
25	S GASTONIA RET GASTONIA NC	DIST	44.00	13.00	
26	S HICKORY RET HICKORY NC	DIST	100.00	13.00	
27	S HICKORY RET HICKORY NC	DIST	100.00	13.00	
28	S SHELBY SS SHELBY NC	DIST	44.00	13.00	
29	S SYLVA RET SYLVA NC	DIST	67.00	13.20	
30	SADLER TIE REIDSVILLE NC	TRANS	230.00	100.00	44.00
31	SADLER TIE REIDSVILLE NC	TRANS	230.00	100.00	44.00
32	SADLER TIE REIDSVILLE NC	TRANS	44.00		
33	SADLER TIE REIDSVILLE NC	TRANS	44.00	0.40	
34	SALISBURY MN SALISBURY NC	TRANS	100.00	13.00	
35	SALISBURY MN SALISBURY NC	TRANS	100.00	13.00	
36	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	
37	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	
38	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	
39	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
40	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
2	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
3	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
4	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
5	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
6	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
7	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
8	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
9	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
10	SALISBURY MN SALISBURY NC	TRANS	24.00	0.20	
11	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
12	SALUDA RET SALUDA NC	DIST	44.00	6.90	
13	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
14	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
15	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
16	SALUDA RET SALUDA NC	DIST	44.00	6.90	
17	SALUDA RET SALUDA NC	DIST	44.00	6.90	
18	SANDS RD RET REIDSVILLE NC	DIST	100.00	24.00	
19	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
20	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
21	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
22	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
23	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	6.90	2.40
24	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	6.90	2.40
25	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	6.90	2.40
26	SANDY SPRINGS TIE SANDY SPRINGS SC	TRANS	100.00	44.00	
27	SANDY SPRINGS TIE SANDY SPRINGS SC	TRANS	100.00	44.00	
28	SANDY SPRINGS TIE SANDY SPRINGS SC	TRANS	24.00	0.20	
29	SAPPHIRE RET CASHIERS NC	DIST	66.00	13.00	
30	SAWMILLS RET SAWMILLS NC	DIST	44.00	13.00	
31	SAWMILLS RET SAWMILLS NC	DIST	44.00	13.00	
32	SAXAPAHAW RET SAXAPAHAW NC	DIST	44.00	13.00	
33	SAXAPAHAW RET SAXAPAHAW NC	DIST	44.00	13.00	
34	SCUFFLETOWN RET SIMPSONVILLE SC	DIST	100.00	13.00	
35	SEDGE GARDEN RET KERNERSVILLE NC	DIST	100.00	13.00	
36	SEDGE GARDEN RET KERNERSVILLE NC	DIST	100.00	13.00	
37	SEDGE GARDEN RET KERNERSVILLE NC	DIST	100.00	24.00	
38	SENECA CITY DEL 1 SENECA SC	DIST	100.00	13.00	
39	SENECA CITY DEL 2 SENECA SC	DIST	100.00	13.00	
40	SENECA TIE SENECA SC	TRANS	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	SENECA TIE SENECA SC	TRANS	100.00	44.00	
2	SEVENTH ST RET BURLINGTON NC	DIST	100.00	24.00	
3	SEVENTH ST RET BURLINGTON NC	DIST	100.00	24.00	
4	SEVENTH ST RET BURLINGTON NC	DIST	24.00	6.90	2.40
5	SEVENTH ST RET BURLINGTON NC	DIST	24.00	6.90	2.40
6	SEVENTH ST RET BURLINGTON NC	DIST	24.00	6.90	2.40
7	SEVENTH ST RET BURLINGTON NC	DIST	24.00	2.40	
8	SEWARD RET WINSTON-SALEM NC	DIST	100.00	24.00	
9	SEWARD RET WINSTON-SALEM NC	DIST	100.00	24.00	
10	SHACKTOWN RET YADKINVILLE NC	DIST	100.00	13.00	
11	SHADY GROVE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
12	SHADY GROVE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
13	SHADY GROVE TIE GREENVILLE SC	TRANS	44.00		
14	SHADY GROVE TIE GREENVILLE SC	TRANS	44.00		
15	SHADY GROVE TIE GREENVILLE SC	TRANS	44.00	0.40	
16	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
17	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
18	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
19	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
20	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
21	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
22	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
23	SHARON RET CHARLOTTE NC	DIST	100.00	24.00	
24	SHARON RET CHARLOTTE NC	DIST	100.00	24.00	
25	SHATTALON SW STA WINSTON-SALEM NC	TRANS	100.00	13.00	
26	SHATTALON SW STA WINSTON-SALEM NC	TRANS	100.00	13.00	
27	SHELBY CITY DEL 8 SHELBY NC	DIST	44.00	13.00	
28	SHELBY CITY DEL 8 SHELBY NC	DIST	44.00	13.00	
29	SHELBY MN SHELBY NC	DIST	44.00	2.40	
30	SHELBY MN SHELBY NC	DIST	44.00	2.40	
31	SHELBY MN SHELBY NC	DIST	44.00	2.40	
32	SHELBY MN SHELBY NC	DIST	44.00	2.40	
33	SHELBY TIE SHELBY NC	TRANS	230.00	100.00	44.00
34	SHELBY TIE SHELBY NC	TRANS	230.00	100.00	44.00
35	SHELBY TIE SHELBY NC	TRANS	230.00	100.00	44.00
36	SHELBY TIE SHELBY NC	TRANS	44.00		
37	SHELBY TIE SHELBY NC	TRANS	44.00		
38	SHELBY TIE SHELBY NC	TRANS	44.00	2.40	0.60
39	SHELBY TIE SHELBY NC	TRANS	44.00	2.40	0.60
40	SHELBY TIE SHELBY NC	TRANS	44.00	2.40	0.60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	SHERRILLS FORD SS SHERRILLS FORD NC	DIST	44.00	13.00	
2	SHERRILLS FORD SS SHERRILLS FORD NC	DIST	44.00	13.00	
3	SHOPTON RET CHARLOTTE NC	DIST	100.00	24.00	
4	SHORTOFF RET HIGHLANDS NC	DIST	66.00	13.00	
5	SIX MILE RET SIX MILE SC	DIST	44.00	13.00	
6	SMITHTOWN RET SMITHTOWN NC	DIST	44.00	13.00	
7	SOUTHBOUND RET WINSTON-SALEM NC	DIST	100.00	24.00	
8	SOUTHBOUND RET WINSTON-SALEM NC	DIST	100.00	24.00	
9	SOUTHBOUND RET WINSTON-SALEM NC	DIST	100.00	13.00	
10	SOUTHPORT RD RET SPARTANBURG SC	DIST	100.00	13.00	
11	SPARTAN GREEN RET DUNCAN SC	DIST	100.00	24.00	
12	SPARTAN GREEN RET DUNCAN SC	DIST	100.00	24.00	
13	SPARTAN HEIGHTS RET HENDERSONVILLE NC	DIST	44.00	13.00	
14	SPARTAN HEIGHTS RET HENDERSONVILLE NC	DIST	44.00	13.00	
15	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
16	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
17	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
18	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
19	SPEEDWAY RET HARRISBURG NC	DIST	100.00	24.00	
20	SPEEDWAY RET HARRISBURG NC	DIST	13.00		
21	SPRINGFIELD RET CHARLOTTE NC	DIST	100.00	24.00	
22	SPRINGFIELD RET CHARLOTTE NC	DIST	100.00	24.00	
23	SPRINGS IND SS FORT LAWN SC	DIST	100.00	24.00	13.00
24	SPRINGS IND SS FORT LAWN SC	DIST	13.00		
25	ST MARKS RET BURLINGTON NC	DIST	100.00	24.00	
26	ST MARKS RET BURLINGTON NC	DIST	100.00	24.00	
27	ST STEPHENS RET HICKORY NC	DIST	100.00	13.00	
28	ST STEPHENS RET HICKORY NC	DIST	100.00	13.00	
29	STALLINGS RD RET DURHAM NC	DIST	100.00	13.00	
30	STALLINGS RD RET DURHAM NC	DIST	100.00	24.00	
31	STAMEY TIE STATESVILLE NC	TRANS	230.00	100.00	13.00
32	STAMEY TIE STATESVILLE NC	TRANS	230.00	100.00	13.00
33	STAMEY TIE STATESVILLE NC	TRANS	230.00	100.00	44.00
34	STAMEY TIE STATESVILLE NC	TRANS	13.00	0.40	
35	STAMEY TIE STATESVILLE NC	TRANS	13.00	0.40	
36	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
37	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
38	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
39	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
40	STARTOWN RET NEWTON 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	STARTOWN RET NEWTON NC	DIST	44.00	13.00	
2	STATESVILLE CITY DEL 2 STATESVILLE NC	DIST	100.00	24.00	
3	STATESVILLE CITY DEL 2 STATESVILLE NC	DIST	100.00	24.00	13.00
4	STATESVILLE CITY DEL 3 STATESVILLE NC	DIST	100.00	24.00	
5	STATESVILLE RD RET SALISBURY NC	DIST	100.00	13.00	
6	STATESVILLE RD RET SALISBURY NC	DIST	100.00	13.00	
7	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	44.00	
8	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	44.00	
9	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	44.00	
10	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
11	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
12	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
13	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
14	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
15	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
16	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
17	STEELE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
18	STEELE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
19	STOUTS RET STOUTS NC	DIST	100.00	24.00	
20	STOUTS RET STOUTS NC	DIST	100.00	24.00	
21	STOUTS RET STOUTS NC	DIST	100.00	24.00	
22	SUGAR HILL TIE MARION NC	TRANS	100.00	44.00	
23	SUGAR HILL TIE MARION NC	TRANS	100.00	44.00	
24	SUGAR HILL TIE MARION NC	TRANS	24.00	0.20	
25	SUMMERFIELD RET SUMMERFIELD NC	DIST	100.00	24.00	
26	SUMMERFIELD RET SUMMERFIELD NC	DIST	100.00	24.00	
27	SUMMEY ST RET CLEMSON SC	DIST	100.00	13.00	
28	SUMMEY ST RET CLEMSON SC	DIST	100.00	13.00	
29	SUMMEY ST RET CLEMSON SC	DIST	100.00	13.00	
30	SUMNER RET SALISBURY NC	DIST	100.00	13.00	
31	SUMNER RET SALISBURY NC	DIST	100.00	13.00	
32	SUN CITY YORK SC	DIST	100.00	24.00	
33	SUNSET RET CHARLOTTE NC	DIST	100.00	13.00	
34	SUNSET RET CHARLOTTE NC	DIST	100.00	13.00	
35	SWAIMTOWN RET WINSTON-SALEM NC	DIST	100.00	13.00	
36	SWAIMTOWN RET WINSTON-SALEM NC	DIST	100.00	13.00	
37	SWAIN TIE BRYSON CITY NC	TRANS	161.00	66.00	
38	SWAIN TIE BRYSON CITY NC	TRANS	161.00	66.00	
39	SWAIN TIE BRYSON CITY NC	TRANS	170.00	66.00	
40	SWAIN TIE BRYSON CITY NC	TRANS	69.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	SWAIN TIE BRYSON CITY NC	TRANS	69.00	13.00	
2	SWEETWATER RET HICKORY NC	DIST	100.00	13.00	
3	SWEETWATER RET HICKORY NC	DIST	100.00	13.00	
4	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	100.00	44.00	
5	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	100.00	44.00	
6	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	44.00	13.00	
7	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	44.00	13.00	
8	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	24.00	0.20	
9	TABERNACLE CHURCH RET GREENSBORO NC	DIST	44.00	13.00	
10	TABLE ROCK TIE MORGANTON NC	TRANS	100.00	44.00	33.00
11	TABLE ROCK TIE MORGANTON NC	TRANS	100.00	44.00	
12	TABLE ROCK TIE MORGANTON NC	TRANS	100.00	44.00	33.00
13	TABLE ROCK TIE MORGANTON NC	TRANS	44.00		
14	TABLE ROCK TIE MORGANTON NC	TRANS	24.00	0.20	
15	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
16	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
17	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
18	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
19	TARRANT RD RET GREENSBORO NC	DIST	100.00	24.00	
20	TARRANT RD RET GREENSBORO NC	DIST	100.00	24.00	
21	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	44.00	
22	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	44.00	
23	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
24	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
25	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
26	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	24.00	0.20	
27	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
28	TECHNOLOGY RET CHARLOTTE NC	DIST	100.00	24.00	
29	TECHNOLOGY RET CHARLOTTE NC	DIST	100.00	24.00	
30	TEGA CAY RET FORT MILL SC	DIST	100.00	24.00	
31	TEGA CAY RET FORT MILL SC	DIST	100.00	24.00	13.00
32	TENNESSEE CREEK HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
33	THIRD AVE RET HICKORY NC	DIST	100.00	13.00	
34	THIRD AVE RET HICKORY NC	DIST	100.00	13.00	
35	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
36	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
37	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
38	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
39	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
40	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
2	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
3	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
4	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
5	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
6	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
7	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	66.00	
8	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	66.00	
9	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	13.00	
10	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
11	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
12	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
13	THORPE HYDRO TUCKASEGEE NC	TRANS	6.90		
14	THRIFT RET CHARLOTTE NC	DIST	100.00	13.00	
15	THRIFT RET CHARLOTTE NC	DIST	100.00	13.00	
16	TIGER TIE DUNCAN SC	TRANS	230.00	100.00	44.00
17	TIGER TIE DUNCAN SC	TRANS	230.00	100.00	44.00
18	TIGER TIE DUNCAN SC	TRANS	230.00	100.00	44.00
19	TIGER TIE DUNCAN SC	TRANS	44.00		
20	TIGER TIE DUNCAN SC	TRANS	44.00		
21	TIGER TIE DUNCAN SC	TRANS	44.00	0.40	
22	TIGER TIE DUNCAN SC	TRANS	44.00	0.40	
23	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
24	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
25	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
26	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
27	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
28	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
29	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
30	TNS M GREEN PL STA 3 GREER SC	DIST	100.00	13.00	
31	TOAST RET TOAST NC	DIST	100.00	13.00	
32	TOAST RET TOAST NC	DIST	100.00	13.00	
33	TOXAWAY TIE ANDERSON SC	TRANS	100.00	44.00	24.00
34	TOXAWAY TIE ANDERSON SC	TRANS	100.00	44.00	24.00
35	TOXAWAY TIE ANDERSON SC	TRANS	100.00	13.00	
36	TOXAWAY TIE ANDERSON SC	TRANS	100.00	13.00	
37	TOXAWAY TIE ANDERSON SC	TRANS	100.00	13.00	
38	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
39	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
40	TOXAWAY TIE ANDERSON SC	TRANS	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
2	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
3	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
4	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
5	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
6	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
7	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
8	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
9	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
10	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
11	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
12	TREMONT RET LENOIR NC	DIST	44.00	13.00	
13	TREMONT RET LENOIR NC	DIST	44.00	13.00	
14	TREYBURN RET DURHAM NC	DIST	100.00	24.00	
15	TREYBURN RET DURHAM NC	DIST	100.00	24.00	
16	TRIAD PARK RET KERNERSVILLE NC	DIST	100.00	13.00	
17	TRIAD PARK RET KERNERSVILLE NC	DIST	100.00	13.00	
18	TRIANGLE RET LOWESVILLE NC	DIST	100.00	24.00	
19	TRIANGLE RET LOWESVILLE NC	DIST	100.00	13.00	4.10
20	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
21	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
22	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
23	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
24	TRIBBLE ST RET ANDERSON SC	DIST	44.00	2.40	0.60
25	TRIBBLE ST RET ANDERSON SC	DIST	44.00	2.40	0.60
26	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
27	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
28	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
29	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
30	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
31	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
32	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
33	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
34	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
35	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
36	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	
37	TRIPLETT RET MOORESVILLE NC	DIST	100.00	13.00	
38	TRIPLETT RET MOORESVILLE NC	DIST	100.00	13.00	6.90
39	TROLLINGWOOD RET HAW RIVER NC	DIST	100.00	24.00	
40	TROLLINGWOOD RET HAW RIVER NC	DIST	100.00	24.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
2	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
3	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
4	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
5	TROUTMAN RET TROUTMAN NC	DIST	44.00	13.00	6.90
6	TROUTMAN RET TROUTMAN NC	DIST	44.00	13.00	6.90
7	TROUTMAN RET TROUTMAN NC	DIST	44.00	13.00	6.90
8	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
9	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
10	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
11	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
12	TRYON RET TRYON NC	DIST	44.00	13.00	
13	TRYON RET TRYON NC	DIST	44.00	13.00	
14	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	230.00	161.00	13.00
15	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	230.00	161.00	13.00
16	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	13.00	0.40	
17	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	13.00	0.40	
18	TUCKERS CREEK RET BREVARD NC	DIST	44.00	13.00	
19	TUCKERS CREEK RET BREVARD NC	DIST	44.00	13.00	
20	TUMBLING SHOALS SS LAURENS SC	DIST	44.00	6.90	
21	TUMBLING SHOALS SS LAURENS SC	DIST	44.00	6.90	
22	TUMBLING SHOALS SS LAURENS SC	DIST	44.00	6.90	2.40
23	TUMBLING SHOALS SS LAURENS SC	DIST	44.00	6.90	2.40
24	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00	2.40	0.60
25	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00	2.40	0.60
26	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00	2.40	0.60
27	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00		
28	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	2.40		
29	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	2.40		
30	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	24.00	0.20	
31	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	6.90	
32	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	6.90	
33	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	6.90	
34	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	24.00	6.90
35	TYSINGER RD RET MIDWAY NC	DIST	100.00	13.00	
36	UNA RET SPARTANBURG SC	DIST	100.00	13.00	
37	UNA RET SPARTANBURG SC	DIST	100.00	13.00	
38	UNC-CH DEL 1 CAMERON CHAPEL HILL NC	DIST	100.00	13.00	
39	UNC-CH DEL 1 CAMERON CHAPEL HILL NC	DIST	100.00	13.00	
40	UNC-CH DEL 2 SOUTH CHAPEL HILL NC	DIST	100.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	UNIFI MADISON T&D MADISON NC	DIST	100.00	24.00	
2	UNIFI YADKINVILLE T&D STA 1 YADKINVILLE NC	DIST	100.00	13.00	
3	UNIFI YADKINVILLE T&D STA 1 YADKINVILLE NC	DIST	100.00	13.00	
4	UNIFI YADKINVILLE T&D STA 2 YADKINVILLE NC	DIST	100.00	24.00	
5	UNIFI YADKINVILLE T&D STA 2 YADKINVILLE NC	DIST	100.00	24.00	
6	UNIV OF N C CHARLOTTE STA 2 CHARLOTTE NC	DIST	100.00	44.00	
7	UPWARD RD RET HENDERSONVILLE NC	DIST	100.00	13.00	
8	UPWARD RD RET HENDERSONVILLE NC	DIST	100.00	13.00	
9	URQUHART STEAM STA AUGUSTA GA	TRANS	100.00	13.00	
10	VALDESE RET VALDESE NC	DIST	44.00	2.40	0.60
11	VALDESE RET VALDESE NC	DIST	44.00	2.40	0.60
12	VALDESE RET VALDESE NC	DIST	44.00	2.40	0.60
13	VALDESE RET VALDESE NC	DIST	44.00	13.00	
14	VALDESE RET VALDESE NC	DIST	44.00	13.00	
15	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
16	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
17	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
18	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
19	VALDESE TIE VALDESE NC	TRANS	100.00	44.00	
20	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
21	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
22	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
23	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
24	VALMEAD RET LENOIR NC	DIST	44.00	13.00	
25	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
26	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
27	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
28	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
29	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
30	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
31	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
32	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
33	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	2.40
34	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	2.40
35	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	2.40
36	VAN WYCK TIE VAN WYCK SC	DIST	100.00	44.00	
37	VAN WYCK TIE VAN WYCK SC	DIST	100.00	44.00	
38	VAN WYCK TIE VAN WYCK SC	DIST	24.00	0.20	
39	VANDALIA RET GREENSBORO NC	DIST	100.00	24.00	
40	VANDALIA RET GREENSBORO NC	DIST	100.00	24.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	VANDALIA RET GREENSBORO NC	DIST	100.00	24.00	
2	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
3	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
4	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
5	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
6	VERDAE RET GREENVILLE SC	DIST	100.00	24.00	
7	VERDAE RET GREENVILLE SC	DIST	100.00	13.00	
8	VICTOR HILL SPARTANBURG SC	DIST	100.00	13.00	
9	VICTOR HILL SPARTANBURG SC	DIST	100.00	13.00	
10	VICTOR HILL SPARTANBURG SC	DIST	100.00	24.00	
11	W FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
12	W FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
13	W GASTONIA RET GASTONIA NC	DIST	100.00	13.00	
14	W GASTONIA RET GASTONIA NC	DIST	100.00	13.00	
15	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
16	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
17	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
18	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
19	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
20	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
21	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
22	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
23	W NORWOOD RET NORWOOD NC	DIST	100.00	24.00	
24	W NORWOOD RET NORWOOD NC	DIST	100.00	24.00	
25	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
26	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
27	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
28	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
29	WADDELL RD RET GREENVILLE SC	DIST	100.00	13.00	
30	WADDELL RD RET GREENVILLE SC	DIST	100.00	13.00	
31	WADSWORTH RET SPARTANBURG SC	DIST	100.00	13.00	
32	WADSWORTH RET SPARTANBURG SC	DIST	100.00	13.00	
33	WALDEN RET SPARTANBURG SC	DIST	100.00	24.00	
34	WALHALLA TIE WALHALLA SC	TRANS	100.00	44.00	
35	WALHALLA TIE WALHALLA SC	TRANS	100.00	44.00	
36	WALHALLA TIE WALHALLA SC	TRANS	100.00	44.00	
37	WALHALLA TIE WALHALLA SC	TRANS	44.00	0.20	
38	WALKER TIE HARMONY SC	TRANS	100.00	44.00	
39	WALKER TIE HARMONY SC	TRANS	100.00	44.00	
40	WALKER TIE HARMONY SC	TRANS	24.00	0.20	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	WALKER TIE HARMONY SC	TRANS	24.00	0.20	
2	WALKERTOWN RET WALKERTOWN NC	DIST	100.00	13.00	
3	WALKERTOWN RET WALKERTOWN NC	DIST	100.00	13.00	
4	WALLACE RD RET MIDLAND NC	DIST	100.00	24.00	
5	WALNUT COVE TIE WALNUT COVE NC	TRANS	100.00	44.00	
6	WALNUT COVE TIE WALNUT COVE NC	TRANS	100.00	44.00	
7	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	24.00	13.00
8	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	24.00	7.00
9	WALNUT COVE TIE WALNUT COVE NC	TRANS	24.00	0.20	
10	WARE PLACE RET PELZER SC	DIST	44.00	6.90	
11	WARE PLACE RET PELZER SC	DIST	44.00	6.90	
12	WARE PLACE RET PELZER SC	DIST	44.00	6.90	
13	WARE PLACE RET PELZER SC	DIST	44.00	6.90	2.40
14	WARE PLACE RET PELZER SC	DIST	44.00	6.90	
15	WARE PLACE RET PELZER SC	DIST	44.00	6.90	2.40
16	WARE PLACE RET PELZER SC	DIST	44.00	6.90	2.40
17	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
18	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
19	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
20	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
21	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	
22	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
23	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
24	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
25	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
26	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
27	WATEREE HYDRO LUGOFF SC	TRANS	6.90	0.60	
28	WATEREE HYDRO LUGOFF SC	TRANS	6.90	0.60	
29	WATEREE HYDRO LUGOFF SC	TRANS	6.90	0.60	
30	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	0.60
31	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	0.60
32	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	0.60
33	WATERTOWER RET KANNAPOLIS NC	DIST	44.00	13.00	
34	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	
35	WATERTOWER RET KANNAPOLIS NC	DIST	44.00	13.00	
36	WAYNICK RD RET REIDSVILLE NC	DIST	100.00	13.00	
37	WEAVER RET DURHAM NC	DIST	100.00	24.00	
38	WEBBS CHAPEL RET DENVER NC	DIST	44.00	13.00	
39	WEBBS CHAPEL RET DENVER NC	DIST	44.00	13.00	
40	WEBSTER TIE WEBSTER NC	TRANS	161.00	66.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	WEBSTER TIE WEBSTER NC	TRANS	161.00	66.00	
2	WEBSTER TIE WEBSTER NC	TRANS	66.00	13.00	
3	WEBSTER TIE WEBSTER NC	TRANS	66.00	13.00	
4	WEBSTER TIE WEBSTER NC	TRANS	66.00	13.00	
5	WENTWORTH RET WENTWORTH NC	DIST	100.00	13.00	
6	WENTWORTH RET WENTWORTH NC	DIST	100.00	13.00	
7	WESTMINSTER MN WESTMINSTER SC	DIST	100.00	44.00	
8	WESTMINSTER MN WESTMINSTER SC	DIST	100.00	44.00	
9	WESTMINSTER MN WESTMINSTER SC	DIST	100.00	44.00	
10	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
11	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
12	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
13	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
14	WHITE CROSS RET WHITE CROSS NC	DIST	44.00	13.00	
15	WHITE PLAINS RET MT AIRY NC	DIST	100.00	13.00	
16	WHITEHALL RET ANDERSON SC	DIST	100.00	13.00	
17	WHITEHALL RET ANDERSON SC	DIST	100.00	13.00	
18	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
19	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
20	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
21	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
22	WHITSETT RET BURLINGTON NC	DIST	100.00	24.00	
23	WHITSETT RET BURLINGTON NC	DIST	100.00	24.00	
24	WILDCAT TIE CORNELIUS NC	TRANS	100.00	44.00	
25	WILDCAT TIE CORNELIUS NC	TRANS	100.00	44.00	
26	WILDCAT TIE CORNELIUS NC	TRANS	100.00	44.00	
27	WILGROVE RET CHARLOTTE NC	DIST	100.00	24.00	
28	WILGROVE RET CHARLOTTE NC	DIST	100.00	24.00	
29	WILKES TIE NORTH WILKESBORO NC	TRANS	100.00	44.00	
30	WILKES TIE NORTH WILKESBORO NC	TRANS	100.00	44.00	
31	WILKES TIE NORTH WILKESBORO NC	TRANS	24.00	0.20	
32	WILLARD RD RET WINSTON-SALEM NC	DIST	100.00	24.00	
33	WILLIAMSBURG RET REIDSVILLE NC	DIST	100.00	13.00	
34	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
35	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
36	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
37	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
38	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
39	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
40	WILLIAMSTON RET WILLIAMSTON 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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
2	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
3	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
4	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
5	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
6	WILLOW CREEK RET HIGH POINT NC	DIST	100.00	13.00	
7	WILLOW CREEK RET HIGH POINT NC	DIST	100.00	13.00	
8	WINECOFF RET CONCORD NC	DIST	44.00	13.00	
9	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
10	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
11	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
12	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
13	WINECOFF TIE CONCORD NC	TRANS	44.00	0.40	
14	WINECOFF TIE CONCORD NC	TRANS	44.00		
15	WINECOFF TIE CONCORD NC	TRANS	44.00		
16	WINSTON TIE WINSTON-SALEM NC	TRANS	100.00	13.00	
17	WINTHROP UNIV DEL 3 ROCK HILL SC	DIST	24.00	13.00	
18	WITHERS RET CHARLOTTE NC	DIST	100.00	24.00	
19	WITHERS RET CHARLOTTE NC	DIST	100.00	24.00	
20	WOODLAWN TIE CHARLOTTE NC	TRANS	100.00	13.00	
21	WOODLAWN TIE CHARLOTTE NC	TRANS	100.00	13.00	
22	WOODLAWN TIE CHARLOTTE NC	TRANS	100.00	13.00	
23	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
24	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
25	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
26	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00	0.40	
27	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
28	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
29	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
30	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
31	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
32	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
33	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
34	WOODRUFF TIE WOODRUFF SC	TRANS	24.00	0.20	
35	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
36	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
37	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
38	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
39	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
40	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
2	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
3	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
4	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
5	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
6	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
7	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
8	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
9	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
10	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
11	YORK E C DEL 9 HANCOCK SC	DIST	44.00	13.00	
12	YORK RET YORK SC	DIST	100.00	13.00	
13	YORK RET YORK SC	DIST	100.00	13.00	
14	YORK RET YORK SC	DIST	13.00	2.40	0.60
15	YORK RET YORK SC	DIST	13.00	2.40	0.60
16	YORK RET YORK SC	DIST	13.00	2.40	0.60
17	YORK RET YORK SC	DIST	100.00	24.00	13.00
18	ZF TRANSMISSIONS GVILLE LLC GRAY COURT SC	TRANS	100.00	13.00	
19	ZION CHURCH RD RET HICKORY NC	DIST	100.00	13.00	6.90
20	TOTAL		236099.90	54475.54	8510.90
21					
22	TRANSMISSION -				
23	GEORGIA	TRANS			
24	NORTH CAROLINA	TRANS			
25	SOUTH CAROLINA	TRANS			
26	TOTAL				
27					
28	DISTTRIBUTION				
29	NORTH CAROLINA	DIST			
30	SOUTH CAROLINA	DIST			
31	TOTAL	DIST			
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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
3		1				5
3	1					6
3	1					7
3	1					8
20	1					9
20	1					10
	1		AUX			11
20	1					12
20	1					13
12	1					14
12	1					15
10		1				16
10	1					17
10	1					18
10	1					19
10	1					20
10	1					21
10	1					22
185	1					23
185	1		STU			24
185	1		STU			25
300	1					26
300	1		STU			27
300	1		STU			28
300	1		STU			29
336		1				30
50	1		STU			31
200	1					32
448	1					33
45	1					34
448	1					35
1	1		GND	1	500	36
1	1		GND	1	500	37
1	1		GND	1	500	38
9	1		GND	1	9,156	39
1	1					40

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.
336	1					1
336	1					2
336	1					3
336		1				4
336	1					5
336	1					6
336	1					7
1	1					8
1	1					9
10	1					10
10	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
20	1					22
2	1					23
2	1					24
2	1					25
1	1					26
1	1					27
1	1					28
2		1				29
500		1				30
625			STU			31
625	1		STU			32
625	1		STU			33
10	1		STU			34
20	1					35
20	1					36
2		1				37
2	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
2		1				1
2	1					2
2	1					3
2	1					4
3	1					5
3	1					6
3	1					7
15	2					8
20	1					9
20	1					10
12	1					11
12	1					12
12	1					13
12	1					14
20	1					15
20	1					16
20	1					17
13	1					18
20	1		1			19
13	1		1			20
12	1					21
12	1					22
12	1					23
161	1					24
60		1				25
60	1					26
60	1					27
60	1					28
270	1					29
200	1					30
200	1					31
300	1					32
4		1				33
4	1					34
4	1					35
4	1					36
	1		SS			37
1	1		SS			38
3		1				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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
3	1					1
3	1					2
750	1		STU			3
750	1		STU			4
3	1					5
3	1					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
40	1					15
42	1					16
2	1					17
2	1					18
2	1					19
2	1					20
2	1					21
2		1				22
750	1		STU			23
760	1		STU			24
3	1					25
3	1					26
2	1					27
2	1					28
2	1					29
2	1					30
2	1					31
2	1					32
2	1					33
2	1					34
42	1					35
42	1					36
1	1					37
1	1					38
760		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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	1					1
30	1					2
30	1					3
10	1					4
10	1					5
	1					6
2		1				7
2	1					8
2	1					9
2	1					10
1		1				11
1	1					12
1	1					13
1	1					14
1	1					15
1	1					16
1	1					17
3		1				18
3	1					19
3	1					20
3	1					21
30	1					22
30	1					23
30	1					24
	1		SS			25
12	1					26
12	1					27
10	1					28
10	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
2		1				38
2	1					39
2	1					40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
2	1					1
1	1					2
1	1					3
1	1					4
10	1					5
10	1					6
12	1					7
10	1					8
13	1					9
13	1					10
20	1					11
2		1				12
3	1					13
3	1					14
3	1					15
10	1					16
30	1					17
30	1					18
	1		SS			19
10	1					20
10	1					21
10	1					22
13	1		1			23
12	1					24
3		1				25
3	1					26
3	1					27
3	1					28
3		1				29
3	1					30
3	1					31
3	1					32
2	1					33
2	1					34
2	1					35
5		1				36
12	1					37
12	1					38
10	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
10	1		1			1
2	1					2
2	1					3
2	1					4
3		1				5
10	1					6
8	1					7
2	1					8
2	1					9
2	1					10
12	1					11
12	1					12
30	1					13
30		1				14
30	1					15
20	1					16
20	1					17
20	1					18
20	1					19
22	1					20
20	1					21
1	1					22
1	1					23
1	1					24
1		1				25
2	1					26
2	1					27
2	1					28
2		1				29
2	1					30
2	1					31
2	1					32
20	1					33
20	1					34
10	1					35
10	1					36
15	1		STU			37
15	1		STU			38
12	1					39
	1					40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
	1					1
	1					2
4		1				3
4	1					4
4	1					5
4	1					6
4	1					7
4	1					8
4	1					9
2	1					10
2	1					11
2	1					12
20	1					13
20	1					14
12	1					15
12	1					16
2	1					17
2	1					18
2	1					19
1	1					20
1	1					21
1	1					22
3		1				23
12	1					24
13						25
20	1					26
20	1					27
1	1		AUX			28
1	1		AUX			29
1	1		AUX			30
34			STU			31
1	1					32
30		1	STU			33
30		1	STU			34
10	1					35
1	1					36
4	1					37
1	1					38
10	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
4	1					1
1	1					2
100	1		STU			3
1	1		AUX			4
1	1					5
1	1					6
1	1					7
1	1					8
1	1					9
1	1					10
62	1		GND	1	61,700	11
8	1					12
8	1					13
2	1					14
2	1					15
2	1					16
2	1					17
448	1					18
400	1					19
5	1					20
1	1					21
1	1					22
20	1					23
20	1					24
20	1					25
20	1					26
2		1				27
2	1					28
2	1					29
2	1					30
200	1					31
60	1					32
30	1					33
30	1					34
10	1		GND	1	9,561	35
1	1					36
1	1		AUX			37
1	1		AUX			38
1	1		AUX			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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
20	1					1
30	1					2
20	1					3
20	1					4
20	1					5
20	1					6
20	1					7
20	1					8
1	1					9
1	1					10
1	1					11
1		1				12
200	1		STU			13
140	1		STU			14
12	1					15
12	1					16
20	1					17
20	1					18
17		1				19
17	1		1			20
12	1					21
12	1					22
30	1					23
30	1					24
30	1					25
10	1					26
	1					27
12	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
	1		SS			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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
1	1					1
3	1					2
3	1					3
3	1					4
20	1					5
20	1					6
20	1					7
10	1					8
10	1					9
3		1				10
3	1					11
3	1					12
3	1					13
3	1					14
3	1					15
3	1					16
11	1					17
10	1					18
750	1		STU			19
8	1					20
8	1					21
24	1					22
750	1		STU			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
2	1					32
2	1					33
42	1					34
42	1					35
42	1					36
42	1					37
2	1					38
2	1					39
2	1					40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
2	1					1
2	1					2
2	1					3
2	1					4
2	1					5
2	1					6
3	1					7
3	1					8
3	1					9
2	1					10
2	1					11
8	1					12
2	1					13
2	1					14
1	1					15
1	1					16
2	1					17
3	1					18
750	1		STU			19
2		1				20
2		1				21
8	1					22
8	1					23
24	1					24
750	1		STU			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
2	1					34
2	1					35
42	1					36
42	1					37
42	1					38
42	1					39
2	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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.
2	1					1
2	1					2
2	1					3
2	1					4
2	1					5
2	1					6
2	1					7
3	1					8
3	1					9
3	1					10
2	1					11
2	1					12
8	1					13
10	1					14
10	1					15
10	1					16
10	1					17
13	1					18
15	1		STU			19
15	1		STU			20
15	1		STU			21
	1					22
336	1					23
224	1					24
336	1					25
448	1					26
29	1		GND	1	28,672	27
10	1		GND	1	9,561	28
1	1		SS			29
1	1		SS			30
1	1		SS			31
2	1					32
3		1				33
3	1					34
3	1					35
10	1					36
10	1					37
10	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
10	1					1
30	1					2
30	1					3
30	1					4
	1					5
10	1					6
10	1					7
12	1					8
12	1					9
5		1				10
5	1					11
5	1					12
5	1					13
4		1				14
4	1					15
4	1					16
4	1					17
1		1				18
1	1					19
1	1					20
1	1					21
12	1					22
12	1					23
12	1					24
	1					25
1	1					26
1	1					27
1	1					28
20	1					29
12	1					30
12	1					31
12	1					32
12	1					33
12	1					34
125	1					35
	1		SS			36
10	1					37
12	1					38
12	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
12	1					1
4		1				2
4	1					3
4	1					4
4	1					5
	1					6
	1					7
10	1		AUX			8
2	1		GND	1	1,500	9
	1					10
12	1					11
15	1					12
15	1					13
2	1					14
2	1					15
2	1					16
690	1		STU			17
1	1					18
1	1					19
2	1					20
2	1					21
2	1					22
2	1					23
2	1					24
2	1					25
2	1					26
2	1					27
400	1		AUX			28
300	1					29
10	1					30
11	1					31
15	1					32
15	1					33
4		1				34
4	1					35
4	1					36
4	1					37
	1		SS			38
30	1					39
30	1					40

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.
	1		SS			1
10	1					2
10	1					3
30	1					4
30	1					5
30	1					6
30	1					7
2		1				8
2	1					9
2	1					10
2	1					11
11	1					12
20	1					13
20	1					14
8	1					15
8	1					16
45	1					17
45	1					18
	1					19
5	1					20
20	1					21
30	1					22
30	1					23
20	1					24
20	1					25
11	1					26
3	1					27
3	1					28
3	1					29
5	1					30
5	1					31
20	1					32
20	1					33
30	1					34
	1		AUX			35
13	1					36
20	1		2			37
22	1		2			38
175	1		STU			39
101	1		STU			40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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.
1	1					1
1	1					2
1	1		AUX			3
3		1				4
3	1					5
3	1					6
3	1					7
10	1					8
4		1				9
4	1					10
4	1					11
4	1					12
4	1					13
4	1					14
4	1					15
30	1					16
12	1					17
12	1					18
10	1					19
5	1					20
10	1					21
11	1					22
30	1					23
30	1					24
	1		AUX			25
20	1					26
20	1					27
10	1					28
4	1					29
17	1		AUTO-TRANSFORMER			30
17	1		AUTO-TRANSFORMER			31
17	1		AUTO-TRANSFORMER			32
76	1		AUTO-TRANSFORMER			33
						34
12	1					35
12	1					36
10	1					37
20	1					38
20	1					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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
3	1					1
3	1					2
3	1					3
10	1					4
3	1					5
3	1					6
3	1					7
12	1					8
12	1					9
25	1		STU			10
8	1		STU			11
8	1		STU			12
20	1					13
20	1					14
22	1					15
20	1					16
12	1					17
10	1		GND	1	10,000	18
10	1		GND	1	10,000	19
12	1					20
20	1					21
20	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
20	1					31
20	1					32
	1		SS			33
12	1					34
3	1					35
3	1					36
3		1				37
3	1					38
10	1					39
10	1					40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
15	1					1
34	1					2
34	1					3
34	1					4
	1		SS			5
	1					6
	1					7
	1					8
12	1					9
12	1					10
12	1					11
12	1					12
12	1					13
13	1					14
13	1					15
13	1					16
13	1					17
12	1					18
12	1					19
13	1					20
20	1					21
20	1					22
10	1					23
10	1					24
20	1					25
20	1					26
20	1					27
10	1					28
12	1					29
12	1					30
400	1					31
300	1					32
1	1					33
10	1					34
10	1					35
10	1					36
10	1					37
3		1				38
3	1					39
3	1					40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
3	1					1
10	1					2
12	1					3
12	1					4
12	1					5
3		1				6
3	1					7
3	1					8
3	1					9
	1		SS			10
	1		SS			11
	1		SS			12
10	1					13
10	1					14
20	1					15
20	1					16
10	1					17
10	1					18
12	1					19
12	1					20
12	1					21
12	1					22
20	1					23
20	1					24
12	1					25
12	1					26
20	1					27
20	1					28
20	1					29
20	1					30
20	1					31
12	1					32
20	1					33
20	1					34
10	1					35
10	1					36
8	1					37
8	1					38
11	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
20	1					1
20	1					2
20	1					3
20	1					4
20	1		2			5
8	1					6
8	1					7
12	1					8
12	1					9
1	1					10
1	1					11
1	1					12
1		1				13
2		1				14
2	1					15
2	1					16
2	1					17
12	1					18
12	1					19
13	1		1			20
30	1					21
30	1					22
12	1					23
12	1					24
4		1				25
4	1					26
4	1					27
4	1					28
11	1					29
10	1					30
300	1					31
300	1					32
200	1					33
200	1					34
9	1		GND	1	9,145	35
9	1		GND	1	9,156	36
1	1		SS			37
1	1					38
12	1					39
12	1					40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
15	1					1
15	1					2
12	1					3
30	1					4
30	1					5
30	1					6
20	1					7
20	1					8
12	1					9
12	1					10
30	1					11
30	1					12
30	1					13
12	1					14
12	1					15
2	1					16
2	1					17
2	1					18
3		1				19
1	1					20
1	1					21
1	1					22
10	1					23
8	1					24
8	1					25
12	1					26
12	1					27
12	1					28
10	1					29
10	1					30
2		1				31
2	1					32
2	1					33
2	1					34
20	1					35
20	1					36
	1					37
	1					38
25	1		STU			39
22	1		STU			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
22	1					1
10	1					2
8	1					3
8	1					4
3		1				5
3	1					6
3	1					7
3	1					8
2	1					9
2	1					10
2	1					11
10	1					12
2	1					13
2	1					14
2	1					15
3		1				16
3	1					17
3	1					18
3	1					19
10	1					20
10	1					21
8	1					22
8	1					23
10	1					24
20	1					25
20	1					26
20	1					27
20	1					28
30	1					29
30	1					30
11	1					31
11	1					32
11	1					33
11	1					34
11	1					35
11	1					36
10	1					37
20	1					38
20	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
	1		SS			7
	1					8
30	1					9
30	1					10
12	1					11
12	1					12
	1					13
12	1					14
12	1					15
12	1					16
3	1					17
3		1				18
3	1					19
3	1					20
12	1					21
13	1					22
2	1					23
2	1					24
2	1					25
2		1				26
3	1					27
3	1					28
3	1					29
12	1					30
12	1					31
10		1				32
11	1					33
10	1					34
20	1					35
22	1					36
20	1					37
20	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
5	1					1
2	1					2
2	1					3
2	1					4
20	1					5
20	1					6
20	1					7
12	1					8
12	1					9
12	1					10
12	1					11
12	1					12
13	1					13
22	1					14
20	1					15
30	1					16
30	1					17
30	1					18
1	1					19
1	1					20
1	1					21
2		1				22
10	1					23
10	1					24
11	1					25
8	1		STU			26
8	1		STU			27
8	1		STU			28
8	1		STU			29
20	1					30
20	1					31
14	1					32
14	1					33
12	1					34
12	1					35
37	1					36
37	1					37
37						38
6		1				39
6	1					40

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
20	1					3
20	1					4
20	1					5
20	1					6
20	1					7
20	1					8
20	1					9
4	1					10
4	1					11
4	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
10	1					21
10	1					22
10	1					23
10	1					24
5	1					25
10	1					26
12	1					27
12	1					28
12	1					29
	1		AUX			30
13	1					31
13	1					32
20	1					33
12	1					34
12	1					35
20	1					36
20	1					37
12	1					38
12	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
3		1				1
3	1					2
3	1					3
3	1					4
12	1					5
12	1					6
12	1					7
12	1					8
1		1				9
1	1					10
1	1					11
1	1					12
200	1					13
270	1					14
200	1					15
270	1					16
8	1		GND	1	8,230	17
1	1		GND	1	500	18
1	1		GND	1	500	19
1	1		GND	1	500	20
	1		SS			21
	1		SS			22
	1		SS			23
10	1					24
8	1					25
1		1				26
2	1					27
10	1					28
2	1					29
2	1					30
12	1					31
12	1					32
20	1					33
20	1					34
20	1					35
10	1					36
22	1		2			37
20	1					38
30	1					39
30	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
	1		AUX			1
1		1				2
1	1					3
1	1					4
1	1					5
3	1					6
3	1					7
3	1					8
1		1				9
1	1					10
1	1					11
3	1					12
20	1					13
20	1					14
20	1					15
20	1					16
20	1					17
30	1					18
	1					19
11	1					20
2		1				21
2	1					22
2	1					23
2	1					24
1	1					25
1	1					26
1	1					27
5	1					28
5	1					29
10	1					30
10	1		GND	1	10,000	31
20	1					32
20	1					33
30	1					34
30	1					35
30	1					36
20	1					37
20	1					38
3	1					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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
3	1					1
3	1					2
3	1					3
3	1					4
20	1					5
20	1					6
20	1					7
12	1					8
	1					9
20	1					10
20	1					11
20	1					12
10	1					13
300	1					14
300	1					15
19	1		GND	1	19,120	16
1	1		SS			17
20	1					18
20	1					19
20	1					20
12	1					21
12	1					22
20	1					23
20	1					24
3		1				25
3	1					26
3	1					27
3	1					28
60	1					29
60	1					30
30	1					31
30	1					32
	1		SS			33
	1		SS			34
34						35
	1		SS			36
20	1					37
20	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
20	1					1
20	1					2
10	1					3
10	1					4
12	1					5
12	1					6
12	1					7
20	1					8
12	1					9
3		1				10
3	1					11
3	1					12
3	1					13
1	1					14
1	1					15
1	1					16
30	1					17
30	1					18
30	1					19
12	1					20
20	1					21
12	1					22
12	1					23
12	1					24
12	1					25
12	1					26
12	1					27
10	1					28
10	1					29
30	1					30
30	1					31
34	1					32
192	1		STU			33
96	1		STU			34
192	1		STU			35
192	1		STU			36
1	1					37
	1					38
1		1				39
1	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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.
1	1					1
1	1					2
1	1					3
	1					4
1	1					5
1	1					6
3	1					7
500	1					8
500	1					9
500	1					10
192		1				11
12	1					12
12	1					13
12	1					14
10	1					15
10	1					16
20	1					17
20	1					18
20	1					19
205	1		STU			20
1		1				21
1	1		AUX			22
1	1		AUX			23
1	1		AUX			24
1	1		AUX			25
1	1		AUX			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
2		1				35
2	1					36
2	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
1	1					1
1	1					2
10	1					3
10	1					4
30	1					5
30	1					6
10	1					7
8	1					8
12	1					9
12	1					10
20	1					11
20	1					12
3		1				13
3	1					14
3	1					15
3	1					16
10	1					17
10	1					18
20	1					19
22	1		2			20
		1				21
4	1					22
4	1					23
		1				24
2	1					25
2	1					26
2	1					27
20	1					28
20	1					29
20	1					30
12	1					31
20	1					32
30	1					33
30	1					34
30	1					35
2	1		GND	1	1,500	36
2	1		GND	1	1,500	37
2	1		GND	1	1,500	38
1	1		GND	1	1,000	39
1	1		GND	1	1,000	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
1	1		GND	1	1,000	1
1		1				2
3		1				3
3	1					4
3	1					5
3	1					6
11	1					7
22	1					8
20	1					9
4		1				10
4	1					11
4	1					12
4	1					13
4	1					14
4	1					15
4	1					16
4	1					17
4	1					18
400	1					19
400	1					20
19	1		GND	1	19,121	21
19	1		GND	1	19,121	22
2	1		SS			23
4		1				24
4	1					25
4	1					26
4	1					27
4		1				28
4	1					29
4	1					30
4	1					31
	1		SS			32
1		1				33
1	1					34
1	1					35
1	1					36
12	1					37
12	1					38
3		1				39
3	1					40

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.
3	1					1
3	1					2
10	1					3
10	1					4
10	1					5
10	1					6
3	1					7
3	1					8
3	1					9
12	1					10
12	1					11
13	1		1			12
20	1					13
20	1					14
12	1					15
12	1					16
2	1					17
2	1					18
2	1					19
20	1					20
15	1					21
12	1					22
6		1				23
6	1					24
6	1					25
6	1					26
6	1					27
6	1					28
6	1					29
3		1				30
3	1					31
3	1					32
3	1					33
10	1					34
20	1					35
20	1					36
20	1					37
32	1		STU			38
32	1		STU			39
22	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
20	1					1
2	1					2
2	1					3
2	1					4
3		1				5
10	1					6
20	1					7
20	1					8
30	1					9
30	1					10
	1		SS			11
20	1					12
20	1					13
4		1				14
4	1					15
4	1					16
4	1					17
12	1					18
12	1					19
134	1		STU			20
134	1		STU			21
134	1		STU			22
134	1		STU			23
134	1		STU			24
134	1		STU			25
134	1		STU			26
134	1		STU			27
4		1				28
4	1					29
4	1					30
4	1					31
20	1					32
20	1					33
30	1					34
30	1					35
30	1					36
4		1				37
4	1					38
4	1					39
4	1					40

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
12	1					8
20	1					9
20	1					10
5	1					11
		1	SS			12
20	1					13
20	1					14
22	1		2			15
12	1					16
12	1					17
7	1		GND	1	6,859	18
12	1					19
12	1					20
12	1					21
10	1					22
10	1					23
400	1					24
300	1					25
300	1					26
400	1					27
8	1		GND	1	8,230	28
9	1		GND	1	9,145	29
	1					30
	1					31
	1					32
20	1		STU			33
20	1		STU			34
30	1					35
20	1					36
30	1					37
	1		SS			38
12	1					39
12	1					40

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.
12	1					1
12	1					2
13	1					3
30	1					4
30	1					5
30	1					6
10	1					7
10	1					8
12	1					9
20	1					10
20	1					11
13	1					12
15	1					13
17	1					14
	1					15
	1		GND	1		16
	1		GND	1		17
	1		GND	1		18
20	1					19
12	1					20
34	1					21
20	1					22
	1		SS			23
4		1				24
4	1					25
4	1					26
4	1					27
1		1				28
1	1					29
1	1					30
1	1					31
20	1					32
11	1					33
420	1		STU			34
420	1		STU			35
750	1		STU			36
760	1		STU			37
1	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
	1					1
		1				2
6	1					3
10	1					4
10		1				5
30	1					6
30	1					7
30	1					8
30	1					9
30	1					10
30	1					11
11	1					12
10	1					13
	1					14
20	1					15
20	1					16
20	1					17
150	1					18
30	1					19
1	1		GND	1	500	20
1	1		GND	1	500	21
1	1		GND	1	500	22
	1					23
	1					24
	1					25
750	1		STU			26
60	1					27
60	1					28
6	1					29
6	1					30
24	1					31
750	1		STU			32
2	1					33
2	1					34
2	1					35
2	1					36
2	1					37
2	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
2	1					1
2	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
2	1					11
2	1					12
3		1				13
3	1					14
3	1					15
3	1					16
		1				17
500	1					18
500	1					19
500	1					20
2	1					21
2	1					22
33	1		RAC			23
33	1		RAC			24
33	1		RAC			25
33	1		RAC			26
33	1		RAC			27
33	1		RAC			28
	1					29
	1					30
1	1					31
1	1					32
		1				33
20	1					34
20	1					35
1		1				36
1	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
1	1					1
1	1					2
1	1					3
5	1					4
12	1					5
12	1					6
12	1					7
12	1					8
	1		AUX			9
30	1					10
30	1					11
30	1					12
30	1					13
12	1					14
12	1					15
12	1					16
20	1					17
20	1					18
20	1					19
20	1					20
12	1					21
12	1					22
12	1					23
12	1					24
	1	1				25
5	1	1				26
5	1	1				27
5	1	1				28
12	1					29
30	1					30
30	1					31
20	1					32
269	1					33
200	1					34
300	1					35
9	1		GND	1		36
9	1		GND	1	9,156	37
	1		SS			38
3		1				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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
3	1					1
3	1					2
20	1					3
12	1					4
12	1					5
	1					6
12	1					7
12	1					8
						9
2	1					10
2	1					11
2	1					12
4		1				13
4	1					14
4	1					15
4	1					16
20	1					17
20	1					18
20	1					19
20	1					20
20	1					21
10	1					22
30	1					23
30	1					24
10	1					25
20	1					26
20	1					27
20	1					28
10	1					29
10	1					30
10	1					31
12	1					32
12	1					33
12	1					34
12	1					35
	1					36
10	1					37
10	1					38
10	1					39
10	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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.
10	1					1
10	1					2
20	1					3
20	1					4
12	1					5
	1		STATION SERVICE			6
			STATION SERVICE			7
200	1					8
150	1					9
150	1					10
30	1					11
30	1					12
1	1					13
12	1					14
20	1					15
	1					16
2		1				17
2	1					18
2	1					19
2	1					20
6		1				21
10	1					22
10	1					23
10	1					24
3		1				25
3	1					26
3	1					27
3	1					28
10	1					29
10	1					30
1	1					31
1	1					32
1	1					33
3		1				34
3	1					35
3	1					36
3	1					37
20	1					38
20	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
20	1					1
12	1					2
15	1					3
3		1				4
3	1					5
3	1					6
3	1					7
2		1				8
2	1					9
2	1					10
2	1					11
10	1					12
10	1					13
6	1					14
6	1					15
6	1					16
6		1				17
6	1					18
6	1					19
6	1					20
2		1				21
2	1					22
2	1					23
2	1					24
10	1					25
12	1					26
400	1					27
270	1					28
448	1					29
12	1					30
9	1		GND	1	9,156	31
270						32
2	1		SS			33
200	1					34
200	1					35
200	1					36
200	1					37
19	1		GND	1	19,120	38
19	1		GND	1	19,120	39
	1		SS			40

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.
	1		SS			1
	1		SS			2
8	1					3
8	1					4
22	1					5
20	1					6
12	1					7
12	1					8
20	1					9
20	1					10
20	1					11
27	1					12
27	1					13
15	1					14
	1		SS			15
	1		SS			16
	1					17
11	1					18
10	1					19
10	1					20
10	1					21
12	1					22
12	1					23
12	1					24
13	1		1			25
22	1					26
20	1					27
30	1					28
30	1					29
30	1					30
30	1					31
10	1					32
11	1					33
300	1					34
448	1					35
400	1					36
2	1		AUX			37
333		1				38
333	1					39
333	1					40

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.
373	1					1
19	1		GND	1	19,120	2
33	1		RAC			3
33	1		RAC			4
33	1		RAC			5
6	1					6
6	1					7
6	1					8
6		1				9
6	1					10
6	1					11
6	1					12
6	1					13
6	1					14
6	1					15
	1		AUX			16
3		1				17
3	1		STU			18
3	1		STU			19
3	1		STU			20
3	1		STU			21
3	1		STU			22
3	1		STU			23
3		1				24
3		1				25
3		1				26
	1					27
	1					28
	1					29
20	1					30
5	1					31
5	1					32
12	1					33
12	1					34
10	1					35
10	1					36
1						37
5	1					38
20	1					39
20	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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.
4		1				1
4	1					2
4	1					3
4	1					4
200	1					5
200	1					6
200	1					7
9	1		GND	1	9,156	8
1	1		SS			9
12	1					10
12	1					11
5	1					12
5	1					13
5	1					14
4	1					15
4	1					16
4	1					17
4		1				18
22	1					19
20	1					20
	1		SS			21
22						22
20	1	1				23
12	1					24
12	1					25
	1					26
	1					27
500		1				28
500	1					29
500	1					30
500	1					31
33	1		RAC			32
33	1		RAC			33
33	1		RAC			34
33	1		RAC			35
33	1		RAC			36
33	1		RAC			37
	1		SS			38
	1		SS			39
1000	1		STU			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
45	1					1
2	1					2
	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
	1		AUX			12
30	1					13
52		1				14
2		1				15
2		1				16
1000	1		STU			17
45	1					18
2	1					19
	1					20
1	1					21
2		1				22
2	1					23
2	1					24
2	1					25
2	1					26
1	1					27
1	1					28
45	1					29
373		1				30
373	1		STU			31
373	1		STU			32
373	1		STU			33
45	1					34
2	1					35
	1					36
2	1					37
2	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
2	1					1
1	1					2
1	1					3
45	1					4
12	1					5
15		1				6
12	1					7
22	1					8
22	1					9
5		1				10
5	1					11
5	1					12
5	1					13
2		1				14
2	1					15
2	1					16
2	1					17
11	1					18
20	1					19
2		1				20
2	1					21
2	1					22
2	1					23
1	1					24
1	1					25
1	1					26
10	1					27
15	1		STU			28
15	1					29
12	1					30
12	1					31
20	1					32
20	1					33
3		1				34
3	1					35
3	1					36
3	1					37
200	1					38
200	1					39
200	1		4			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
8						1
4	1					2
10	1					3
20	1	1				4
20	1					5
20	1					6
10	1					7
12	1					8
20	1					9
300	1					10
300	1					11
269						12
250		1				13
250	1					14
250	1					15
250	1					16
280	1					17
280	1					18
280	1					19
2	1		SS			20
1	1					21
20	1					22
20	1					23
20	1					24
20	1					25
200	1					26
200	1					27
400	1					28
29	1		GND	1	28,672	29
29	1		GND	1	28,672	30
1	1		SS			31
400	1					32
400	1					33
12	1					34
19	1					35
1	1					36
19	1					37
12	1					38
12	1					39
20	1					40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	1					1
5	1					2
5	1					3
20	1	1				4
20	1					5
10	1					6
1	1					7
1	1					8
1	1					9
1		1				10
10	1					11
10	1					12
10	1					13
10	1					14
20	1					15
3		1				16
3	1					17
3	1					18
3	1					19
1	1					20
1	1					21
1	1					22
12	1					23
12	1					24
12	1					25
3	1		1			26
3	1		1			27
3	1		1			28
2		1	NULL			29
2	1		1			30
2	1		1			31
2	1		1			32
	1		SS			33
12	1					34
12	1					35
12	1					36
20	1					37
20	1					38
20	1					39
20	1					40

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.
20	1					1
4		1				2
4	1					3
4	1					4
4	1					5
4	1					6
4	1					7
4	1					8
	1					9
22	1		1			10
20	1					11
30	1					12
30	1					13
34	1					14
200	1					15
200	1					16
30	1					17
60	1					18
60	1					19
19	1		GND	1	19,120	20
9	1		GND	1	9,145	21
1	1		SS			22
20	1					23
20	1					24
20	1					25
10	1					26
300	1					27
300	1					28
300	1					29
500		1				30
500	1					31
500	1					32
500	1					33
29	1		GND	1	28,672	34
33		1				35
33	1		RAC			36
33	1		RAC			37
33	1		RAC			38
1	1		SS			39
1	1					40

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
20	1					3
22	1					4
	1					5
1	1					6
4	1					7
1	1					8
1	1					9
8	1					10
10	1					11
10	1					12
8	1					13
10	1					14
34	1					15
30	1	1				16
30	1					17
20	1					18
20	1					19
20	1					20
20	1					21
20	1					22
20	1					23
12	1					24
12	1					25
30	1					26
30	1					27
30	1					28
20	1					29
20	1					30
20	1					31
20	1					32
20	1					33
12	1					34
15	1					35
12	1					36
4	1					37
4	1					38
4	1					39
4	1					40

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
20	1					4
20	1					5
12	1					6
12	1					7
20	1					8
20	1					9
30	1					10
30	1					11
30	1					12
15	1		STU			13
15	1		STU			14
15	1		STU			15
30	1					16
30	1					17
	1					18
13	1					19
12	1					20
4		1				21
4	1					22
4	1					23
4	1					24
20	1					25
20	1					26
12	1					27
12	1					28
269	1					29
269	1					30
13	1					31
13		1				32
13	1					33
13	1					34
13	1					35
10	1		STU			36
	1		GND	1		37
	1		GND	1		38
	1		GND	1		39
2	1		GND	1	1,667	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
10	1					1
10	1					2
34	1					3
12	1					4
12	1					5
10		1				6
6	1					7
6	1					8
6	1					9
12	1					10
12	1					11
20	1					12
20	1					13
8	1		STU			14
8	1		STU			15
8	1		STU			16
8	1		STU			17
1	1					18
1	1					19
20	1					20
20	1					21
4		1				22
4	1					23
4	1					24
4	1					25
2		1				26
3	1					27
3	1					28
3	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
20	1					38
20	1					39
22	1					40

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.
20	1					1
20	1					2
22	1					3
10	1					4
2		1				5
2	1					6
2	1					7
2	1					8
10	1					9
10	1					10
400	1					11
400	1					12
448	1					13
1	1		AUX			14
29	1		GND	1	28,672	15
10	1					16
10	1					17
30	1					18
30	1					19
10	1					20
5	1					21
8	1					22
8	1					23
10	1					24
8	1					25
22	1					26
20	1					27
10	1					28
17	1					29
448	1					30
400	1					31
19	1		GND	1	19,120	32
1	1					33
20	1					34
20	1					35
3	1					36
3	1					37
3	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
4	1					1
4	1					2
4	1					3
4	1					4
4	1					5
3		1				6
3	1					7
3	1					8
3	1					9
	1					10
2	1					11
2	1					12
1	1					13
1	1					14
1	1					15
2		1				16
2	1					17
12	1					18
2		1				19
2	1					20
2	1					21
2	1					22
2	1					23
2	1					24
2	1					25
34	1					26
34	1					27
	1		SS			28
10	1					29
10	1					30
10	1					31
10	1					32
10	1					33
20	1					34
22	1					35
20	1					36
20	1					37
12	1					38
12	1					39
34	1					40

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.
34	1					1
20	1					2
20	1					3
2	1					4
2	1					5
2	1					6
2		1				7
20	1					8
20	1					9
12	1					10
300	1					11
300	1					12
19	1		GND	1	19,120	13
19	1		GND	1	19,120	14
2	1		SS			15
2		1				16
2	1					17
2	1					18
2	1					19
1	1					20
1	1					21
1	1					22
20	1					23
20	1					24
20	1					25
20	1					26
10	1					27
10	1					28
3		1				29
3	1					30
3	1					31
3	1					32
300	1					33
200	1					34
200	1					35
10	1		GND	1	9,561	36
10	1		GND	1	9,561	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
11	1					1
11	1					2
22	1					3
10	1					4
10	1					5
10	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
6		1				15
6	1					16
6	1					17
6	1					18
20	1					19
	1		SS			20
20	1					21
20	1					22
12	1					23
	1		GND	1		24
20	1					25
30	1					26
12	1					27
12	1					28
13	1		1			29
22	1		1			30
270	1					31
400	1					32
400	1					33
1	1					34
1	1					35
3		1				36
3	1					37
3	1					38
3	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
10	1					1
20	1					2
12	1					3
20	1					4
20	1					5
20	1					6
20	1					7
20	1					8
12	1					9
4		1				10
4	1					11
4	1					12
4	1					13
4	1					14
4	1					15
4	1					16
34	1					17
30	1					18
20	1					19
20	1					20
20	1					21
30	1					22
30	1					23
	1					24
20	1		GND	1	20,000	25
22	1					26
12	1					27
12	1					28
12	1					29
22	1					30
20	1					31
37	1					32
20	1					33
20	1					34
20	1					35
20	1					36
25	1		1			37
30	1		1			38
45	1		4			39
5	1		1			40

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.
	1		1			1
12	1					2
12	1					3
20	1					4
20	1					5
10	1					6
11	1					7
	1					8
10	1					9
10	1					10
10	1					11
10	1					12
9	1		GND	1	9,145	13
	1					14
4		1				15
4	1					16
4	1					17
4	1					18
30	1					19
34	1					20
20	1					21
20	1					22
4	1					23
4	1					24
4	1					25
	1					26
4		1				27
22	1					28
22	1					29
12	1					30
12	1					31
10	1		STU			32
20	1					33
20	1					34
4		1				35
4	1					36
4	1					37
4	1					38
3		1				39
3	1					40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
3	1					1
3	1					2
9		1				3
9	1		STU			4
9	1		STU			5
9	1		STU			6
50	1					7
30	1					8
5	1					9
1	1		GND	1	1,000	10
1	1		GND	1	1,000	11
1	1		GND	1	1,000	12
	1		SS			13
20	1					14
20	1					15
336	1					16
200	1					17
448	1					18
9	1		GND	1	9,145	19
8	1		GND	1	8,230	20
1	1					21
1	1					22
2		1				23
2	1					24
2	1					25
2	1					26
3	1					27
3	1					28
3	1					29
12	1					30
12	1					31
12	1					32
38	1					33
38	1					34
12	1					35
20	1					36
20	1					37
1		1				38
1	1					39
1	1					40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
1	1					1
3		1				2
3	1					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
10	1					12
10	1					13
20	1					14
20	1					15
12	1					16
12	1					17
20	1					18
20	1		REG			19
1		1				20
1	1					21
1	1					22
1	1					23
2		1				24
2	1					25
2	1					26
3	1					27
2		1				28
2	1					29
2	1					30
2	1					31
2		1				32
2	1					33
2	1					34
2	1					35
10	1					36
20	1					37
20	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
3	1					1
3	1					2
3	1					3
3		1				4
3	1					5
3	1					6
3	1					7
2		1				8
2	1					9
2	1					10
2	1					11
10	1					12
11	1					13
250	1					14
250	1					15
1	1					16
1	1					17
10	1					18
10	1					19
		1				20
2		1				21
		1				22
2	1					23
2	1		STU			24
2	1		STU			25
2	1		STU			26
10	1		GND	1	9,561	27
	1					28
	1					29
	1					30
3	1					31
3	1					32
3	1					33
3		1				34
12	1					35
20	1					36
20	1					37
34	1					38
34	1					39
30	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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
12	1					2
12	1					3
20	1					4
20	1					5
22	1					6
12	1					7
13	1					8
65	1		STU			9
2	1					10
2	1					11
2	1					12
10	1					13
10	1					14
6		1				15
6	1					16
6	1					17
6	1					18
20	1					19
4		1				20
4	1					21
4	1					22
4	1					23
10	1					24
2		1				25
2	1					26
2	1					27
3	1					28
1		1				29
1	1					30
1	1					31
1	1					32
1	1					33
1	1					34
1	1					35
20	1					36
12	1					37
	1					38
20	1					39
20	1					40

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.
20	1					1
2		1				2
2	1					3
2	1					4
2	1					5
20	1					6
20	1					7
37	1					8
37	1					9
37	1					10
10	1					11
5	1					12
12	1					13
12	1					14
3		1				15
3	1					16
3	1					17
3	1					18
2		1				19
2	1					20
2	1					21
2	1					22
12	1					23
12	1					24
4	1					25
4	1					26
4	1					27
12	1					28
20	1					29
20	1					30
20	1					31
20	1					32
12	1					33
12	1					34
12	1					35
12	1					36
	1		SS			37
20	1					38
20	1					39
	1		SS			40

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.
	1		SS			1
13	1					2
13	1					3
20	1					4
30	1		RAC			5
20	1					6
2	1					7
		1				8
	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
2	1					19
2	1					20
10	1					21
10	1		STU			22
10	1		STU			23
10	1		STU			24
10	1		STU			25
10	1		STU			26
	1					27
	1					28
	1					29
1	1					30
1	1					31
1	1					32
10	1					33
2		1				34
10	1					35
12	1					36
20	1					37
10	1					38
10	1					39
45	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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.
45	1					1
10	1					2
10	1					3
	1					4
13	1					5
12	1					6
12	1					7
12	1					8
12	1					9
		1				10
	1					11
	1					12
	1					13
10	1					14
12	1					15
20	1					16
20	1					17
5		1				18
5	1					19
5	1					20
5	1					21
20	1					22
20	1					23
20	1					24
20	1					25
20	1					26
30	1					27
30	1					28
20	1					29
20	1					30
	1					31
20	1					32
12	1					33
4		1				34
4	1					35
4	1					36
4	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) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
1	1					1
4		1				2
4	1					3
4	1					4
4	1					5
12	1					6
12	1					7
12	1					8
268	1					9
200	1					10
300	1					11
300	1					12
1	1		AUX			13
29	1		GND	1	28,672	14
10	1		GND	1	9,561	15
20	1					16
11	1					17
20	1					18
20	1					19
20	1					20
20	1					21
20	1					22
300	1					23
300	1					24
300	1					25
1	1		AUX			26
29	1		GND	1	28,672	27
29	1		GND	1	28,672	28
8	1					29
8	1					30
12	1					31
30	1					32
30	1					33
	1					34
20	1		1			35
20	1					36
15	1		STU			37
15	1		STU			38
15	1		STU			39
15	1		STU			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	05/29/2019	End of 2018/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.
12	1					1
12	1					2
22	1					3
22	1					4
6		1				5
6	1					6
6	1					7
6	1					8
5	1					9
10	1					10
10	1					11
12	1					12
12	1					13
1	1					14
1	1					15
1	1					16
12	1					17
22	1		1			18
12	1					19
90438	2529	206		71	730,865	20
						21
						22
65	1					23
46350	620	30				24
27492	434	30				25
73907	1055	60				26
						27
						28
12561	1042	96				29
3970	432	50				30
16531	1474	146				31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Services provided by Duke Energy Business Services	Duke Energy Business Services, LLC	Various	1,024,462,669
3				
4	Customer & Market services	Duke Energy Progress, LLC	Various	16,105,686
5	Generation services	Duke Energy Progress, LLC	Various	27,184,363
6	Other goods and services	Duke Energy Progress, LLC	Various	3,991,897
7	Transmission and Distribution services	Duke Energy Progress, LLC	Various	29,411,338
8				
9	Customer & Market services	Duke Energy Florida, LLC	Various	1,684,166
10	Generation services	Duke Energy Florida, LLC	Various	1,464,607
11	Other goods and services	Duke Energy Florida, LLC	Various	344,153
12	Transmission and Distribution services	Duke Energy Florida, LLC	Various	4,126,047
13				
14	Customer & Market services	Duke Energy Indiana, LLC	Various	217,042
15	Generation services	Duke Energy Indiana, LLC	Various	640,461
16	Other goods and services	Duke Energy Indiana, LLC	Various	601,460
17	Transmission and Distribution services	Duke Energy Indiana, LLC	Various	1,906,836
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	24,296,651
22				
23	Customer & Market services	Duke Energy Progress, LLC	Various	45,177,566
24	Generation services	Duke Energy Progress, LLC	Various	485,821,489
25	Other goods and services	Duke Energy Progress, LLC	Various	41,276,539
26	Transmission and Distribution services	Duke Energy Progress, LLC	Various	37,001,908
27				
28	Customer & Market services	Duke Energy Florida, LLC	Various	18,732,349
29	Generation services	Duke Energy Florida, LLC	Various	65,013,993
30	Other goods and services	Duke Energy Florida, LLC	Various	8,650,047
31	Transmission and Distribution services	Duke Energy Florida, LLC	Various	16,876,326
32				
33	Customer & Market services	Duke Energy Indiana, LLC	Various	20,720,683
34	Generation services	Duke Energy Indiana, LLC	Various	3,186,975
35	Other goods and services	Duke Energy Indiana, LLC	Various	3,383,342
36	Transmission and Distribution services	Duke Energy Indiana, LLC	Various	11,515,987
37				
38	Customer & Market services	Duke Energy Kentucky, Inc.	Various	3,472,555
39	Generation services	Duke Energy Kentucky, Inc.	Various	33,991,789
40	Other goods and services	Duke Energy Kentucky, Inc.	Various	864,510
41	Transmission and Distribution services	Duke Energy Kentucky, Inc.	Various	1,923,431
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Customer & Market services	Duke Energy Ohio, Inc.	Various	212,730

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/29/2019	Year/Period of Report End of 2018/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	-902
4	Other goods and services	Duke Energy Ohio, Inc.	Various	394,965
5	Transmission and Distribution services	Duke Energy Ohio, Inc.	Various	1,826,191
6				
7	Customer & Market services	Duke Energy Kentucky, Inc.	Various	35,469
8	Gas Distribution Services	Duke Energy Kentucky, Inc	Various	-2,321
9	Generation services	Duke Energy Kentucky, Inc.	Various	3,462
10	Other goods and services	Duke Energy Kentucky, Inc.	Various	14
11	Transmission and Distribution services	Duke Energy Kentucky, Inc.	Various	545,532
12				
13	Gas Distribution Services	Piedmont Natural Gas Company, Inc.	Various	9,738,562
14				
15	Other goods and services	North/South Insurance Co		71,060,000
16				
17	Other goods and services	Duke Energy Commercial Enterprises	Various	946,153
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Customer & Market services	Duke Energy Ohio, Inc.	Various	20,819,469
22	Generation services	Duke Energy Ohio, Inc.	Various	279,585
23	Other goods and services	Duke Energy Ohio, Inc.	Various	886,814
24	Transmission and Distribution services	Duke Energy Ohio, Inc.	Various	7,578,593
25				
26	Customer & Market services	Piedmont Natural Gas Company, Inc.	Various	4,547,935
27	Generation services	Piedmont Natural Gas Company, Inc.	Various	187,798
28	Other goods and services	Piedmont Natural Gas Company, Inc.	Various	280,872
29	Transmission and Distribution services	Piedmont Natural Gas Company, Inc.	Various	9,115,143
30				
31	Other goods and services	Duke Energy One, Inc.	Various	251,681
32				
33	Other goods and services	Cinergy Solutions	Various	5,744,878
34				
35	Other goods and services	Claiborne Energy Services	Various	
36				
37	Other goods and services	Duke Energy Beckjord LLC	Various	1,043,705
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 2 Column: a

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

- 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

Schedule	Page No.

Schedule	Page No.