THIS FILING IS		
Item 1: [X] 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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Carolinas, LLC	End of 2017/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	02 Year/Period of Report
Duke Energy Carolinas, LLC	End of 2017/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	06 Title of Contact Person
Jennifer Iannotti	Analyst

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*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(704) 382-8029	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018

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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
William E. Currens Jr.		
02 Title		
SVP, Chief Accting Off & Controller	William E. Currens Jr.	04/12/2018

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.

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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.

William E. Currens, Jr.
Senior Vice President, Chief Accounting Officer & 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) [X] No

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 04/12/2018	Year/Period of Report End of 2017/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 2017 Duke Energy Corporation Form 10-K filed with the SEC in February, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
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Schedule Page: 103 Line No.: 2 Column: d

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

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

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

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

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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 H. Anderson	509,850
2	Chief Human Resources Officer		
3			
4	Senior Vice President, Chief Accounting Officer	William E. Currens, Jr.	305,910
5	and Controller		
6			
7	Treasurer and Senior Vice President, Tax	Stephen Gerard De May	372,468
8			
9	Executive Vice President Energy Solutions and	Douglas F. Esamann	585,000
10	President, Midwest and Florida Regions		
11			
12	President, North Carolina	David B. Fountain	379,148
13			
14	President, South Carolina	Kodwo Ghartey-Tagoe	333,176
15			
16	Chief Executive Officer	Lynn J. Good	1,350,000
17			
18	Executive Vice President and	Dhiaa M. Jamil	787,500
19	Chief Operating Officer		
20			
21	Executive Vice President	Julia S. Janson	625,000
22	Chief Legal Officer and Secretary through 04/30/2017;		
23	Executive Vice President, External Affairs,		
24	Chief Legal Officer and Corporate Secretary,		
25	effective 05/01/2017		
26			
27	Executive Vice President, Customer and Delivery	Lloyd M. Yates	686,753
28	Operations and President, Carolinas Region		
29			
30	Executive Vice President and President	Franklin H. Yoho	490,000
31	Natural Gas		
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33	Executive Vice President and Chief Financial Officer	Steven K. Young	693,000
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	
6	Officer	
7		
8	Lloyd M. Yates	550 South Tryon Street, Charlotte, NC 28202
9	Executive Vice President, Customer and Delivery	
10	Operations and President, Carolinas	
11	Region	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	Joint Owner Tariff Volume 4	ER17-2567
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20170515-5188	05/15/2017	ER11-3585	Informational Filing with	Joint OATT Tariff Volume 4
2				2017 Annual Update for the	
3				OATT Formula Transmission	
4				Rate of Duke Energy	
5				Carolinas, LLC	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	c	14
2	117	Statement of Income	c	62,63,64,65,66,67
3	205	Electric Plant in Service	g	46
4	207	Electric Plant in Service	g	58
5	207	Electric Plant in Service	g	58,75
6	219	Accumulated Provision for Depreciation of	b	25,26
7		Electric Utility Plant (Account 108)		
8	219	Accumulated Provision for Depreciation of	c	24,25
9		Electric Utility Plant (Account 108)		
10	227	Materials and Supplies - Transmission	c	8
11	263	Taxes Accrued, Prepaid, and Charged during year	i	5,10,11,17,23,27,28,29,30
12				31,32,33,37,38,39
13	263	Taxes Accrued, Prepaid and Charged during year	i	5
14	275	Accumulated Deferred Income Taxes - Other Property	k	9
15	311	Sales for Resale	k	Subtotal Non-RQ
16	320	Electric Operation and Maintenance Expense	b	5,12,17
17	321	Electric Operation and Maintenance Expense	b	90,91,112
18	321	Electric Operation and Maintenance Expense	b	80
19	323	Electric Operation and Maintenance Expense	b	197,189,191
20	323	Electric Operation and Maintenance Expense	b	185,192,197
21	336	Depreciation and Amortization of Electric Plant	f	1,7,10
22	336	Depreciation and Amortiziation of Electric Plant	f	1,2,3,4,6,10
23	354	Distribution of Salaries and Wages	b	20,24,25
24	275	Accumulated Deferred Income Taxes - Other Property	k	2
25	354	Distribution of Salaries and Wages	b	27
26	355	Distribution of Salaries and Wages	b	65
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None

2. See Notes to Financial Statements, Note 2, "Acquisitions and Dispositions"

3. None

4. In the fourth quarter of 2017 the cost was finalized for the new lease from second quarter 2017 from Piedmont Natural Gas. Payment of $575,256 will be paid by Duke Energy Carolinas, LLC to Piedmont Natural Gas monthly ($6,903,072 annually).

   Acquired amendment to Natural Gas Pipeline and Services Agreement between Piedmont Natural Gas and Duke Energy Carolinas, LLC effective 10/1/2017 thru 9/30/2037 (20 years). Payment of $183,810 annually will by paid by Duke Energy Carolinas, LLC to Piedmont Natural Gas. The lease shares joint ownership with North Carolina Electric Membership Corporation (NCEMC owns 13.33%, Duke Energy Carolinas LLC owns 86.67%). The agreement was authorized by the North Carolinas Utilities Commission on June 29, 2012, and may be amended in Dockets Nos. E-2, Sub 1095, E-7, Sub 1100, and 0-9, Sub 682.

5. None

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

7. None

8. During the third quarter of 2017, Duke Energy Carolinas employees bargained for by IBEW Local 962 and USW Local 7202, and non-represented craft employees were granted a general wage increase that totaled $6,587,025 in annualized costs. This excludes promotions, demotions, job reclassification, etc. and represents the impact of a 3% general wage increase.

   The first quarter compensation cycle had a 3% merit budget and resulted in an annualized impact to the business of $17,393,798 covering 5,770 Duke Energy Carolinas employees.

9. See Notes to Financial Statements, Note 4, "Regulatory Matters" and Note 5, "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 occurred during in 2017.

The changes in officer and directors for Duke Energy Carolinas, LLC. that occurred during the fourth quarter of 2017 are as follows:

Appointments effective 12/01/17

Jack E. Burchfield Jr.	Site Vice President, Oconee
Steven D. Capps	Senior Vice President, Nuclear Corporate
T. Preston Gillespie Jr.	Senior Vice President and Chief Nuclear Officer
Kelvin Henderson	Senior Vice President, Nuclear Operations (NC)
Kim Maza	Vice President, Nuclear Corporate Governance and Oversight
Thomas Daniel Ray	Site Vice President, McGuire

Appointments effective 10/01/17

L. Stanford Sherrill Jr.	Vice President, Workforce Development, Employee and Labor Relations

Resignations effective 12/01/17

Steven D. Capps	Site Vice President, McGuire
T. Preston Gillespie Jr.	Senior Vice President and Nuclear Chief Operating Officer
Kelvin Henderson	Senior Vice President, Nuclear Corporate
John W. Pitesa	Senior Vice President and Chief Nuclear Officer
Thomas Daniel Ray	Site Vice President, Oconee

Resignations effective 10/01/17

L. Stanford Sherrill Jr.	Vice President, Employee Relations and Labor Relations

The changes in officer and directors for Duke Energy Carolinas, LLC. that occurred during the third quarter of 2017 are as follows:

Appointments effective 08/16/17

Joni Y. Davis	Vice President, Marketing and Customer Engagement
Retha Hunsicker	Vice President, Customer Connect Solutions

Appointments effective 08/14/17

Barbara A. Higgins	Senior Vice President and Chief Customer Officer

The changes in officer and directors for Duke Energy Carolinas, LLC. that occurred during the second quarter of 2017 are as follows:

Appointments effective 05/01/17

Donna T. Council	Vice President, Human Resources Business Partners
Julia S. Janson	Executive Vice President, External Affairs, Chief Legal Officer and Secretary
Catherine B. Stancombe	Vice President, Enterprise Operational Excellence
Charles R. Whitlock	Senior Vice President, Strategic Growth Initiatives

Appointments effective 04/01/17

Swati V. Daji	Senior Vice President, Chief Procurement Officer
Eric S. Grant	Vice President, Fuels and Systems Optimization

Resignations effective 05/01/17

Julia S. Janson	Executive Vice President, Chief Legal Officer

	and Secretary
Catherine B. Stancombe	Vice President, Human Resources Business Partners

Resignations effective 04/01/17

Swati V. Daji	Senior Vice President, Fuels and System Optimization

The changes in officer and directors for Duke Energy Carolinas, LLC. that occurred during the first quarter of 2017 are as follows:

Appointments effective 03/20/17

Louis Renjel	Vice President, Federal Government Affairs and Strategic Policy

Appointments effective 03/01/17

Gary J. Hebbeler	Vice President, Gas Operations
Emily G. Henson	Vice President, Distribution Construction and Maintenance - Carolinas West
Rufus Stanley Jackson	Vice President, Distribution Construction and Maintenance - Carolinas East

Appointments effective 02/01/17

Jeffrey A. Corbett	Senior Vice President, Distribution Engineering and Technical Customer Relations
David J. Maxon	Senior Vice President, Distribution Construction and Maintenance
John F. Smith III	Senior Vice President, Distribution Grid Performance and Contractor Operations
Benjamin C. Waldrep	Senior Vice President and Chief Security Officer

Appointments effective 01/01/17

Robert F. Caldwell	Senior Vice President and President, Duke Energy Renewables and Distributed Energy
Joseph W. Donahue	Vice President, Nuclear Engineering
Paul Draovitch	Senior Vice President, Environmental, Health and Safety
Kodwo Ghartey-Tagoe	President, South Carolina

Resignations effective 03/31/17

Robert J. Duncan II	Senior Vice President, Nuclear Operations (NC)

Resignations effective 03/01/17

Robert E. Combs	Vice President, Distribution, Maintenance & Construction - Carolinas West

Resignations effective 02/01/17

Jeffrey A. Corbett	Senior Vice President, Chief Procurement Officer
Terrell N. Garren	Vice President and Chief Security Officer
John F. Smith III	Senior Vice President, Carolinas Distribution Operations
Benjamin C. Waldrep	Vice President, Operational Excellence

Resignations effective 01/01/17

Charles Keith Beam	Vice President, Customer Information Systems - IT
Robert F. Caldwell	President, Duke Energy Renewables and Distributed Energy

	Technology
Paul Draovitch	Senior Vice President, Fossil Hydro Operations
Christopher M. Fallon	Vice President, Nuclear Development
Clark S. Gillespy	President, South Carolina
Ernest J. Kapapoulos Jr.	Vice President, Operations Support
Harry K. Sideris	Senior Vice President, Environmental Health and Safety

14. N/A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	38,269,626,033	36,796,332,162
3	Construction Work in Progress (107)	200-201	2,610,346,436	2,319,769,272
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		40,879,972,469	39,116,101,434
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	15,379,235,049	14,795,088,915
6	Net Utility Plant (Enter Total of line 4 less 5)		25,500,737,420	24,321,012,519
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	315,193,682	336,750,095
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		1	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		1,158,802,565	1,200,997,083
10	Spent Nuclear Fuel (120.4)		652,248,802	556,908,927
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	1,283,591,983	1,191,832,506
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		842,653,067	902,823,599
14	Net Utility Plant (Enter Total of lines 6 and 13)		26,343,390,487	25,223,836,118
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)		118,030,854	120,327,669
19	(Less) Accum. Prov. for Depr. and Amort. (122)		38,522,984	35,814,103
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	13,114,070	11,321,378
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	2,857,728
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		4,114,781,423	3,546,760,318
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)		94,297	9,065,508
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,207,592,030	3,654,518,498
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		15,882,026	13,599,942
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)		356,566,585	402,046,079
41	Other Accounts Receivable (143)		146,007,450	119,749,731
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		9,041,317	9,044,211
43	Notes Receivable from Associated Companies (145)		0	66,344,000
44	Accounts Receivable from Assoc. Companies (146)		110,443,568	180,731,637
45	Fuel Stock (151)	227	229,301,332	290,783,909
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	697,542,126	719,902,512
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	71,125	56,950
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	38,694,923	36,521,765

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	44,420,013	43,768,488
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)		15,298,464	7,933,319
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	4,193
60	Rents Receivable (172)		299,733	201,328
61	Accrued Utility Revenues (173)		300,035,802	279,407,256
62	Miscellaneous Current and Accrued Assets (174)		24,594,139	1,250,000
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)		1,683,416	31,929,553
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		94,297	9,065,508
67	Total Current and Accrued Assets (Lines 34 through 66)		1,972,005,088	2,176,420,943
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		50,054,596	47,848,474
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	2,760,098,689	3,019,657,037
73	Prelim. Survey and Investigation Charges (Electric) (183)		14,113,390	10,920,219
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)		819,880	790,946
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	1,208,726,515	1,120,016,189
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)		63,880,032	70,374,838
82	Accumulated Deferred Income Taxes (190)	234	2,492,302,268	2,720,556,256
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		6,589,995,370	6,990,163,959
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		39,113,995,627	38,045,952,170

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	end of 2017/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	7,643,088,909	7,055,134,480
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	4,810,163	3,017,471
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-7,080,444	-9,497,770
16	Total Proprietary Capital (lines 2 through 15)		11,365,886,081	10,773,721,634
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	9,109,647,708	8,560,231,949
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	698,720,661	786,179,751
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		19,475,590	20,100,965
24	Total Long-Term Debt (lines 18 through 23)		10,088,892,779	9,626,310,735
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		56,762,634	18,357,410
27	Accumulated Provision for Property Insurance (228.1)		99,736,918	93,529,465
28	Accumulated Provision for Injuries and Damages (228.2)		491,016,994	514,617,809
29	Accumulated Provision for Pensions and Benefits (228.3)		89,513,551	95,099,965
30	Accumulated Miscellaneous Operating Provisions (228.4)		5,850,488	1,836,738
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	15,148,777
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		3,931,968	0
34	Asset Retirement Obligations (230)		3,609,220,322	3,895,183,039
35	Total Other Noncurrent Liabilities (lines 26 through 34)		4,356,032,875	4,633,773,203
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		817,851,599	808,309,971
39	Notes Payable to Associated Companies (233)		103,631,000	0
40	Accounts Payable to Associated Companies (234)		228,208,749	267,507,984
41	Customer Deposits (235)		120,757,841	132,008,331
42	Taxes Accrued (236)	262-263	238,979,854	140,059,519
43	Interest Accrued (237)		132,853,878	125,036,866
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	end of 2017/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		10,981,269	10,177,067
48	Miscellaneous Current and Accrued Liabilities (242)		297,226,618	297,314,360
49	Obligations Under Capital Leases-Current (243)		4,089,199	3,189,742
50	Derivative Instrument Liabilities (244)		24,594,139	15,148,777
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	15,148,777
52	Derivative Instrument Liabilities - Hedges (245)		8,707,368	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		3,931,968	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,983,949,546	1,783,603,840
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		500,000	325,000
57	Accumulated Deferred Investment Tax Credits (255)	266-267	232,388,410	202,585,650
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	609,161,169	570,166,666
60	Other Regulatory Liabilities (254)	278	4,571,153,903	1,189,911,046
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)		4,129,591,930	6,452,625,233
64	Accum. Deferred Income Taxes-Other (283)		1,776,438,934	2,812,929,163
65	Total Deferred Credits (lines 56 through 64)		11,319,234,346	11,228,542,758
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		39,113,995,627	38,045,952,170

Schedule Page: 112 Line No.: 34 Column: d

Amount relects the reclassification of the Current portion of ARO liabilities from Account 242 to Account 230 in order to be consistent with the current year presentation.

Schedule Page: 112 Line No.: 48 Column: d

Amount relects the reclassification of the Current portion of ARO liabilities from Account 242 to Account 230 in order to be consistent with the current year presentation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	7,315,231,033	7,332,914,693		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,115,529,868	3,149,546,154		
5	Maintenance Expenses (402)	320-323	627,274,061	674,939,732		
6	Depreciation Expense (403)	336-337	984,369,327	951,571,661		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	52,750,296	45,761,394		
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)		115,028,712	135,873,300		
13	(Less) Regulatory Credits (407.4)		18,197,499	21,202,738		
14	Taxes Other Than Income Taxes (408.1)	262-263	277,321,324	272,463,846		
15	Income Taxes - Federal (409.1)	262-263	212,429,582	122,520,135		
16	- Other (409.1)	262-263	19,575,054	22,693,718		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,418,857,415	1,414,173,472		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,031,927,861	933,438,808		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,298,340	-5,263,008		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)			121,415		
22	(Less) Gains from Disposition of Allowances (411.8)		-219,459	-425,341		
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)		5,767,931,398	5,830,185,614		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,547,299,635	1,502,729,079		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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		
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)	Line No.
						1
7,315,231,033	7,332,914,693					2
						3
3,115,529,868	3,149,546,154					4
627,274,061	674,939,732					5
984,369,327	951,571,661					6
						7
52,750,296	45,761,394					8
						9
						10
						11
115,028,712	135,873,300					12
18,197,499	21,202,738					13
277,321,324	272,463,846					14
212,429,582	122,520,135					15
19,575,054	22,693,718					16
1,418,857,415	1,414,173,472					17
1,031,927,861	933,438,808					18
-5,298,340	-5,263,008					19
						20
	121,415					21
-219,459	-425,341					22
						23
						24
5,767,931,398	5,830,185,614					25
1,547,299,635	1,502,729,079					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)		1,547,299,635	1,502,729,079		
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)		25,596			
33	Revenues From Nonutility Operations (417)		21,881,794	16,229,228		
34	(Less) Expenses of Nonutility Operations (417.1)		19,495,926	10,847,382		
35	Nonoperating Rental Income (418)		-2,964,090	-1,968,489		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,792,692	288,147		
37	Interest and Dividend Income (419)		1,550,841	3,961,105		
38	Allowance for Other Funds Used During Construction (419.1)		105,820,147	101,909,393		
39	Miscellaneous Nonoperating Income (421)		29,319,670	56,692,854		
40	Gain on Disposition of Property (421.1)		947,292	287,219		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		138,826,824	166,552,075		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		228,606	5,032,503		
44	Miscellaneous Amortization (425)		9,979	9,979		
45	Donations (426.1)		4,083,062	62,553,334		
46	Life Insurance (426.2)					
47	Penalties (426.3)		3,870,703	-46,334		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		3,470,140	3,662,833		
49	Other Deductions (426.5)		10,139,650	3,414,039		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		21,802,140	74,626,354		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	3,590,612	3,247,700		
53	Income Taxes-Federal (409.2)	262-263	7,925,742	16,877,171		
54	Income Taxes-Other (409.2)	262-263	929,426	2,102,950		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	32,806,720	19,821,736		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	5,431,647	25,416,824		
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)		39,820,853	16,632,733		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		77,203,831	75,292,988		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		437,490,775	419,512,738		
63	Amort. of Debt Disc. and Expense (428)		5,981,227	6,189,395		
64	Amortization of Loss on Reaquired Debt (428.1)		6,494,805	7,468,644		
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)		6,738,727	2,645,919		
68	Other Interest Expense (431)		-2,023,488	14,693,132		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		44,925,700	38,333,449		
70	Net Interest Charges (Total of lines 62 thru 69)		409,756,346	412,176,379		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,214,747,120	1,165,845,688		
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)		1,214,747,120	1,165,845,688		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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		6,952,264,769	7,800,079,212
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)		1,212,954,428	1,165,557,541
17	Appropriations of Retained Earnings (Acct. 436)			
18			-12,366,386	(13,371,984)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-12,366,386	(13,371,984)
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		-625,000,000	(2,000,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-625,000,000	(2,000,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		7,527,852,811	6,952,264,769
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)		115,236,098	102,869,711
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		115,236,098	102,869,711
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		7,643,088,909	7,055,134,480
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		3,017,471	2,729,324
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,792,692	288,147
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		4,810,163	3,017,471

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	1,214,747,120	1,165,845,688
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	984,369,327	951,571,661
5	Amortization of primarily nuclear fuel	453,332,170	467,770,718
6	Net (Increase) Decrease in MTM and Hedging Transactions	9,816,809	4,628,223
7	Contributions to Qualified Pensions	-8,851	-43,138,852
8	Deferred Income Taxes (Net)	414,304,627	475,139,576
9	Investment Tax Credit Adjustment (Net)	-5,298,340	-5,263,008
10	Net (Increase) Decrease in Receivables	80,260,298	24,991,301
11	Net (Increase) Decrease in Inventory	78,698,190	215,758,508
12	Net (Increase) Decrease in Allowances Inventory	-2,173,158	-5,352,670
13	Net Increase (Decrease) in Payables and Accrued Expenses	76,155,006	108,512,572
14	Net (Increase) Decrease in Other Regulatory Assets	-86,321,652	-104,287,323
15	Net Increase (Decrease) in Other Regulatory Liabilities	-155,643,415	74,485,163
16	(Less) Allowance for Other Funds Used During Construction	105,820,147	101,909,393
17	(Less) Undistributed Earnings from Subsidiary Companies	1,792,692	288,147
18	Impairment Charges		788,146
19	Payments for asset retirement obligations	-270,723,877	-286,906,011
20	Accrued Pension and other post-retirement benefit costs	-3,794,179	4,086,696
21	Other (provide details in footnote):	-59,241,756	8,734,127
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	2,620,865,480	2,955,166,975
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-2,342,415,996	-2,072,359,737
27	Gross Additions to Nuclear Fuel	-287,648,029	-246,962,893
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-105,820,147	-101,909,393
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-2,524,243,878	-2,217,413,237
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	96,866,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-2,124,155,924	-2,832,059,904
45	Proceeds from Sales of Investment Securities (a)	2,127,855,924	2,832,059,904

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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			
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):	-94,539,947	-65,034,048
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-2,548,739,825	-2,185,581,285
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	574,197,000	1,596,588,000
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):	-6,683,973	-9,889,156
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	567,513,027	1,586,698,844
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-115,987,598	-355,841,492
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Net Increase (Decrease) in Intercompany Notes	103,631,000	
78	Net Decrease in Short-Term Debt (c)		
79	Distributions to Parent	-625,000,000	-2,000,000,000
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)	-69,843,571	-769,142,648
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	2,282,084	443,042
87			
88	Cash and Cash Equivalents at Beginning of Period	13,899,942	13,456,900
89			
90	Cash and Cash Equivalents at End of period	16,182,026	13,899,942

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

Claims and expenses related to injuries and damages	(38,710,715)
Debt return on Coal Ash Compliance Costs	(19,519,238)
Charitable contributions related to Piedmont merger commitments	(11,900,000)
Miscellaneous prepaid expenses	(7,365,145)
Cost of removal on final retired plants	(7,320,815)
Insurance proceeds for asbestosis claims	17,251,637
Net retiree medical reimbursements	7,286,959
Other	1,035,561
Total	(59,241,756)

Schedule Page: 120 Line No.: 53 Column: b

Cost of removal of utility plant, net of salvage value	(94,539,947)

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

Issuance Costs	(5,231,834)
Unamortized debt expense associated with master credit facilities	(1,452,139)
Total	(6,683,973)

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

Accrued capital expenditures	315,412,383
Supplemental disclosures:	
Cash paid for interest, net of amount capitalized	397,859,835
Cash paid for income taxes, net	193,018,492

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

Cash and working funds (131 & 135)	13,899,942
Special deposits (132 - 134)	0
Temporary cash investments	0
Total	13,899,942

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

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

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.

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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 Statndards Update (ASU) No. 2017-17 January 1, 2018, GAAP requires that the service cost related to pensions and 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, cost 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. 2017-17. This change is not expected to have a material impact on the financial statements.

The Combined Notes To Consolidated Financial Statements below are as published in the fourth quarter ended December 31, 2017 Form 10-K/A (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 22, 2018. 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, 2017 up to February 22, 2018, the date that Duke Energy Carolinas' U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 12, 2018.

On March 2, 2018, Duke Energy Corporation and Duke Energy Carolinas, LLC (DEC) issued an 8-K stating that the Public Staff - North Carolina Utilities Commission and DEC reached a partial settlement resolving certain issues in the rate case filed on August 25, 2017. This partial settlement will be subject to the review and approval of the North Carolinas Utilities Commission (NCUC). On March 1, 2018, DEC also filed supplemental comments with the NCUC in the Federal Tax Act Proceeding that propose how DEC could implement the impacts of the Federal Tax Cut and Jobs Act of 2017. Hearings related to DEC's rate case have concluded and a decision from the NCUC is expected by mid-2018. Duke Energy Carolinas cannot predict the outcome of this matter.

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**
Duke Energy Corporation	•	•	•	•	•	•	•	•	•	•	•	•		•	•	•	•	•	•	•	•	•	•	•	•
Duke Energy Carolinas, LLC	•		•	•	•	•		•	•	•	•		•	•	•	•	•		•	•	•	•	•	•	•
Progress Energy, Inc.	•		•	•	•	•	•		•	•	•		•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Progress, LLC	•		•	•	•	•			•	•	•		•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Florida, LLC	•		•	•	•	•			•	•	•		•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Ohio, Inc.	•	•	•	•	•	•		•	•	•	•		•	•		•	•		•	•	•	•	•	•	•
Duke Energy Indiana, LLC	•		•	•	•	•		•	•	•	•		•	•	•	•	•		•	•	•	•	•	•	•
Piedmont Natural Gas Company, Inc.	•	•	•	•	•	•			•	•	•	•	•	•	•	•	•		•	•	•	•	•	•	•

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 Corporation (collectively with its subsidiaries, Duke Energy) is an energy company headquartered in Charlotte, North Carolina, subject to regulation by the Federal Energy Regulatory Commission (FERC). Duke Energy operates in the United States (U.S.) primarily through its direct and indirect subsidiaries. Certain Duke Energy subsidiaries are also subsidiary registrants, including Duke Energy Carolinas, LLC (Duke Energy Carolinas); Progress Energy, Inc. (Progress Energy); Duke Energy Progress, LLC (Duke Energy Progress); Duke Energy Florida, LLC (Duke Energy Florida); Duke Energy Ohio, Inc. (Duke Energy Ohio); Duke Energy Indiana, LLC (Duke Energy Indiana) and Piedmont Natural Gas Company, Inc. (Piedmont). When discussing Duke Energy’s consolidated financial information, it necessarily includes the results of its seven separate subsidiary registrants (collectively referred to as the 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) as of December 31, 2016, 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 National Methanol Company (NMC), was completed through two transactions including a sale of assets in Brazil to China Three Gorges (Luxembourg) Energy S.à.r.l. (CTG) and a sale of Duke Energy's remaining Latin American assets in Peru, Chile, Ecuador, Guatemala, El Salvador and Argentina to ISQ Enerlam Aggregator, L.P. and Enerlam (UK) Holding Ltd. (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 where the respective Duke Energy Registrants have control. These Consolidated Financial Statements also reflect the Duke Energy Registrants’ proportionate share of certain jointly owned generation and transmission facilities. 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 North Carolina Utilities Commission (NCUC), Public Service Commission of South Carolina (PSCSC), U.S. Nuclear Regulatory Commission (NRC) and FERC.

Progress Energy is a public utility holding company headquartered in Raleigh, North Carolina, subject to regulation by FERC. Progress Energy conducts operations through its wholly owned subsidiaries, Duke Energy Progress and Duke Energy Florida.

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 Florida Public Service Commission (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, Inc. (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 Public Utilities Commission of Ohio (PUCO), Kentucky Public Service Commission (KPSC) and FERC. On April 2, 2015, Duke Energy completed the sale of its nonregulated Midwest generation business, which sold power into wholesale energy markets, to a subsidiary of Dynegy Inc. (Dynegy). For further information about the sale of the Midwest Generation business, refer to Note 2. Substantially all of Duke Energy Ohio's operations that remain after the sale qualify for regulatory accounting.

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 Indiana Utility Regulatory Commission (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, Tennessee Public Utility Commission (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, 2017, or 2016.

		December 31,	
(in millions)	**Location**	**2017**	**2016**
Duke Energy			
Accrued compensation	Current Liabilities	**$ 757**	$ 765
Duke Energy Carolinas			
Accrued compensation	Current Liabilities	**$ 252**	$ 248
Customer deposits	Current Liabilities	**121**	155
Progress Energy			
Income taxes receivable	Current Assets	**$ 278**	$ 19
Customer deposits	Current Liabilities	**338**	363
Duke Energy Progress			
Customer deposits	Current Liabilities	**$ 129**	$ 141
Accrued compensation	Current Liabilities	**132**	135
Duke Energy Florida			
Customer deposits	Current Liabilities	**$ 208**	$ 222
Duke Energy Ohio			
Income taxes receivable	Current Assets	**$ 36**	$ 16
Customer deposits	Current Liabilities	**46**	62
Duke Energy Indiana			
Customer deposits	Current Liabilities	**$ 45**	$ 44
Piedmont			
Income taxes receivable	Current Assets	**$ 43**	$ 9

Discontinued Operations

The results of operations of the International Disposal Group as well as Duke Energy Ohio's nonregulated Midwest Generation business and Duke Energy Retail Sales, LLC (collectively, Midwest Generation 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 year ended December 31, 2017, the Loss From Discontinued Operations, net of tax on Duke Energy's Consolidated Statement of Operations is entirely attributable to controlling interest. The following table presents Net Income Attributable to Duke Energy Corporation for continuing operations and discontinued operations for the years ended December 31, 2016, and 2015.

	Year ended December 31,	
(in millions)	**2016**	**2015**
Income from Continuing Operations	$ 2,578	$ 2,654
Income from Continuing Operations Attributable to Noncontrolling Interests	7	9
Income from Continuing Operations Attributable to Duke Energy Corporation	$ 2,571	$ 2,645
(Loss) Income From Discontinued Operations, net of tax	$ (408)	$ 177
Income from Discontinued Operations Attributable to Noncontrolling Interests, net of tax	11	6
(Loss) Income From Discontinued Operations Attributable to Duke Energy Corporation, net of tax	$ (419)	$ 171
Net Income	$ 2,170	$ 2,831
Net Income Attributable to Noncontrolling Interests	18	15
Net Income Attributable to Duke Energy Corporation	$ 2,152	$ 2,816

Significant Accounting Policies

Use of Estimates

In preparing financial statements that conform to generally accepted accounting principles (GAAP) in the U.S., 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. 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 for a disallowance of costs for regulated plants under construction, recently completed or abandoned is based on discounted cash flows.

Regulated Fuel and Purchased Gas Adjustment Clauses

The Duke Energy Registrants utilize cost-tracking mechanisms, commonly referred to as fuel adjustment clauses or purchased gas adjustment clauses (PGA). 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 and Cash Equivalents

All highly liquid investments with maturities of three months or less at the date of acquisition are considered cash equivalents.

Restricted Cash

The Duke Energy Registrants have restricted cash related primarily to collateral assets, escrow deposits and variable interest entities (VIEs). Restricted cash balances are reflected in Other within Current Assets and in Other within Other Noncurrent Assets on the Consolidated Balance Sheets. At December 31, 2017, and 2016, Duke Energy had restricted cash totaling $147 million and $137 million, respectively.

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, 2017, and 2016. The components of inventory are presented in the tables below.

	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**

	December 31, 2016							
(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	$ 2,374	$ 767	$ 1,167	$ 813	$ 354	$ 84	$ 312	$ 1
Coal	774	251	314	148	166	19	190	—
Natural gas, oil and other	374	37	236	115	121	34	2	65
Total inventory	$ 3,522	$ 1,055	$ 1,717	$ 1,076	$ 641	$ 137	$ 504	$ 66

Investments in Debt and Equity Securities

The Duke Energy Registrants classify investments into two categories – trading and available-for-sale. Both categories are recorded at fair value on the Consolidated Balance Sheets. Realized and unrealized gains and losses on trading securities are included in earnings. For certain investments of regulated operations, such as substantially all of the Nuclear Decommissioning Trust Funds (NDTF), realized and unrealized gains and losses (including any other-than-temporary impairments (OTTIs)) on available-for-sale securities are recorded as a regulatory asset or liability. Otherwise, unrealized gains and losses are included in Accumulated Other Comprehensive Income (AOCI), unless other-than-temporarily impaired. OTTIs for equity securities and 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

Effective with Piedmont's change in fiscal year end to December 31, as discussed above, Piedmont changed the date of its annual impairment testing of goodwill from October 31 to August 31 to align with the other Duke Energy Registrants.

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 an operating 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.

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 sulfur dioxide (SO_2) and nitrogen oxide (NO_X). Allowances are issued by the U.S. Environmental Protection Agency (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.

Renewable energy certificates 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.

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 (AFUDC) 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,		
	2017	**2016**	**2015**
Duke Energy	**2.8%**	2.8%	2.9%
Duke Energy Carolinas	**2.8%**	2.8%	2.8%
Progress Energy	**2.6%**	2.7%	2.6%
Duke Energy Progress	**2.6%**	2.6%	2.6%
Duke Energy Florida	**2.8%**	2.8%	2.7%
Duke Energy Ohio	**2.8%**	2.6%	2.7%
Duke Energy Indiana	**3.0%**	3.1%	3.0%
Piedmont(a)	**2.3%**		

(a) Piedmont's weighted average depreciation rate was 2.4 percent, 2.4 percent, and 2.5 percent for the annualized two months ended December 31, 2016 and for the years ended October 31, 2016 and 2015, respectively.

In general, when the Duke Energy Registrants retire regulated property, plant and equipment, the original cost plus the cost of retirement, less salvage value, 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 further information.

Nuclear Fuel

Nuclear fuel is classified as Property, Plant and Equipment on the Consolidated Balance Sheets, except for Duke Energy Florida. Nuclear fuel amounts at Duke Energy Florida were reclassified to Regulatory assets pursuant to the Revised and Restated Stipulation and Settlement Agreement approved in November 2013 among Duke Energy Florida, the Florida Office of Public Counsel (Florida OPC) and other customer advocates (the 2013 Settlement).

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 effective tax rate (ETR) when capitalized and increases the ETR when depreciated or amortized. See Note 22 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

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 recoverable.

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 Nuclear Plant (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 U.S. Department of Energy (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 and Unbilled Revenue

Revenues on sales of electricity and natural gas are recognized when service is provided or the product is delivered. 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)	**2017**	**2016**
Duke Energy	**$ 944**	$ 831
Duke Energy Carolinas	**342**	313
Progress Energy	**228**	161
Duke Energy Progress	**143**	102
Duke Energy Florida	**85**	59
Duke Energy Ohio	**4**	2
Duke Energy Indiana	**21**	32
Piedmont	**86**	77

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, Cinergy Receivables Company LLC (CRC) and account for the transfers of receivables as sales. Accordingly, the receivables sold are not reflected on the Consolidated Balance Sheets of Duke Energy Ohio and Duke Energy Indiana. See Note 17 for further information. These receivables for unbilled revenues are shown in the table below.

	December 31,	
(in millions)	**2017**	**2016**
Duke Energy Ohio	**$ 104**	$ 97
Duke Energy Indiana	**132**	123

Allowance for Doubtful Accounts

Allowances for doubtful accounts are presented in the following table.

	December 31,		
(in millions)	**2017**	**2016**	**2015**
Allowance for Doubtful Accounts			
Duke Energy	**$ 14**	$ 14	$ 12
Duke Energy Carolinas	**2**	2	3
Progress Energy	**4**	6	6
Duke Energy Progress	**1**	4	4
Duke Energy Florida	**3**	2	2
Duke Energy Ohio	**3**	2	2
Duke Energy Indiana	**2**	1	1
Piedmont[a]	**2**	3	
Allowance for Doubtful Accounts – VIEs			
Duke Energy	**$ 54**	$ 54	$ 53
Duke Energy Carolinas	**7**	7	7
Progress Energy	**7**	7	8
Duke Energy Progress	**5**	5	5
Duke Energy Florida	**2**	2	3

(a) Piedmont's allowance for doubtful accounts was $2 million as of October 31, 2016, and 2015.

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 normal purchase/normal sale (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 incurred but not yet reported (IBNR), as well as estimated provisions for known claims. IBNR reserve estimates are primarily based upon historical loss experience, industry data and other actuarial assumptions. Reserve estimates are adjusted in future periods as actual losses differ from experience.

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

Unamortized Debt Premium, Discount and Expense

Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the term of the debt issue. The gain or loss on extinguishment associated with refinancing higher-cost debt obligations in the regulated operations is amortized. 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 21 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. From time to time, Duke Energy 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 19 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 Duke Energy Board of Directors (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 20 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. Investment tax credits (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. Other impacts of the Tax Act have been recorded on a provisional basis, see Note 22, “Income Taxes,” for additional information. 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 22 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)	**2017**	**2016**	**2015**
Duke Energy	**$ 376**	$ 362	$ 396
Duke Energy Carolinas	**36**	31	31
Progress Energy	**220**	213	229
Duke Energy Progress	**19**	18	16
Duke Energy Florida	**201**	195	213
Duke Energy Ohio	**98**	100	102
Duke Energy Indiana	**20**	17	34
Piedmont[(a)]	**2**		

(a) Piedmont's excise taxes were immaterial for the two months ended December 31, 2016, and $2 million for the years ended October 31, 2016, and 2015.

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, 2017, and 2016, 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 2017 and 2016 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 2017.

Stock-Based Compensation and Income Taxes. In first quarter 2017, Duke Energy adopted Financial Accounting Standards Board (FASB) guidance, which revised the accounting for stock-based compensation and the associated income taxes. The adopted guidance changed certain aspects of accounting for stock-based payment awards to employees including the accounting for income taxes and classification on the Consolidated Statements of Cash Flows. The primary impact to Duke Energy as a result of implementing this guidance was a cumulative-effect adjustment to retained earnings for tax benefits not previously recognized and additional income tax expense for the 12 months ended December 31, 2017. See the Duke Energy Consolidated Statements of Changes in Equity for further information.

Goodwill Impairment. In January 2017, the FASB issued revised guidance for the subsequent measurement of goodwill. Under the guidance, a company will recognize an impairment to goodwill for the amount by which a reporting unit's carrying value exceeds the reporting unit's fair value, not to exceed the amount of goodwill allocated to that reporting unit. Duke Energy early adopted this guidance for the 2017 annual goodwill impairment test.

The following new accounting standards have been issued, but have not yet been adopted by the Duke Energy Registrants, as of December 31, 2017.

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 to which the entity expects to be entitled in exchange for those goods or services. The amendments in this update also require 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.

Duke Energy has identified material revenue streams, which served as the basis for accounting analysis and documentation of the impact of this guidance on revenue recognition. The accounting analysis included reviewing representative contracts and tariffs for each material revenue stream. Most of Duke Energy's revenue will be in scope of the new guidance. The majority of our sales, including energy provided to residential customers, are from tariff offerings that provide natural gas or electricity without a defined contractual term ("at-will"). For such arrangements, revenue from contracts with customers will be equivalent to the electricity or natural gas supplied and billed in that period (including estimated billings). As such, there will not be a significant shift in the timing or pattern of revenue recognition for such sales.

Also included in the accounting analysis was the evaluation of certain long-term revenue streams including electric wholesale contracts and renewables power purchase agreements (PPAs). For such arrangements, Duke Energy does not expect material changes to the pattern of revenue recognition on the registrants. In addition, Duke Energy has monitored the activities of the power and utilities industry revenue recognition task force including draft accounting positions released in October 2017 and the impact, if any, on Duke Energy's specific contracts and conclusions. Potential revisions to processes, policies and controls, primarily related to evaluating supplemental disclosures required as a result of adopting this guidance, will be evaluated and implemented as necessary. Some revenue arrangements, such as alternative revenue programs and certain PPAs accounted for as leases, are excluded from the scope of the new revenue recognition guidance and, therefore, will be accounted for and evaluated for separate presentation and disclosure under other relevant accounting guidance.

Duke Energy intends to use the modified retrospective method of adoption effective January 1, 2018. Under the modified retrospective method of adoption, prior year reported results are not restated and a cumulative-effect adjustment, if applicable, is recorded to retained earnings at January 1, 2018, as if the standard had always been in effect. In addition, disclosures, if applicable, include a comparison to what would have been reported for 2018 under the previous revenue recognition rules to assist financial statement users in understanding how revenue recognition has changed as a result of this standard and to facilitate comparability with prior year reported results, which are not restated under the modified retrospective approach as described above. Duke Energy will utilize certain practical expedients including applying this guidance to open contracts at the date of adoption and recognizing revenues for certain contracts under the invoice practical expedient, which allows revenue recognition to be consistent with invoiced amounts (including estimated billings) provided certain criteria are met, including consideration of whether the invoiced amounts reasonably represent the value provided to customers. While the adoption of this guidance is not expected to have a material impact on either the timing or amount of revenues recognized in Duke Energy's financial statements, Duke Energy anticipates additional disclosures around the nature, amount, timing and uncertainty of our revenues and cash flows arising from contracts with customers. Duke Energy continues to evaluate what information will be most useful for users of the financial statements, including information already provided in disclosures outside of the financial statement footnotes. These additional disclosures are expected to include the disaggregation of revenues by customer class.

Financial Instruments Classification and Measurement. In January 2016, the FASB issued revised accounting guidance for the classification and measurement of financial instruments. Changes in the fair value of all equity securities will be required to be recorded in net income. Current GAAP allows some changes in fair value for available-for-sale equity securities to be recorded in AOCI. Additional disclosures will be required to present separately the financial assets and financial liabilities by measurement category and form of financial asset. 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.

For Duke Energy, the revised accounting guidance is effective for interim and annual periods beginning January 1, 2018, by recording a cumulative effect adjustment to retained earnings as of January 1, 2018. This guidance is expected to have 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' available-for-sale equity securities are deferred as regulatory assets or liabilities pursuant to accounting guidance for regulated operations.

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 is applied using a modified retrospective approach. Upon adoption, Duke Energy expects to elect the practical expedients, which would require no reassessment of whether existing contracts are or contain leases as well as no reassessment of lease classification for existing leases. Additionally, we expect to adopt the optional transition practical expedient allowing the entity not to reassess the accounting for land easements that currently exist at the adoption of the lease standard on January 1, 2019. Duke Energy is currently evaluating the financial statement impact of adopting this standard and is continuing to monitor industry implementation issues, including easements, pole attachments and renewable PPAs. Other than an expected increase in assets and liabilities, the ultimate impact of the new standard has not yet been determined. Significant system enhancements, including additional processes and controls, will be required to facilitate the identification, tracking and reporting of potential leases based upon requirements of the new lease standard. Duke Energy has begun the implementation of a third-party software tool to help with the adoption and ongoing accounting under the new standard.

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 statement of cash flows. Under the updated guidance, restricted cash and restricted cash equivalents will be included within beginning-of-period and end-of-period cash and cash equivalents on the statement of cash flows.

For Duke Energy, this guidance is effective for the interim and annual periods beginning January 1, 2018. The guidance will be applied using a retrospective transition method to each period presented. Upon adoption by Duke Energy, the revised guidance will result in a change to the amount of cash and cash equivalents and restricted cash explained when reconciling the beginning-of-period and end-of-period total amounts shown on the Consolidated Statement of Cash Flows. Prior to adoption, the Duke Energy Registrants reflect changes in restricted cash within Cash Flows from Investing Activities and within Cash Flows from Operating Activities on the Consolidated Statement of Cash Flows. As a result of this change, our Cash and cash equivalents balance on the Consolidated Statement of Cash Flows as of December 31, 2017 will change by $147 million.

Retirement Benefits. In March 2017, the FASB issued revised accounting guidance for the presentation of net periodic costs related to benefit plans. Current GAAP permits the aggregation of all the components of net periodic costs on the Consolidated Statement of Operations and does not require the disclosure of the location of net periodic costs on the Consolidated Statement of Operations. Under the amended guidance, the service cost component of net periodic costs must be included within Operating Income within the same line as other compensation expenses. All other components of net periodic costs must be 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 current GAAP, which permits all components of net periodic costs to be capitalized. These amendments should be applied retrospectively for the presentation of the various components of net periodic costs and prospectively for the change in eligible costs to be capitalized. The guidance allows for a practical expedient that permits a company to use amounts disclosed in prior-period financial statements as the estimation basis for applying the retrospective presentation requirements.

For Duke Energy, this guidance is effective for interim and annual periods beginning January 1, 2018. Duke Energy currently presents the total non-capitalized net periodic costs within Operation, maintenance and other on the Consolidated Statement of Operations. The adoption of this guidance will result 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 intends to utilize the practical expedient for retrospective presentation. The change in net periodic costs eligible for capitalization is applicable prospectively. Since Duke Energy's service cost component is expected to be greater than the total net periodic costs, the change will result in increased capitalization of net periodic costs, higher Operation, maintenance and other and higher Other income and expenses. The resulting impact to Duke Energy is expected to be an immaterial increase in Net Income resulting from the limitation of eligible capitalization of net periodic costs to the service cost component, which is larger than the total net periodic costs.

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.

Purchase Price Allocation

The purchase price allocation of the Piedmont acquisition is as follows:

(in millions)	
Current assets	$ 497
Property, plant and equipment, net	4,714
Goodwill	3,353
Other long-term assets	804
Total assets	9,368
Current liabilities, including current maturities of long-term debt	576
Long-term liabilities	1,790
Long-term debt	2,002
Total liabilities	4,368
Total purchase price	$ 5,000

The fair value of Piedmont's assets and liabilities was determined based on significant estimates and assumptions that are judgmental in nature, including the amount and timing of projected future cash flows, discount rates reflecting risk inherent in the future cash flows and market prices of long-term debt.

The majority of Piedmont's operations are subject to the rate-setting authority of the NCUC, the PSCSC and the TPUC and are accounted for pursuant to accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for Piedmont's regulated operations provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. Thus, the fair value of Piedmont's assets and liabilities subject to these rate-setting provisions approximates the pre-acquisition carrying values and does not reflect any net valuation adjustments.

The significant assets and liabilities for which valuation adjustments were reflected within the purchase price allocation include the acquired equity method investments and long-term debt. The difference between the fair value and the pre-merger carrying values of long-term debt for regulated operations was recorded as a regulatory asset.

The excess of the purchase price over the fair value of Piedmont's assets and liabilities on the acquisition date was recorded as goodwill. The goodwill reflects the value paid by Duke Energy primarily for establishing a broader, long-term strategic natural gas infrastructure growth platform, an improved risk profile and expected synergies resulting from the combined entities.

Under Securities and Exchange Commission (SEC) regulations, Duke Energy elected not to apply push down accounting to the stand-alone Piedmont financial statements.

Accounting Charges Related to the Acquisition

Duke Energy incurred pretax non-recurring transaction and integration costs associated with the acquisition of $103 million, $439 million and $9 million for the years ended December 31, 2017, 2016 and 2015, respectively. Amounts recorded on the Consolidated Statements of Operations in 2017 were primarily system integration costs of $71 million 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. A $7 million charge was recorded within Impairment Charges, with the remaining $64 million recorded within Operation, maintenance and other.

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.

The majority of transition and integration activities are expected to be 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 non-recurring transaction and integration costs incurred by Duke Energy and Piedmont were $279 million and $19 million for the years ended December 31, 2016, and 2015, respectively.

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.

	Years Ended December 31,	
(in millions)	**2016**	**2015**
Operating Revenues	**$ 23,504**	$ 23,570
Net Income Attributable to Duke Energy Corporation	**2,442**	2,877

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.

Acquisition Related Financings and Other Matters

Duke Energy financed the Piedmont acquisition with a combination of debt and equity issuances and other cash sources, including:

- $3.75 billion of long-term debt issued in August 2016.
- $750 million borrowed under the $1.5 billion short-term loan facility in September 2016, which was repaid in December 2016.
- 10.6 million shares of common stock issued in October 2016 for net cash proceeds of approximately $723 million.

The $4.9 billion senior unsecured bridge financing facility (Bridge Facility) with Barclays Capital, Inc. (Barclays) was terminated following the issuance of the long-term debt. For additional information related to the debt and equity issuances, see Notes 6 and 18, respectively. For additional information regarding Duke Energy's and Piedmont's joint investment in Atlantic Coast Pipeline, LLC (ACP), see Note 4.

DISPOSITIONS

For the year ended December 31, 2017, the Loss from Discontinued Operations, net of tax, was immaterial. The following table summarizes the (Loss) Income from Discontinued Operations, net of tax recorded on Duke Energy's Consolidated Statements of Operations for the years ended December 31, 2016, and 2015:

	Years Ended December 31,	
(in millions)	**2016**	**2015**
International Energy Disposal Group	$ (534)	$ 157
Midwest Generation Disposal Group	36	33
Other[(a)]	90	(13)
(Loss) Income from Discontinued Operations, net of tax	$ (408)	$ 177

(a) Relates to previously sold businesses not related to the Disposal Groups. The amount for 2016 represents an income tax benefit resulting from immaterial out of period deferred tax liability adjustments. The amount for 2015 includes indemnifications provided for certain legal, tax and environmental matters and foreign currency translation adjustments.

2016 Sale of International Energy

In February 2016, Duke Energy announced it had initiated a process to divest its International Energy businesses, excluding the equity method investment in NMC (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 Duke Energy holding company (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 years ended December 31, 2016, and 2015, which are included in (Loss) Income from Discontinued Operations, net of tax in Duke Energy's Consolidated Statements of Operations.

	Years Ended December 31,	
(in millions)	**2016**	**2015**
Operating Revenues	$ 988	$ 1,088
Fuel used in electric generation and purchased power	227	306
Cost of natural gas	43	53
Operation, maintenance and other	341	334
Depreciation and amortization[(a)]	62	92
Property and other taxes	15	7
Impairment charges [(b)]	194	13
(Loss) Gains on Sales of Other Assets and Other, net	(3)	6
Other Income and Expenses, net	58	23
Interest Expense	82	85
Pretax loss on disposal[(c)]	(514)	—
(Loss) Income before income taxes[(d)]	(435)	227
Income tax expense[(e)(f)]	99	70
(Loss) Income from discontinued operations of the International Disposal Group	$ (534)	$ 157

(a) Upon meeting the criteria for assets held for sale, beginning in the fourth quarter of 2016 depreciation expense was 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) Income attributable to Duke Energy Corporation was $(445) million and $221 million for the years ended December 31, 2016 and 2015, respectively.
(e) 2016 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) 2016 amount includes an income tax benefit of $95 million. See Note 22, "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.

	Years Ended December 31,	
(in millions)	**2016**	**2015**
Cash flows provided by (used in):		
Operating activities	**$ 204**	$ 248
Investing activities	**(434)**	177

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, totaling approximately $78 million. Duke Energy has not recorded any other liabilities, contingent liabilities or indemnifications related to the International Disposal Group.

2015 Midwest Generation Exit

Duke Energy, through indirect subsidiaries, completed the sale of the Midwest Generation Disposal Group to a subsidiary of Dynegy on April 2, 2015, for approximately $2.8 billion in cash. The nonregulated Midwest generation business included generation facilities with approximately 5,900 MW of owned capacity located in Ohio, Pennsylvania and Illinois. On April 1, 2015, prior to the sale, Duke Energy Ohio distributed its indirect ownership interest in the nonregulated Midwest generation business to a subsidiary of Duke Energy Corporation.

Duke Energy utilized a revolving credit agreement (RCA) to support the operations of the nonregulated Midwest generation business. Duke Energy Ohio had a power purchase agreement with the Midwest Generation Disposal Group for a portion of its standard service offer (SSO) supply requirement. The agreement and the SSO expired in May 2015.

The results of operations of the Midwest Generation Disposal Group prior to the date of sale are classified as discontinued operations in the accompanying Consolidated Statements of Operations. Interest expense associated with the RCA was allocated to discontinued operations. No other interest expense related to corporate level debt was allocated to discontinued operations. Certain immaterial costs that were eliminated as a result of the sale remained in continuing operations. The following table summarizes the Midwest Generation Disposal Group activity recorded within discontinued operations.

	Duke Energy		Duke Energy Ohio	
	Years Ended December 31,		Years Ended December 31,	
(in millions)	2016	2015	2016	2015
Operating Revenues	$ —	$ 543	$ —	$ 412
Pretax Loss on disposal[a]	—	(45)	—	(52)
Income (loss) before income taxes[b]	$ —	$ 59	$ —	$ 44
Income tax (benefit) expense[c]	(36)	26	(36)	21
Income (loss) from discontinued operations	$ 36	$ 33	$ 36	$ 23

(a) The Loss on disposal includes impairments recorded to adjust the carrying amount of the assets to the estimated fair value of the business, based on the selling price to Dynegy less cost to sell.

(b) 2015 amounts include the impact of an $81 million charge for the settlement agreement reached in a lawsuit related to the Midwest Generation Disposal Group. Refer to Note 5 for further information about the lawsuit.

(c) 2016 amounts result from immaterial out of period deferred tax liability adjustments.

3. BUSINESS SEGMENTS

Operating 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 corporate interest expense, unallocated corporate costs, contributions to the Duke Energy Foundation and the operations of Duke Energy’s wholly owned captive insurance subsidiary, Bison Insurance Company Limited (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, 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 Cuts and Jobs Act (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. Refer to 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. Refer to Note 19 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 investments expenditures related to the International Disposal Group. Gas Utilities and Infrastructure includes the Piedmont acquisition of $5 billion. Refer to Note 2 for more information on the Piedmont acquisition.

	Year Ended December 31, 2015						
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total Reportable Segments	Other	Eliminations	Total
Unaffiliated Revenues	$ 21,489	$ 536	$ 286	$ 22,311	$ 60	$ —	$ 22,371
Intersegment Revenues	32	5	—	37	75	(112)	—
Total Revenues	$ 21,521	$ 541	$ 286	$ 22,348	$ 135	$ (112)	$ 22,371
Interest Expense	$ 1,074	$ 25	$ 44	$ 1,143	$ 393	$ (9)	$ 1,527
Depreciation and amortization	2,735	79	104	2,918	135	—	3,053
Equity in (losses) earnings of unconsolidated affiliates	(2)	1	(6)	(7)	76	—	69
Income tax expense (benefit)	1,602	44	(128)	1,518	(262)	—	1,256
Segment income (loss) [a][b][c]	2,819	73	52	2,944	(299)	—	2,645
Add back noncontrolling interest component							9
Income from discontinued operations, net of tax[d]							177
Net income							$ 2,831
Capital investments expenditures and acquisitions[e]	$ 6,852	$ 234	$ 1,019	$ 8,105	$ 258	$ —	$ 8,363
Segment assets[f]	109,097	2,637	3,861	115,595	5,373	188	121,156

(a) Electric Utilities and Infrastructure includes an after-tax charge of $58 million related to the Edwardsport settlement. Refer to Note 4 for further information.
(b) Other includes $60 million of after-tax costs to achieve mergers.
(c) Other includes after-tax charges of $77 million related to cost savings initiatives. Refer to Note 19 for further information.
(d) Includes the impact of a settlement agreement reached in a lawsuit related to the Midwest Generation Disposal Group. Refer to Note 5 for further information related to the lawsuit and Note 2 for further information on discontinued operations.
(e) Other includes capital investment expenditures of $45 million related to the International Disposal Group.
(f) Other includes Assets Held for Sale balances related to the International Disposal Group. Refer to Note 2 for further information.

Geographical Information

For the years ended December 31, 2017, 2016 and 2015, all assets and revenues from continuing operations are within the U.S.

Major Customers

For the year ended December 31, 2017, revenues from one customer of Duke Energy Progress are $521 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
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
2015					
Electric Utilities and Infrastructure	$ 18,695	$ 2,014	$ —	$ 812	$ 21,521
Gas Utilities and Infrastructure	—	—	546	(5)	541
Commercial Renewables	—	245	—	41	286
Total Reportable Segments	$ 18,695	$ 2,259	$ 546	$ 848	$ 22,348

Duke Energy Ohio

Duke Energy Ohio has two reportable operating 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. It conducts 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, which is primarily comprised of governance costs allocated by its parent, Duke Energy, and revenues and expenses related to Duke Energy Ohio's contractual arrangement to buy power from OVEC's (Ohio Valley Electric Corporation) power plants. See Note 13 for additional information on related party transactions. For the years ended December 31, 2017, 2016 and 2015, all Duke Energy Ohio assets and revenues are within the U.S.

	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

	Year Ended December 31, 2015					
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Total Reportable Segments	Other	Eliminations	Total
Total revenues	$ 1,331	$ 541	$ 1,872	$ 33	$ —	$ 1,905
Interest expense	$ 53	$ 25	$ 78	$ 1	$ —	$ 79
Depreciation and amortization	147	79	226	1	—	227
Income tax expense (benefit)	59	45	104	(23)	—	81
Segment income (loss)	118	73	191	(41)	(1)	149
Income from discontinued operations, net of tax						23
Net income						$ 172
Capital expenditures	$ 264	$ 135	$ 399	$ —	$ —	$ 399
Segment assets	4,534	2,516	7,050	56	(9)	7,097

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)	2017	2016	2017	2016
Regulatory Assets				
AROs – coal ash	**$ 4,025**	$ 3,761	**$ 1,984**	$ 1,830
AROs – nuclear and other	**852**	684	**655**	569
Accrued pension and OPEB	**2,249**	2,387	**906**	882
Retired generation facilities	**480**	534	**386**	422
Debt fair value adjustment	**1,197**	1,313	**—**	—
Net regulatory asset related to income taxes	**—**	894	**—**	231
Storm cost deferrals	**531**	153	**526**	148
Nuclear asset securitized balance, net	**1,142**	1,193	**1,142**	1,193
Hedge costs deferrals	**234**	217	**94**	91
Derivatives – natural gas supply contracts	**142**	187	**—**	—
Demand side management (DSM)/Energy efficiency (EE)	**530**	407	**281**	278
Grid modernization	**39**	65	**—**	—
Vacation accrual	**213**	196	**42**	38
Deferred fuel and purchased power	**507**	156	**349**	111
Nuclear deferral	**119**	226	**35**	134
Post-in-service carrying costs (PISCC) and deferred operating expenses	**366**	413	**38**	42
Transmission expansion obligation	**46**	71	**—**	—
Manufactured gas plant (MGP)	**91**	99	**—**	—
Advanced metering infrastructure (AMI)	**362**	218	**150**	—
NCEMPA deferrals	**53**	51	**53**	51
East Bend deferrals	**45**	32	**—**	—
Deferred pipeline integrity costs	**54**	36	**—**	—
Amounts due from customers	**64**	66	**—**	—
Other	**538**	542	**110**	103
Total regulatory assets	**13,879**	13,901	**6,751**	6,123
Less: current portion	**1,437**	1,023	**741**	401
Total noncurrent regulatory assets	**$ 12,442**	$ 12,878	**$ 6,010**	$ 5,722
Regulatory Liabilities				
Costs of removal	**$ 5,968**	$ 5,613	**$ 2,537**	$ 2,198
ARO – nuclear and other	**806**	461	**—**	—
Net regulatory liability related to income taxes	**8,113**	—	**2,802**	—
Amounts to be refunded to customers	**10**	45	**—**	—
Storm reserve	**20**	83	**—**	60
Accrued pension and OPEB	**146**	174	**—**	—
Deferred fuel and purchased power	**47**	192	**1**	81

Other	**622**	722	**179**	245
Total regulatory liabilities	**15,732**	7,290	**5,519**	2,584
Less: current portion	**402**	409	**213**	189
Total noncurrent regulatory liabilities	**$ 15,330**	$ 6,881	**$ 5,306**	$ 2,395

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 other post-retirement benefit obligations (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 21 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 22 for additional information. Amounts have no immediate impact on rate base as regulatory assets are offset by deferred tax liabilities.

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. Generally recovered within one 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.

Gasification services agreement buyout. The IURC authorized Duke Energy Indiana to recover costs incurred to buy out a gasification services agreement, including carrying costs through 2017.

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 the East End and West End sites through 2019.

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 Generating Station (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, 2017.

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 less than 25 percent of Duke Energy's and Progress Energy's net assets at December 31, 2017.

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 Corp. (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.

All Registrants

Tax Act Impacts

On December 22, 2017, President Trump signed the Tax Act into law, which, among other provisions, reduces the maximum federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. As a result of the Tax Act, the Subsidiary Registrants revalued their deferred tax assets and deferred tax liabilities, as of December 31, 2017, to account for the future impact of lower corporate tax rates on these deferred tax amounts. For the Subsidiary Registrants regulated operations, where the reduction is expected to be accounted for and applied to customers' rates in future commission proceedings, including rate proceedings, the net remeasurement has been deferred as a regulatory liability. Each of the Subsidiary Registrant's regulatory commissions is reviewing the Tax Act to determine the potential impacts on customer rates. Beginning in January 2018, the Subsidiary Registrants will defer the estimated ongoing impacts of the Tax Act that are expected to be returned to customers. See Note 22 for additional information.

Duke Energy Carolinas and Duke Energy Progress

Ash Basin Closure Costs Deferral

On December 30, 2016, Duke Energy Carolinas and Duke Energy Progress filed a joint petition with the NCUC seeking an accounting order authorizing deferral of certain costs incurred in connection with federal and state environmental remediation requirements related to the permanent closure of ash basins and other ash storage units at coal-fired generating facilities that have provided or are providing generation to customers located in North Carolina. Initial comments were received in March 2017, and reply comments were filed on April 19, 2017. The NCUC has consolidated Duke Energy Carolinas' and Duke Energy Progress' coal ash deferral requests into their respective general rate case dockets for decision. See "2017 North Carolina Rate Case" sections below for additional discussion. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter.

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)	**2017**	**2016**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs - coal ash	**$ 1,645**	$ 1,536	(i)	(b)
AROs - nuclear and other	**—**	9		
Accrued pension and OPEB	**410**	481		(j)
Retired generation facilities[c]	**29**	39	X	2023
Net regulatory asset related to income taxes[d]	**—**	484		
Hedge costs deferrals[c]	**109**	93	X	2041
DSM/EE	**210**	122	(h)	(h)
Vacation accrual	**83**	76	(e)	2018
Deferred fuel and purchased power	**140**	—	(f)	2018
Nuclear deferral	**84**	92		2019
PISCC[c]	**35**	70	X	(b)
AMI	**185**	172	X	(b)
Other	**222**	223		(b)
Total regulatory assets	**3,152**	3,397		
Less: current portion	**299**	238		
Total noncurrent regulatory assets	**$ 2,853**	$ 3,159		
Regulatory Liabilities[a]				
Costs of removal[c]	**$ 2,054**	$ 2,015	X	(g)
ARO - nuclear and other	**806**	461		(b)
Net regulatory liability related to income taxes[d]	**3,028**	—		(b)
Storm reserve[c]	**20**	22		(b)
Accrued pension and OPEB	**44**	46		(j)
Deferred fuel and purchased power	**46**	105	(f)	2018
Other	**359**	352		(b)
Total regulatory liabilities	**6,357**	3,001		
Less: current portion	**126**	161		
Total noncurrent regulatory liabilities	**$ 6,231**	$ 2,840		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Includes regulatory liabilities related to the change in the North Carolina tax rate discussed in Note 22.
(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 return on coal ash expenditures for North Carolina and South Carolina retail customers.
(j) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 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 represents an approximate 13.6 percent increase in annual base revenues. The rate increase is driven by capital investments subsequent to the previous base rate case, including grid improvement projects, AMI, investments in customer service technologies, costs of complying with coal combustion residuals (CCR) regulations and the North Carolina Coal Ash Management Act of 2014 (Coal Ash Act) and recovery of costs related to licensing and development of the William States Lee III Nuclear Station (Lee Nuclear Station) discussed below. On January 23, 2018, the North Carolina Public Staff filed testimony recommending an overall rate decrease of approximately $290 million. An evidentiary hearing is scheduled to begin on February 27, 2018, and a decision and revised customer rates are expected by mid-2018. Duke Energy Carolinas cannot predict the outcome of this matter.

FERC Formula Rate Matter

On July 31, 2017, Piedmont Municipal Power Agency (PMPA) filed a complaint with FERC against Duke Energy Carolinas alleging that Duke Energy Carolinas misapplied the formula rate under the purchase power agreement (PPA) between the parties by including regulatory amortization in its rates without FERC approval. Duke Energy Carolinas disagreed with PMPA as it believed it was properly applying its FERC filed rate. 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. Resolution of this matter is not expected to be material.

Lincoln County Combustion Turbine

On December 7, 2017, the NCUC issued an order approving a Certificate of Public Convenience and Necessity (CPCN) for Duke Energy Carolinas' proposed 402-megawatt (MW) simple cycle, advanced combustion turbine natural gas-fueled electric generating unit at its existing Lincoln County site. The CPCN also includes construction of related transmission and natural gas pipeline interconnection facilities. Construction is scheduled to begin in 2018 with an extended commissioning and validation period from 2020-2024 and an estimated commercial operation date in 2024. As a condition of the approval, Duke Energy Carolinas will not seek recovery of costs associated with the project until it is placed into commercial operation.

Advanced Metering Infrastructure Deferral

On July 12, 2016, the PSCSC issued an accounting order for Duke Energy Carolinas to defer the financial effects of depreciation expense incurred for the installation of AMI meters, the carrying costs on the investment at its weighted average cost of capital (WACC) and the carrying costs on the deferred costs at its WACC not to exceed $45 million. The decision also allows Duke Energy Carolinas to continue to depreciate the non-AMI meters to be replaced. Current retail rates will not change as a result of the decision and the ability of interested parties to challenge the reasonableness of expenditures in subsequent proceedings is not limited.

William States Lee Combined Cycle Facility

On April 9, 2014, the PSCSC granted Duke Energy Carolinas and North Carolina Electric Membership Corporation (NCEMC) a Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN) for the construction and operation of a 750-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 estimates a cost to build of $600 million for its share of the facility, including allowance for funds used during construction (AFUDC). The project is expected to be commercially available in the first quarter of 2018. NCEMC will own approximately 13 percent of the project. On July 3, 2014, the South Carolina Coastal Conservation League (SCCL) and Southern Alliance for Clean Energy (SACE) jointly filed a Notice of Appeal with the Court of Appeals of South Carolina (S.C. Court of Appeals) seeking the court's review of the PSCSC's decision, claiming the PSCSC did not properly consider a request related to a proposed solar facility prior to granting approval of the CECPCN. The S.C. Court of Appeals affirmed the PSCSC's decision on February 10, 2016, and on March 24, 2016, denied a request for rehearing filed by SCCL and SACE. On April 21, 2016, SCCL and SACE petitioned the South Carolina Supreme Court for review of the S.C. Court of Appeals decision. On March 24, 2017, the South Carolina Supreme Court denied the request for review, thus concluding the matter.

Lee Nuclear Station

In December 2007, Duke Energy Carolinas applied to the NRC for combined operating licenses (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 result of the COLs being issued.

On March 29, 2017, Westinghouse filed for voluntary Chapter 11 bankruptcy in the U.S. Bankruptcy Court for the Southern District of New York. As part of its 2017 North Carolina Rate Case discussed above, Duke Energy Carolinas is seeking NCUC approval to cancel the development of the Lee Nuclear Station project due to the Westinghouse bankruptcy filing and other market activity and is requesting recovery of incurred licensing and development costs. Duke Energy Carolinas will maintain the license issued by the NRC in December 2016 as an option for potential future development. As of December 31, 2017, Duke Energy Carolinas has incurred approximately $558 million of costs, including AFUDC, related to the project. These project costs are included in Net property, plant and equipment on Duke Energy Carolinas' Consolidated Balance Sheets. 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)	**2017**	**2016**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs - coal ash	**$ 1,975**	$ 1,822	(i)	(b)
AROs - nuclear and other	**359**	275		(c)
Accrued pension and OPEB	**430**	423		(l)
Retired generation facilities	**170**	165	X	2023
Net regulatory asset related to income taxes	**—**	7		(d)
Storm cost deferrals[e]	**150**	148	X	(b)
Hedge costs deferrals	**64**	66		(b)
DSM/EE[f]	**264**	263	(j)	2018
Vacation accrual	**42**	38		2018
Deferred fuel and purchased power	**130**	24	(g)	2018
Nuclear deferral	**35**	38		2019
PISCC and deferred operating expenses	**38**	42	X	2054
AMI	**75**	—		(b)
NCEMPA deferrals	**53**	51	(h)	2042
Other	**74**	69		(b)
Total regulatory assets	**3,859**	3,431		
Less: current portion	**352**	188		
Total noncurrent regulatory assets	**$ 3,507**	$ 3,243		
Regulatory Liabilities[a]				
Costs of removal	**$ 2,122**	$ 1,840	X	(k)
Net regulatory liability related to income taxes	**1,854**	—		(b)
Deferred fuel and purchased power	**1**	64	(g)	2018
Other	**161**	200		(b)
Total regulatory liabilities	**4,138**	2,104		
Less: current portion	**139**	158		
Total noncurrent regulatory liabilities	**$ 3,999**	$ 1,946		

(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) Recovery over the life of the associated assets. Includes regulatory liabilities related to the change in the North Carolina tax rate discussed in Note 22.
(e) South Carolina storm costs are included in rate base.
(f) Included in rate base.

(g) 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.
(h) South Carolina retail allocated costs are earning a return.
(i) Earns a debt return on coal ash expenditures for North Carolina and South Carolina retail customers.
(j) Includes incentives on DSM/EE investments.
(k) Recovered over the life of the associated assets.
(l) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 for additional detail.

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 November 22, 2017, Duke Energy Progress and the North Carolina Public Staff filed an Agreement and Stipulation of Partial Settlement resolving certain portions of the proceeding, pending NCUC approval. Terms of the settlement include 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 Income Statements, principally related to disallowances from rate base of certain projects at the Mayo and Sutton plants. The settlement does not include agreement on portions of the rate case relating to recovery of deferred storm recovery costs and coal ash basin deferred costs, which will be decided by the NCUC separately. Taking into consideration the settled portions and Duke Energy Progress' requested recovery of the non-settled portions, the requested rate increase is reduced to approximately $300 million. An evidentiary hearing ended December 7, 2017, and a decision and revised customer rates are expected in the first quarter of 2018. Duke Energy Progress cannot predict the outcome of this matter.

Storm Cost Deferral Filings

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 March 15, 2017, the NCUC Public Staff filed comments supporting deferral of a portion of Duke Energy Progress' requested amount. Duke Energy Progress filed reply comments on April 12, 2017. On July 10, 2017, the NCUC consolidated Duke Energy Progress' storm deferral request into the Duke Energy Progress rate case docket for decision. See "2017 North Carolina Rate Case" for additional discussion. As of December 31, 2017, Duke Energy Progress has approximately $77 million included in Regulatory assets on its Consolidated Balance Sheets. Duke Energy Progress cannot predict the outcome of this matter.

On December 16, 2016, Duke Energy Progress filed a petition with the PSCSC requesting an accounting order to defer certain costs incurred related to repairs and restoration of service following Hurricane Matthew. The final estimate of incremental operation and maintenance and capital costs was approximately $74 million. In January 2017, the PSCSC approved the deferral request and issued an accounting order. As of December 31, 2017, Duke Energy Progress has approximately $73 million included in Regulatory assets on its Consolidated Balance Sheets.

South Carolina Rate Case

In December 2016, the PSCSC approved a rate case settlement agreement among the ORS (Office of Regulatory Staff), 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 $18.5 million in revenues was effective January 1, 2018. Duke Energy Progress amortized approximately $18.5 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.

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, 2017, 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 underway and construction of these plants began in 2017, with an expected in-service date in late 2019. Duke Energy Progress plans to file for future approvals related to the proposed solar generation and pilot battery storage project.

The carrying value of the 376-MW Asheville coal-fired plant, including associated ash basin closure costs, of $385 million and $492 million are included in Generation facilities to be retired, net on Duke Energy Progress' Consolidated Balance Sheets as of December 31, 2017, and 2016, respectively.

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 were approximately $47 million as of December 31, 2017, 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. The settlement is subject to NCUC approval. Duke Energy Progress cannot predict the outcome of this matter.

Duke Energy Florida

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2017**	**2016**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs - coal ash[c]	**$ 9**	$ 8	X	(b)
AROs - nuclear and other[c]	**296**	294	X	(b)
Accrued pension and OPEB[c]	**476**	458	X	(h)
Retired generation facilities[c]	**216**	257	X	(b)
Net regulatory asset related to income taxes[c]	**—**	224	X	(d)
Storm cost deferrals[c]	**376**	—	(f)	2021
Nuclear asset securitized balance, net	**1,142**	1,193		2036
Hedge costs deferrals	**30**	25		2018
DSM/EE[c]	**17**	15	X	2018
Deferred fuel and purchased power[c]	**219**	87	(g)	2019
Nuclear deferral	**—**	96		
AMI[c]	**75**	—	X	2032
Other	**36**	36		(b)
Total regulatory assets	**2,892**	2,693		
Less: current portion	**389**	213		
Total noncurrent regulatory assets	**$ 2,503**	$ 2,480		
Regulatory Liabilities[a]				
Costs of removal[c]	**$ 415**	$ 358	(e)	(b)
Net regulatory liability related to income taxes[c]	**948**	—		(b)
Storm reserve[c]	**—**	60		
Deferred fuel and purchased power[c]	**—**	17	(g)	
Other	**18**	44		(b)
Total regulatory liabilities	**1,381**	479		
Less: current portion	**74**	31		
Total noncurrent regulatory liabilities	**$ 1,307**	$ 448		

(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) Certain costs earn a return.
(f) Earns a debt return/interest once collections begin.
(g) Earns commercial paper rate.
(h) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 for additional detail.

Storm Restoration Cost Recovery

In September 2017, Duke Energy Florida’s service territory suffered significant damage from Hurricane Irma, resulting in approximately 1.3 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 Hurricanes Irma and Nate and to replenish the storm reserve. The estimated recovery amount is approximately $513 million to be recovered over a three-year period beginning in March 2018, subject to true up, which includes reestablishment of a $132 million storm reserve. At December 31, 2017, Duke Energy Florida's Consolidated Balance Sheets included approximately $376 million of recoverable costs under the FPSC's storm rule in Regulatory assets within Other Noncurrent Assets related to storm recovery. On February 6, 2018, the FPSC approved Duke Energy Florida's motion to approve a stipulation that would apply tax savings resulting from the Tax Act toward storm costs in lieu of implementing a storm surcharge.

2017 Second Revised and Restated Settlement Agreement

On November 20, 2017, the FPSC issued an order to approve the 2017 Second Revised and Restated Settlement Agreement (2017 Settlement) filed by Duke Energy Florida. The 2017 Settlement replaces and supplants the 2013 Settlement. The 2017 Settlement extends the base rate case stay-out provision from the 2013 Settlement through the end of 2021 unless actual or projected return on equity falls below 9.5 percent; however, Duke Energy Florida is allowed a multiyear increase to its base rates of $67 million per year in 2019, 2020 and 2021, as well as base rate increases for solar generation. In addition to carrying forward the provisions contained in the 2013 Settlement related to the Crystal River 1 and 2 coal units discussed below and future generation needs in Florida, the 2017 Settlement contains provisions related to future investments in solar and renewable energy technology, future investments in AMI technology as well as recovery of existing meters, impacts of the Tax Act, an electric vehicle charging station pilot program and the termination of the proposed Levy Nuclear Project discussed below. As part of the 2017 Settlement, Duke Energy Florida will not move forward with building the Levy nuclear plant and recorded a pretax impairment charge of approximately $135 million in 2017 to write off all unrecovered Levy Nuclear Project costs, including the COL. As a result of the 2017 Settlement, Duke Energy Florida transferred $75 million to a regulatory asset for the net book value of existing meter technology, which will be recovered over a 15-year period.

The 2017 Settlement includes provisions to recover 2017 under-recovered fuel costs of approximately $196 million over a 24-month period beginning in January 2018. On September 1, 2017, Duke Energy Florida submitted Alternate 2018 Fuel and Capacity clause projection filings consistent with the terms of the 2017 Settlement. The updated capacity filing reflects the removal of all Levy costs. The FPSC approved Duke Energy Florida's 2018 Alternate projection filings on October 25, 2017.

Hines Chiller Uprate Project

On February 2, 2017, Duke Energy Florida filed a petition seeking approval to include in base rates the revenue requirement for a Chiller Uprate Project (Uprate Project) at the Hines Energy Complex. The Uprate Project was placed into service in March 2017 at a cost of approximately $150 million. The annual retail revenue requirement is approximately $19 million. On March 28, 2017, the FPSC issued an order approving the revenue requirement, which was included in base rates for the first billing cycle of April 2017.

Citrus County Combined Cycle Facility

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. On May 5, 2015, the Florida Department of Environmental Protection approved Duke Energy Florida's Site Certification Application. The project has received all required permits and approvals and construction began in October 2015. The facility is expected to be commercially available in 2018 at an estimated cost of $1.5 billion, including AFUDC. The plant will receive natural gas from the Sabal Trail Transmission, LLC (Sabal Trail) pipeline discussed below.

Purchase of Osprey Energy Center

Duke Energy Florida received a Civil Investigative Demand from the Department of Justice (DOJ) related to alleged violation of the waiting period for the Hart-Scott-Rodino Antitrust Improvements Act of 1976 related to the purchase of the Osprey Energy Center, LLC, which was completed in January 2017. The DOJ alleged Duke Energy Florida assumed operational control of the Osprey Plant before the waiting period expiration on February 27, 2015. On January 17, 2017, Duke Energy Florida entered into a stipulation agreement to settle with the DOJ for $600,000 without admission of liability. On January 18, 2017, the DOJ filed a complaint and the stipulation in the U.S. District Court for the District of Columbia, which was approved by the court. A final order dismissing the case was entered in April 2017.

Crystal River Unit 3

In December 2014, the FPSC approved Duke Energy Florida's decision to construct an independent spent fuel storage installation (ISFSI) for the retired Crystal River Unit 3 nuclear plant and approved Duke Energy Florida's request to defer amortization of the ISFSI pending resolution of litigation against the federal government as a result of the Department of Energy's breach of its obligation to accept spent nuclear fuel. The return rate is based on the currently approved AFUDC rate with a return on equity of 7.35 percent, or 70 percent of the currently approved 10.5 percent. The return rate is subject to change if the return on equity changes in the future. In September 2016, the FPSC approved an amendment to the 2013 Settlement authorizing recovery of the ISFSI through the Capacity Cost Recovery Clause. Through December 31, 2017, Duke Energy Florida has deferred approximately $113 million for recovery associated with building the ISFSI. See Note 5 for additional information on spent nuclear fuel litigation.

The regulatory asset associated with the original Crystal River Unit 3 power uprate project will continue to be recovered through the NCRC over an estimated seven-year period that began in 2013 with a remaining uncollected balance of $87 million at December 31, 2017.

Crystal River Unit 3 Regulatory Asset

On September 15, 2015, the FPSC approved Duke Energy Florida's motion for approval of a settlement agreement with intervenors to reduce the value of the projected Crystal River Unit 3 regulatory asset to be recovered to $1.283 billion as of December 31, 2015. An impairment charge of $15 million was recognized in 2015 to adjust the regulatory asset balance. In November 2015, the FPSC issued a financing order approving Duke Energy Florida’s request to issue nuclear asset-recovery bonds to finance its unrecovered regulatory asset related to Crystal River Unit 3 through a wholly owned special purpose entity. Nuclear asset-recovery bonds replace the base rate recovery methodology authorized by the 2013 Settlement and result in a lower rate impact to customers with a recovery period of approximately 20 years.

Pursuant to provisions in Florida Statutes and the FPSC financing order, in 2016, Duke Energy Florida formed Duke Energy Florida Project Finance, LLC (DEFPF), a wholly owned, bankruptcy remote special purpose subsidiary for the purpose of issuing nuclear asset-recovery bonds. In June 2016, DEFPF issued $1,294 million aggregate principal amount of senior secured bonds (nuclear asset-recovery bonds) to finance the recovery of Duke Energy Florida's Crystal River 3 regulatory asset.

In connection with this financing, net proceeds to DEFPF of approximately $1,287 million, after underwriting costs, were used to acquire nuclear asset-recovery property from Duke Energy Florida and to pay transaction related expenses. The nuclear asset-recovery property includes the right to impose, bill, collect and adjust a non-bypassable nuclear asset-recovery charge, to be collected on a per kilowatt-hour basis, from all Duke Energy Florida retail customers until the bonds are paid in full. Duke Energy Florida began collecting the nuclear asset-recovery charge on behalf of DEFPF in customer rates in July 2016.

See Note 17 for additional information.

Levy Nuclear Project

On July 28, 2008, Duke Energy Florida applied to the NRC for COLs for two Westinghouse AP1000 reactors at Levy (Levy Nuclear Project). In 2008, the FPSC granted Duke Energy Florida’s petition for an affirmative Determination of Need and related orders requesting cost recovery under Florida’s nuclear cost-recovery rule, together with the associated facilities, including transmission lines and substation facilities. In October 2016, the NRC issued COLs for the proposed Levy Nuclear Plant Units 1 and 2. Duke Energy Florida is not required to build the nuclear reactors as a result of the COLs being issued.

On January 28, 2014, Duke Energy Florida terminated the Levy engineering, procurement and construction agreement (EPC). Duke Energy Florida may be required to pay for work performed under the EPC. Duke Energy Florida recorded an exit obligation in 2014 for the termination of the EPC. This liability was recorded within Other in Other Noncurrent Liabilities with an offset primarily to Regulatory assets on the Consolidated Balance Sheets. Duke Energy Florida is allowed to recover reasonable and prudent EPC cancellation costs from its retail customers. On May 1, 2017, Duke Energy Florida filed a request with the FPSC to recover approximately $82 million of Levy Nuclear Project costs from retail customers in 2018. As part of the 2017 Settlement discussed above, Duke Energy Florida is no longer seeking recovery of costs related to the Levy Nuclear Project and the ongoing Westinghouse litigation discussed in Note 5. All remaining Levy Nuclear Project issues have been resolved.

Crystal River 1 and 2 Coal Units

Duke Energy Florida has evaluated Crystal River 1 and 2 coal units for retirement in order to comply with certain environmental regulations. Based on this evaluation, those units are expected to be retired by the end of 2018. Once those units are retired Duke Energy Florida will continue recovery of existing annual depreciation expense through the end of 2020. Beginning in 2021, Duke Energy Florida will be allowed to recover any remaining net book value of the assets from retail customers through the Capacity Cost Recovery Clause.

Duke Energy Ohio

Regulatory Assets and Liabilities

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

(in millions)	December 31, 2017	December 31, 2016	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs - coal ash	**$ 17**	$ 12	X	(b)
Accrued pension and OPEB	**139**	135		(g)
Net regulatory asset related to income taxes[c]	**—**	63		(d)
Storm cost deferrals	**5**	5		(b)
Hedge costs deferrals	**6**	7		(b)
DSM/EE	**18**	6	(f)	(e)
Grid modernization	**39**	65	X	(e)
Vacation accrual	**5**	4		2018
Deferred fuel and purchased power	**—**	5		
PISCC and deferred operating expenses[c]	**19**	20	X	2083
Transmission expansion obligation	**50**	71		(e)
MGP	**91**	99		(b)
AMI	**6**	—		(b)
East Bend deferrals	**45**	32	X	(b)
Deferred pipeline integrity costs	**12**	7	X	(b)
Other	**42**	26		(b)
Total regulatory assets	**494**	557		
Less: current portion	**49**	37		
Total noncurrent regulatory assets	**$ 445**	$ 520		
Regulatory Liabilities[a]				
Costs of removal	**$ 189**	$ 212		(d)
Net regulatory liability related to income taxes	**688**	—		(b)
Accrued pension and OPEB	**16**	19		(g)
Deferred fuel and purchased power	**—**	6		
Other	**34**	20		(b)
Total regulatory liabilities	**927**	257		
Less: current portion	**36**	21		
Total noncurrent regulatory liabilities	**$ 891**	$ 236		

(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 21 for additional detail.

Duke Energy Kentucky 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. The rate increase is driven by increased investment in utility plant, increased operations and maintenance expenses and recovery of regulatory assets. The application also includes implementation of the Environmental Surcharge Mechanism to recover environmental costs not included in base rates, requests to establish a Distribution Capital Investment Rider to recover incremental costs of specific programs, requests to establish a FERC Transmission Cost Reconciliation Rider to recover escalating transmission costs and modification to the 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 is scheduled to begin on March 6, 2018. Duke Energy Kentucky anticipates that rates will go into effect in mid-April 2018. Duke Energy Kentucky cannot predict the outcome of this matter.

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 electric security plan (ESP). If approved by the PUCO, the term of the ESP would be from June 1, 2018, to May 31, 2024. Terms of the ESP include 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. On February 15, 2018, the procedural schedule was suspended to facilitate ongoing settlement discussions. Duke Energy Ohio cannot predict the outcome of this matter.

Woodsdale Station Fuel System Filing

On June 9, 2015, the FERC ruled in favor of PJM Interconnection, LLC (PJM) on a revised Tariff and Reliability Assurance Agreement including implementation of a Capacity Performance (CP) proposal and to amend sections of the Operating Agreement related to generation non-performance. The CP proposal includes performance-based penalties for non-compliance. Duke Energy Kentucky is a Fixed Resource Requirement (FRR) entity, and therefore is subject to the compliance standards through its FRR plans. A partial CP obligation will apply to Duke Energy Kentucky in the delivery year beginning June 1, 2019, with full compliance beginning June 1, 2020. Duke Energy Kentucky has developed strategies for CP compliance investments. On December 21, 2017, the KPSC issued an order approving Duke Energy Kentucky's request for a CPCN to construct an ultra-low sulfur diesel backup fuel system for the Woodsdale Station. The backup fuel system is projected to cost approximately $55 million and is anticipated to be in service prior to the CP compliance deadline of April 2019.

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. The filing seeks to adjust Rider PSR for OVEC costs subsequent to April 1, 2017. Duke Energy Ohio is seeking deferral authority for net costs incurred from April 1, 2017, until the new rates under Rider PSR are put into effect. Various intervenors have filed motions to dismiss or stay the proceeding and Duke Energy Ohio has opposed these filings. See Note 13 for additional discussion of Duke Energy Ohio's ownership interest in OVEC. Duke Energy Ohio cannot predict the outcome of this matter.

East Bend Coal Ash Basin Filing

On December 2, 2016, Duke Energy Kentucky filed with the KPSC a request for a CPCN for construction projects necessary to close and repurpose an ash basin at the East Bend facility as a result of current and proposed EPA regulations. Duke Energy Kentucky estimated a total cost of approximately $93 million in the filing and expects in-service date by the first quarter of 2021. On June 6, 2017, the KPSC approved the CPCN request.

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 includes 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 February 15, 2018, the procedural schedule was suspended to facilitate ongoing settlement discussions. Duke Energy Ohio expects rates will go into effect the second quarter of 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 in its Ohio service territory to increase system reliability and enable the retirement of older infrastructure. On January 20, 2017, Duke Energy Ohio filed an amended application with the Ohio Power Siting Board for approval of one of two proposed routes. A public hearing was held on June 15, 2017, and an adjudicatory hearing was scheduled to begin September 11, 2017. On August 24, 2017, an administrative law judge (ALJ) granted a request made by Duke Energy Ohio to delay the procedural schedule while it works through various issues related to the pipeline route. If approved, construction of the pipeline extension is expected to be completed before the 2020/2021 winter season. The proposed project involves the installation of a natural gas line and is estimated to cost approximately $110 million, excluding AFUDC.

Advanced Metering Infrastructure

On April 25, 2016, Duke Energy Kentucky filed with the KPSC an application for approval of a CPCN for the construction of advanced metering infrastructure. Duke Energy Kentucky estimates the $49 million project will take two years to complete. Duke Energy Kentucky also requested approval to establish a regulatory asset for the remaining book value of existing meter equipment and inventory to be replaced. Duke Energy Kentucky and the Kentucky attorney general entered into a stipulation to settle matters related to the application. On May 25, 2017, the KPSC issued an order to approve the stipulation with certain modifications. On June 1, 2017, Duke Energy Kentucky filed its acceptance of the modifications. The deployment of AMI meters began in third quarter 2017 and is expected to be completed in early 2019. Duke Energy Ohio has approximately $6 million included in Regulatory assets on its Consolidated Balance Sheets at December 31, 2017, for the book value of existing meter equipment.

Accelerated Natural Gas Service Line Replacement Rider

On January 20, 2015, Duke Energy Ohio filed an application for approval of an accelerated natural gas service line replacement program (ASRP). Under the ASRP, Duke Energy Ohio proposed to replace certain natural gas service lines on an accelerated basis over a 10-year period. Duke Energy Ohio also proposed to complete preliminary survey and investigation work related to natural gas service lines that are customer owned and for which it does not have valid records and, further, to relocate interior natural gas meters to suitable exterior locations where such relocation can be accomplished. Duke Energy Ohio's projected total capital and operations and maintenance expenditures under the ASRP were approximately $240 million. The filing also sought approval of a rider mechanism (Rider ASRP) to recover related expenditures. Duke Energy Ohio proposed to update Rider ASRP on an annual basis. Intervenors opposed the ASRP, primarily because they believe the program is neither required nor necessary under federal pipeline regulation. On October 26, 2016, the PUCO issued an order denying the proposed ASRP. Duke Energy Ohio's application for rehearing of the PUCO decision was denied on May 17, 2017.

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 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 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. 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 electric security plan (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 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. Duke Energy Ohio cannot predict the outcome of the appeals in 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 deadlines for completing the MGP environmental investigation and remediation costs at the MGP sites. For the property known as the East End site, the PUCO order established a deadline of December 31, 2016, which was subsequently extended to December 31, 2019. In January 2017, intervening parties filed for rehearing of the PUCO's decision. On February 8, 2017, the PUCO denied the rehearing request. As of December 31, 2017, Duke Energy Ohio had approximately, $35 million included in Regulatory assets on the Consolidated Balance Sheets for future remediation costs expected to be incurred at the East End site.

Regional Transmission Organization Realignment

Duke Energy Ohio, including Duke Energy Kentucky, transferred control of its transmission assets from MISO to PJM Interconnection, LLC (PJM), effective December 31, 2011. The PUCO approved a settlement related to Duke Energy Ohio’s recovery of certain costs of the Regional Transmission Organization (RTO) realignment via a non-bypassable rider. Duke Energy Ohio is allowed to recover all MISO Transmission Expansion Planning (MTEP) costs, including but not limited to Multi Value Project (MVP) costs, directly or indirectly charged to Ohio customers. Duke Energy Ohio also agreed to vigorously defend against any charges for MVP projects from MISO. 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, excluding MVP, recorded within Other in Current liabilities and Other in 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, 2017, and 2016, $50 million and $71 million are recorded in Regulatory assets on Duke Energy Ohio's Consolidated Balance Sheets, respectively.

(in millions)	December 31, 2016	Provisions/ Adjustments	Cash Reductions	December 31, 2017
Duke Energy Ohio	$ 90	$ (20)	$ (4)	$ 66

MVP. MISO approved 17 MVP proposals prior to Duke Energy Ohio’s exit from MISO on December 31, 2011. Construction of these projects is expected to continue through 2020. Costs of these projects, including operating and maintenance costs, property and income taxes, depreciation and an allowed return, are allocated and billed to MISO transmission owners.

On December 29, 2011, MISO filed a tariff with the FERC providing for the allocation of MVP costs to a withdrawing owner based on monthly energy usage. The FERC set for hearing (i) whether MISO’s proposed cost allocation methodology to transmission owners who withdrew from MISO prior to January 1, 2012, is consistent with the tariff at the time of their withdrawal from MISO and, (ii) if not, what the amount of and methodology for calculating any MVP cost responsibility should be. In 2012, MISO estimated Duke Energy Ohio’s MVP obligation over the period from 2012 to 2071 at $2.7 billion, on an undiscounted basis. On July 16, 2013, a FERC Administrative Law Judge (ALJ) issued an initial decision. Under this initial decision, Duke Energy Ohio would be liable for MVP costs. Duke Energy Ohio filed exceptions to the initial decision, requesting FERC to overturn the ALJ’s decision.

On October 29, 2015, the FERC issued an order reversing the ALJ's decision. The FERC ruled the cost allocation methodology is not consistent with the MISO tariff and that Duke Energy Ohio has no liability for MVP costs after its withdrawal from MISO. On May 19, 2016, the FERC denied the request for rehearing filed by MISO and the MISO Transmission Owners. On July 15, 2016, the MISO Transmission Owners filed a petition for review with the U.S. Court of Appeals for the Sixth Circuit. On June 21, 2017, a three-judge panel affirmed FERC's 2015 decision holding that Duke Energy Ohio has no liability for the cost of the MVP projects constructed after Duke Energy Ohio's withdrawal from MISO. MISO did not file further petitions for review and this matter is now final.

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.

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2017**	**2016**	**a Return**	**Period Ends**
Regulatory Assets[(a)]				
AROs - coal ash	**$ 380**	$ 276		(b)
Accrued pension and OPEB	**197**	222		(g)
Retired generation facilities[(c)]	**65**	73	X	2025
Net regulatory asset related to income taxes	**—**	119		(d)
Hedge costs deferrals	**25**	26		(b)
DSM/EE	**21**	—	(e)	(e)
Vacation accrual	**11**	10		2018
Deferred fuel and purchased power	**18**	40		2018
PISCC and deferred operating expenses[(c)]	**274**	281	X	(b)
Gasification services agreement buyout[(f)]	**—**	8		
AMI[(c)]	**21**	46	X	(b)
Other	**131**	121		(b)
Total regulatory assets	**1,143**	1,222		
Less: current portion	**165**	149		
Total noncurrent regulatory assets	**$ 978**	$ 1,073		
Regulatory Liabilities[(a)]				
Costs of removal	**$ 644**	$ 660		(d)
Net regulatory liability related to income taxes	**998**	—		(b)
Amounts to be refunded to customers	**10**	45		2018
Accrued pension and OPEB	**64**	72		(g)
Other	**31**	11		(b)
Total regulatory liabilities	**1,747**	788		
Less: current portion	**24**	40		
Total noncurrent regulatory liabilities	**$ 1,723**	$ 748		

(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) The IURC authorized Duke Energy Indiana to recover costs incurred to buy out a gasification services agreement, including carrying costs through 2017.
(g) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 for additional detail.

Coal Combustion Residual Plan

On March 17, 2016, Duke Energy Indiana filed with the IURC a request for approval of its first group of federally mandated CCR rule compliance projects (Phase I CCR Compliance Projects) to comply with the EPA's CCR rule. The projects in this Phase I filing are CCR compliance projects, including the conversion of Cayuga and Gibson stations to dry bottom ash handling and related water treatment. Duke Energy Indiana requested timely recovery of approximately $380 million in retail capital costs, including AFUDC, and recovery of incremental operating and maintenance costs under a federal mandate tracker that provides for timely recovery of 80 percent of such costs and deferral with carrying costs of 20 percent of such costs for recovery in a subsequent retail base rate case. On January 24, 2017, Duke Energy Indiana and various intervenors filed a settlement agreement with the IURC. Terms of the settlement include recovery of 60 percent of the estimated CCR compliance construction project capital costs through existing rider mechanisms and deferral of 40 percent of these costs until Duke Energy Indiana's next general retail rate case. The deferred costs will earn a return based on Duke Energy Indiana's long-term debt rate of 4.73 percent until costs are included in retail rates, at which time the deferred costs will earn a full return. Costs are to be capped at $365 million, plus actual AFUDC. Costs above the cap would be considered for recovery in the next rate case. Terms of the settlement agreement also require Duke Energy Indiana to perform certain reporting and groundwater monitoring. On May 24, 2017, the IURC approved the settlement agreement.

Edwardsport Integrated Gasification Combined Cycle Plant

Costs for the Edwardsport Integrated Gasification Combined Cycle (IGCC) Plant are recovered from retail electric customers via a tracking mechanism (IGCC rider) with updates filed by Duke Energy Indiana. The IGCC Plant was placed into commercial operation in June 2013.

On August 24, 2016, the IURC approved a settlement (IGCC Settlement) among Duke Energy Indiana and several intervenors to resolve disputes related to five IGCC riders (the 11th through 15th) and a subdocket to Duke Energy Indiana's fuel adjustment clause. The IGCC settlement resulted in customers not being billed for previously incurred plant operating costs of $87.5 million and payments and commitments from Duke Energy Indiana of $5.5 million for attorneys' fees and consumer programs funding. Duke Energy Indiana recognized pretax impairment and related charges of $93 million in 2015. Additionally, under the IGCC settlement, the recovery of operating and maintenance expenses and ongoing maintenance capital at the plant were subject to certain caps during the years of 2016 and 2017. The IGCC settlement also included a commitment to either retire or stop burning coal by December 31, 2022, at the Gallagher Station. Pursuant to the IGCC settlement, the in-service date used for accounting and ratemaking will remain as June 2013. Remaining deferred costs will be recovered over eight years beginning in 2016 and not earn a carrying cost. As of December 31, 2017, deferred costs related to the project are approximately $152 million and are included in Regulatory assets in Current Assets and Other Noncurrent Assets on Duke Energy Indiana's Consolidated Balance Sheets. Under the IGCC settlement, future IGCC riders will be filed annually with the next filing scheduled for first quarter 2018.

The ninth semi-annual IGCC rider order was appealed by various intervenors and the matter was remanded to the IURC for further proceedings and additional findings on a tax in-service issue. On February 2, 2017, the IURC issued an order upholding the original decision, finding that an estimate of impact on customer rates due to the federal income tax in-service determination was reasonable.

FERC Transmission Return on Equity Complaint

Customer groups have filed with the FERC complaints against 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. This decision may affect the outcome of the complaints against Duke Energy Indiana. Duke Energy Indiana currently believes these matters will not have a material impact on its results of operations, cash flows and financial position.

Grid Infrastructure Improvement Plan

On December 7, 2015, Duke Energy Indiana filed a grid infrastructure improvement plan with an estimated cost of $1.8 billion in response to guidance from IURC orders and the Indiana Court of Appeals decisions related to a new statute. The plan uses a combination of advanced technology and infrastructure upgrades to improve service to customers and provide them with better information about their energy use. It also provides for cost recovery through a transmission and distribution rider (T&D Rider). In March 2016, Duke Energy Indiana entered into a settlement with all parties to the proceeding except the Citizens Action Coalition of Indiana, Inc. The settlement agreement decreased the capital expenditures eligible for timely recovery of costs in the seven-year plan to approximately $1.4 billion, including the removal of an AMI project. Under the settlement, the return on equity to be used in the T&D Rider is 10 percent. The IURC approved the settlement and issued a final order on June 29, 2016. The order was not appealed and the proceeding is concluded.

The settlement agreement provided for deferral accounting for depreciation and post-in-service carrying costs for AMI projects outside the plan. Duke Energy Indiana withdrew its request for a regulatory asset for current meters and will retain any savings associated with future AMI installation until the next retail base rate case, which is required to be filed prior to the end of the plan. During the third quarter of 2016, Duke Energy Indiana decided to implement the AMI project. This decision resulted in a pretax impairment charge related to existing or non-AMI meters of approximately $8 million in 2016, based in part on the requirement to file a base rate case in 2022 under the approved plan. Duke Energy Indiana evaluates the need for rate cases as part of its business planning, based on the outlook of emerging costs, ongoing investment and impact related to the Tax Act enacted in late 2017 and expects to file a rate case prior to the 2022 requirement. As a result, in 2017, Duke Energy Indiana recorded an additional impairment charge of approximately $22 million. As of December 31, 2017, Duke Energy Indiana's remaining net book value of non-AMI meters is approximately $21 million and will be depreciated through July 2020.

Benton County Wind Farm Dispute

On December 16, 2013, Benton County Wind Farm LLC (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. Duke Energy Indiana cannot predict the outcome of this matter.

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)	**2017**	**2016**	**a Return**	**Period Ends**
Regulatory Assets[(a)]				
AROs - other	**$ 15**	$ 14		(d)
Accrued pension and OPEB[(c)]	**91**	166		(f)
Derivatives - gas supply contracts	**142**	187		(e)
Vacation accrual[(c)]	**10**	13		2018
Deferred pipeline integrity costs[(c)]	**42**	36		2018
Amount due from customers	**64**	66	X	(b)
Other	**14**	15		(b)
Total regulatory assets	**378**	497		
Less: current portion	**95**	124		
Total noncurrent regulatory assets	**$ 283**	$ 373		
Regulatory Liabilities[(a)]				
Costs of removal	**$ 544**	$ 528		(d)
Net regulatory liability related to income taxes	**597**	80		(b)
Other	**3**	—		(b)
Total regulatory liabilities	**1,144**	608		
Less: current portion	**3**	—		
Total noncurrent regulatory liabilities	**$ 1,141**	$ 608		

(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 21 for additional detail.

South Carolina Rate Stabilization Adjustment Filing

In June 2017, Piedmont filed with the PSCSC under the South Carolina Rate Stabilization Act its quarterly monitoring report for the 12-month period ending March 31, 2017. The filing included a revenue deficiency calculation and tariff rates in order to permit Piedmont the opportunity to earn the rate of return on equity of 12.6 percent established in its last general rate case. On October 4, 2017, the PSCSC approved a settlement agreement between Piedmont and the SC Office of Regulatory Staff. Terms of the settlement included implementation of rates for the 12-month period beginning November 2017 with a return on equity of 10.2 percent.

North Carolina Integrity Management Rider Filings

In October 2017, Piedmont filed a petition with the NCUC under the Integrity Management Rider (IMR) mechanism to collect an additional $8.9 million in annual revenues, effective December 2017, based on the eligible capital investments closed to integrity and safety projects over the six-month period ending September 30, 2017. On November 28, 2017, the NCUC approved the requested rate adjustment.

In May 2017, Piedmont filed, and the NCUC approved, a petition under the IMR mechanism to collect an additional $11.6 million in annual revenues, effective June 2017, based on the eligible capital investments closed to integrity and safety projects over the six-month period ending March 31, 2017.

Tennessee Integrity Management Rider Filing

In November 2017, Piedmont filed a petition with the TPUC under the IMR mechanism to collect an additional $3.3 million in annual revenues, effective January 2018, based on the eligible capital investments closed to integrity and safety projects over the 12-month period ending October 31, 2017. In January 2018, Piedmont filed an amended computation under the IMR mechanism, revising the proposed increase in annual revenues to approximately $0.4 million based on the decrease in the corporate federal income tax rate effective January 1, 2018. A hearing on this matter is scheduled for March 2018.

OTHER REGULATORY MATTERS

Atlantic Coast Pipeline

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 build and operate the ACP pipeline and holds a leading ownership percentage in ACP of 48 percent. Duke Energy owns a 47 percent interest 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. On September 18, 2015, ACP filed an application with the FERC requesting a CPCN authorizing ACP to construct the pipeline. ACP executed a construction agreement in September 2016. ACP also requested approval of an open access tariff and the precedent agreements it entered into with future pipeline customers. In December 2016, FERC issued a draft Environmental Impact Statement (EIS) indicating that the proposed pipeline would not cause significant harm to the environment or protected populations. The FERC issued the final EIS in July 2017. On October 13, 2017, FERC issued an order approving the CPCN, subject to conditions. On October 16, 2017, ACP accepted the FERC order subject to reserving its right to file a request for rehearing or clarification on a timely basis. On November 9, 2017, ACP filed a request for rehearing on several limited issues. On December 12, 2017, ACP filed an answer to intervenors' request for rehearing of the certificate order and for stay of the certificate order.

In December 2017, West Virginia issued a waiver of the state water quality permit in reliance on the U.S. Army Corps of Engineers national water quality permit and Virginia issued a conditional water quality permit subject to completion of additional studies and stormwater plans. In early 2018, the FERC issued a series of Partial Notices to Proceed which authorized the project to begin limited construction-related activities along the pipeline route. North Carolina issued the state water quality permit in January 2018. The project remains subject to other pending federal and state approvals, which will allow full construction activities to begin. The ACP pipeline project has a targeted in-service date of late 2019.

Due to delays in obtaining the required permits to commence construction and the conditions imposed upon the project by the permits, ACP's project manager estimates the project's pipeline development costs have increased from a range of $5.0 billion to $5.5 billion to a range of $6.0 billion and $6.5 billion, excluding financing costs. Project construction activities, schedule and final costs are still subject to uncertainty due to potential additional permitting delays, construction productivity and other conditions and risks which could result in potential higher project costs and a potential delay in the targeted in-service date.

Sabal Trail Transmission Pipeline

On May 4, 2015, Duke Energy acquired a 7.5 percent ownership interest in Sabal Trail Transmission, LLC (Sabal Trail) 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 Florida Power & Light Company (FP&L), have each contracted to buy pipeline capacity for 25-year initial terms. See Notes 12 and 17 for additional information.

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 one 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 Combined Cycle facility, which remains pending. This request is required to support commissioning and testing activities at the facility.

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 but did not issue the order on remand. 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. The February 6, 2018 motions automatically stay the issuance of the court's mandate until the later of seven days after the court denies the motions or the expiration of any stay granted by the court. Both motions are pending. Sabal Trail will continue to monitor the progress and the impact to the project going forward.

Constitution Pipeline

Duke Energy owns a 24 percent ownership interest in Constitution Pipeline Company, LLC (Constitution). 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.

In December 2014, Constitution received approval from the FERC to construct and operate the proposed pipeline. However, on April 22, 2016, the New York State Department of Environmental Conservation (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. 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. Constitution is currently unable to approximate an in-service date for the project due to the NYDSEC'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. Duke Energy cannot predict the outcome of this matter.

Since April 2016, with the actions of the NYSDEC, Constitution stopped construction and discontinued capitalization of future development costs until the project's uncertainty is resolved.

See Notes 12 and 17 for additional information related to ownership interest and carrying value of the investment.

Progress Energy Merger FERC Mitigation

Following the closing of the Progress Energy merger, outside counsel reviewed Duke Energy’s long-term FERC mitigation plan and discovered a technical error in the calculations. On December 6, 2013, Duke Energy submitted a filing to the FERC disclosing the error and arguing that no additional mitigation is necessary. The city of New Bern filed a protest and requested that FERC order additional mitigation. On October 29, 2014, the FERC ordered that the amount of the stub mitigation be increased from 25 MW to 129 MW. The stub mitigation is Duke Energy’s commitment to set aside for third parties a certain quantity of firm transmission capacity from Duke Energy Carolinas to Duke Energy Progress during summer off-peak hours. The FERC also ordered that Duke Energy operate certain phase shifters to create additional import capability and that such operation be monitored by an independent monitor. The costs to comply with this order are not material. The FERC also referred Duke Energy’s failure to expressly designate the phase shifter reactivation as a mitigation project in the original mitigation plan filing in March 2012 to the FERC Office of Enforcement for further inquiry. In response, and since December 2014, the FERC Office of Enforcement has been conducting a nonpublic investigation of Duke Energy's market power analyses included in the Progress merger filings submitted to FERC. Duke Energy cannot predict the outcome of this investigation.

Potential Coal Plant Retirements

The Subsidiary Registrants periodically file Integrated Resource Plans (IRP) 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. Recent IRPs filed by the Subsidiary Registrants included planning assumptions to potentially retire certain coal-fired generating facilities in Florida and Indiana earlier than their current estimated useful lives primarily because facilities do not have the requisite emission control equipment to meet EPA regulations recently approved or proposed.

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, 2017, 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	$ 163
Progress Energy and Duke Energy Florida		
Crystal River Units 1 and 2[(b)]	873	107
Duke Energy Indiana		
Gallagher Units 2 and 4[(c)]	280	127
Total Duke Energy	1,738	$ 397

(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 Florida expects to retire these coal units by the end of 2018 to comply with environmental regulations.

(c) 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 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 the McGuire Nuclear Station (McGuire) and the Oconee Nuclear Station (Oconee) and operates and has a partial ownership interest in the Catawba Nuclear Station (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 the Robinson Nuclear Plant (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 onsite dry cask storage facility.

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

Nuclear Liability Coverage

The Price-Anderson Act requires owners of nuclear reactors to provide for public nuclear liability protection per nuclear incident up to a maximum total financial protection liability. The maximum total financial protection liability, which is approximately $13.4 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, Duke Energy Progress and Duke Energy Florida have purchased the maximum reasonably available private primary nuclear liability insurance as required by law, which is $450 million per station.

Excess Liability Program

This program provides $13 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 $127 million times the current 102 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 $19 million per year per licensed reactor for each incident. The assessment may be subject to state premium taxes.

Nuclear Property and Accidental Outage Coverage

Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida are members of Nuclear Electric Insurance Limited (NEIL), an industry mutual insurance company, which provides property damage, nuclear accident decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. Additionally, NEIL provides accidental outage coverage for 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 $1.83 billion.

Each nuclear facility has accident property damage, 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 and Catawba, $462 million for Brunswick, $448 million for Harris, $434 million for Oconee and $378 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 $146 million, $96 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, 2014	$ 92	$ 10	$ 17	$ 5	$ 12	$ 54	$ 10
Provisions/adjustments	11	1	4	—	4	1	5
Cash reductions	(9)	(1)	(4)	(2)	(2)	(1)	(3)
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**

As of December 31, 2016, October 31, 2016, 2015 and 2014, Piedmont's environmental reserve was $1 million. In 2017, a $1 million provision was recorded, resulting in a reserve balance of $2 million at December 31, 2017.

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	**$ 56**
Duke Energy Carolinas	**19**
Duke Energy Ohio	**30**
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. Duke Energy Carolinas estimates 30,000 to 39,000 tons of ash and 24 million to 27 million gallons of basin water were released into the river. In July 2014, Duke Energy completed remediation work identified by the EPA and continues to cooperate with the EPA's civil enforcement process. Future costs related to the Dan River release, including future state or federal civil enforcement proceedings, future regulatory directives, natural resources damages, future claims or litigation and long-term environmental impact costs, cannot be reasonably estimated at this time.

The North Carolina Department of Environmental Quality (NCDEQ) has historically assessed Duke Energy Carolinas and Duke Energy Progress with Notice of Violations (NOV) 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 L.V. Sutton Combined Cycle Plant (Sutton) and Dan River Steam Station. Duke Energy Carolinas and Duke Energy Progress cannot predict whether the NCDEQ will assess future penalties related to existing unresolved NOVs and if such penalties would be material. See "NCDEQ Notices of Violation" section below for additional discussion.

LITIGATION

Duke Energy

Duke Energy no longer has exposure to litigation matters related to the International Disposal Group as a result of the divestiture of the business in December 2016. See Note 2 for additional information related to the sale of International Energy.

Ash Basin Shareholder Derivative Litigation

Five shareholder derivative lawsuits were filed in Delaware Chancery Court relating to the release at Dan River and to the management of Duke Energy's ash basins. On October 31, 2014, the five lawsuits were consolidated in a single proceeding titled *In Re Duke Energy Corporation Coal Ash Derivative Litigation*. On December 2, 2014, plaintiffs filed a Corrected Verified Consolidated Shareholder Derivative Complaint (Consolidated Complaint). The Consolidated Complaint names as defendants several current and former Duke Energy officers and directors (collectively, the "Duke Energy Defendants"). Duke Energy is named as a nominal defendant.

The Consolidated Complaint alleges the Duke Energy Defendants breached their fiduciary duties by failing to adequately oversee Duke Energy's ash basins and that these breaches of fiduciary duty may have contributed to the incident at Dan River and continued thereafter. The lawsuit also asserts claims against the Duke Energy Defendants for corporate waste (relating to the money Duke Energy has spent and will spend as a result of the fines, penalties and coal ash removal) and unjust enrichment (relating to the compensation and director remuneration that was received despite these alleged breaches of fiduciary duty). The lawsuit seeks both injunctive relief against Duke Energy and restitution from the Duke Energy Defendants. On January 21, 2015, the Duke Energy Defendants filed a Motion to Stay, which the court granted. The stay was lifted on March 24, 2016, after which plaintiffs filed an Amended Verified Consolidated Shareholder Derivative Complaint (Amended Complaint) making the same allegations as in the Consolidated Complaint. The Duke Energy Defendants filed a motion to dismiss the Amended Complaint on June 21, 2016, which was granted by the Court on December 14, 2016. Plaintiffs filed an appeal to the Delaware Supreme Court on January 9, 2017. Oral argument was held on September 27, 2017. On December 15, 2017, the Delaware Supreme Court affirmed the Chancery Court's order of dismissal.

In addition to the above derivative complaints, in 2014, Duke Energy received two shareholder litigation demand letters. The letters alleged that the members of the Board of Directors and certain officers breached their fiduciary duties by allowing the company to illegally dispose of and store coal ash pollutants. One of the letters also alleged a breach of fiduciary duty in the decision-making relating to the leadership changes following the close of the Progress Energy merger in July 2012. By letter dated September 4, 2015, attorneys for the shareholders were informed that, on the recommendation of the Demand Review Committee formed to consider such matters, the Board of Directors concluded not to pursue potential claims against individuals. One of the shareholders, Mitchell Pinsly, sent a formal demand for records and Duke Energy has responded to this request. There was no follow-up after the records were provided; therefore, this matter has been resolved.

On October 30, 2015, shareholder Saul Bresalier filed a shareholder derivative complaint (Bresalier Complaint) in the U.S. District Court for the District of Delaware. The lawsuit alleges that several current and former Duke Energy officers and directors (Bresalier Defendants) breached their fiduciary duties in connection with coal ash environmental issues, the post-merger change in Chief Executive Officer (CEO) and oversight of political contributions. Duke Energy is named as a nominal defendant. The Bresalier Complaint contends that the Demand Review Committee failed to appropriately consider the shareholder's earlier demand for litigation and improperly decided not to pursue claims against the Bresalier Defendants. On March 30, 2017, the court granted Defendants' Motion to Dismiss on the claims relating to coal ash environmental issues and political contributions. As discussed below, a settlement agreement was approved for the merger-related claims in the Bresalier Complaint, and those claims were dismissed. On September 8, 2017, Bresalier filed a notice of appeal to the U.S. Court of Appeals for the Third Circuit (Third Circuit Court) challenging the dismissal of his coal ash and political contribution claims. On January 19 2018, Bresalier filed a stipulation of dismissal, closing this case.

Progress Energy Merger Shareholder Litigation

Duke Energy, the 11 members of the Board of Directors who were also members of the pre-merger Board of Directors (Legacy Duke Energy Directors) and certain Duke Energy officers were defendants in a purported securities class-action lawsuit *(Nieman v. Duke Energy Corporation, et al)*. This lawsuit consolidated three lawsuits originally filed in July 2012. The plaintiffs alleged federal Securities Act of 1933 and Securities Exchange Act of 1934 (Exchange Act) claims based on allegations of materially false and misleading representations and omissions in the Registration Statement filed on July 7, 2011, and purportedly incorporated into other documents, all in connection with the post-merger change in CEO. On August 15, 2014, the parties reached an agreement in principle to settle the litigation. On March 10, 2015, the parties filed a Stipulation of Settlement and a Motion for Preliminary Approval of the Settlement. Under the terms of the agreement, Duke Energy agreed to pay $146 million to settle the claim. On April 22, 2015, Duke Energy made a payment of $25 million into the settlement escrow account. The remainder of $121 million was paid by insurers into the settlement escrow account. The final order approving the settlement was issued on November 2, 2015, thus closing the matter.

On May 31, 2013, the Delaware Chancery Court consolidated four shareholder derivative lawsuits filed in 2012. The Court also appointed a lead plaintiff and counsel for plaintiffs and designated the case as *In Re Duke Energy Corporation Derivative Litigation* (Merger Chancery Litigation). The lawsuit names as defendants the Legacy Duke Energy Directors. Duke Energy is named as a nominal defendant. The case alleges claims for breach of fiduciary duties of loyalty and care in connection with the post-merger change in CEO.

Two shareholder Derivative Complaints, filed in 2012 in federal district court in Delaware, were consolidated as *Tansey v. Rogers, et al.* The case alleges claims against the Legacy Duke Energy Directors for breach of fiduciary duty and waste of corporate assets, as well as claims under Section 14(a) and 20(a) of the Exchange Act. Duke Energy is named as a nominal defendant. On December 21, 2015, Plaintiff filed a Consolidated Amended Complaint asserting the same claims contained in the original complaints.

The Legacy Duke Energy Directors have reached an agreement-in-principle to settle the Merger Chancery Litigation, conditioned on dismissal as well, of the *Tansey v. Rogers, et al* case and the merger related claims in the Bresalier Complaint discussed above, which was approved by the Delaware Chancery Court on July 13, 2017. The entire settlement amount was funded by insurance. The settlement amount, less court-approved attorney fees, totaled $20 million and was paid to Duke Energy in 2017.

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 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. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter.

NCDEQ Notice of Violation

On February 8, 2016, the NCDEQ assessed a penalty of approximately $6.8 million, including enforcement costs, against Duke Energy Carolinas related to stormwater pipes and associated discharges at the Dan River Steam Station. Duke Energy Carolinas recorded a charge in December 2015 for this penalty. In March 2016, Duke Energy Carolinas filed an appeal of this penalty. On September 23, 2016, Duke Energy Carolinas entered into a settlement agreement with the NCDEQ, without admission of liability, under which Duke Energy Carolinas agreed to a payment of $6 million to resolve allegations underlying the asserted civil penalty related to the Dan River coal ash release and a March 4, 2016, NOV alleging unpermitted discharges at the facility.

NCDEQ State Enforcement Actions

In the first quarter of 2013, Southern Environmental Law Center (SELC) sent notices of intent to sue Duke Energy Carolinas and Duke Energy Progress related to alleged Clean Water Act (CWA) violations from coal ash basins at two of their 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 their remaining 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 to challenge the trial court's order. The parties were unable to reach an agreement at mediation in April 2017. The parties submitted briefs to the court on remaining issues to be tried and a ruling is pending. On August 22, 2017, Duke Energy Carolinas and Duke Energy Progress filed a Petition for Discretionary Review, requesting the North Carolina Supreme Court to accept the appeal. On August 24, 2017, SELC filed a motion to dismiss the appeal. Duke Energy Carolinas' and Duke Energy Progress' opening appellate briefs were filed on October 12, 2017, and briefing is now complete. Argument was held on February 8, 2018.

It is not possible to predict any liability or estimate any damages Duke Energy Carolinas or Duke Energy Progress might incur in connection with these matters.

Federal Citizens Suits

On June 13, 2016, the Roanoke River Basin Association (RRBA) filed a federal citizen suit in the Middle District of North Carolina alleging unpermitted discharges to surface water and groundwater violations at the Mayo Plant. On August 19, 2016, Duke Energy Progress filed a Motion to Dismiss. On April 26, 2017, the court entered an order dismissing four of the claims in the federal citizen suit. Two claims relating to alleged violations of National Pollutant Discharge Elimination System (NPDES) permit provisions survived the motion to dismiss, and Duke Energy Progress filed its response on May 10, 2017. The parties are engaged in pre-trial discovery. Trial has been scheduled for July 9, 2018.

On March 16, 2017, RRBA served Duke Energy Progress with a Notice of Intent to Sue under the CWA for alleged violations of effluent standards and limitations at the Roxboro Plant. In anticipation of litigation, Duke Energy Progress filed a Complaint for Declaratory Relief in the U.S. District Court for the Western District of Virginia on May 11, 2017, which was subsequently dismissed. 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 and one claim relating to the use of nearby water bodies. The parties are engaged in pre-trial discovery. Trial has been scheduled for October 1, 2018.

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 argued on January 30, 2018.

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.

On December 6, 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 Steam Station (Belews Creek) under the CWA. Duke Energy Carolinas filed a motion to dismiss on February 5, 2018.

It is not possible to predict whether Duke Energy Carolinas or Duke Energy Progress will incur any liability or to estimate the damages, if any, they might incur in connection with these matters.

Five previously filed cases involving the Riverbend, Cape Fear, H.F. Lee, Sutton and Buck plants have been dismissed or settled during 2016.

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 North Carolina Department of Health and Human Services (DHHS). Results of Comprehensive Site Assessments (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. Duke Energy Carolinas and Duke Energy Progress recognized reserves of $19 million and $4 million, respectively.

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. Duke Energy filed its Motion to Dismiss on October 27, 2017, and the hearing is scheduled for March 7, 2018.

It is not possible to estimate the maximum exposure of loss, if any, that may occur in connection with claims which might be made by these residents.

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, 2017, there were 161 asserted claims for non-malignant cases with the cumulative relief sought of up to $42 million and 54 asserted claims for malignant cases with the cumulative relief sought of up to $16 million. Based on Duke Energy Carolinas' experience, it is expected that the ultimate resolution of most of these claims likely will be less than the amount claimed.

Duke Energy Carolinas has recognized asbestos-related reserves of $489 million and $512 million at December 31, 2017, and 2016, 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 the minimum amount of the range of loss for current and future asbestos claims through 2037, are recorded on an undiscounted basis and incorporate anticipated inflation. 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 2037 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 $797 million in excess of the self-insured retention. Receivables for insurance recoveries were $585 million and $587 million at December 31, 2017, and 2016, 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 will recognize the recoveries in the first quarter of 2018. Claims for all periods through 2013 have been resolved. Additional claims will be filed in 2018.

Duke Energy Progress

Gypsum Supply Agreements Matter

On June 30, 2017, CertainTeed Gypsum NC, Inc. (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 seeks an order from the court declaring that the minimum amount of gypsum Duke Energy Progress must provide to CertainTeed under the supply agreement is 50,000 tons per month through 2029. On September 28, 2017, the Court denied CertainTeed's motion for summary judgment. Discovery in the case is underway and a trial date has not been set. In light of the volatility in future production of gypsum, Duke Energy Progress cannot predict the outcome of this matter.

Duke Energy Florida

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 putative class of Duke Energy Florida and FP&L’s customers in Florida. The suit alleges the State of Florida’s nuclear power plant cost recovery statutes (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 U.S. Court of Appeals. The appeal, which has been fully briefed, was heard on August 22, 2017, and a decision is pending. Duke Energy Florida cannot predict the outcome of this appeal.

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 the terminated EPC for Levy as well as a determination by the court of the amounts due to Westinghouse as a result of the termination of the EPC. Duke Energy Florida recognized an exit obligation as a result of the termination of the EPC contract.

On March 31, 2014, Westinghouse filed a lawsuit against Duke Energy Florida in U.S. District Court for the Western District of Pennsylvania. The Pennsylvania lawsuit alleged damages under the EPC 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 on the parties' respective Motions for Summary Judgment, ruling in favor of Westinghouse on a $30 million termination fee claim and dismissing Duke Energy Florida's $54 million refund claim, but stating that Duke Energy Florida could use the refund claim to offset any damages for termination costs. Westinghouse's claim for termination costs was unaffected by this ruling and continued to trial. At trial, Westinghouse reduced its claim for termination costs from $482 million to $424 million. Following a trial on the matter, the court issued its final order in December 2016 denying Westinghouse’s claim for termination costs and re-affirming its earlier ruling in favor of Westinghouse on the $30 million termination fee and Duke Energy Florida’s refund claim. Judgment was entered against Duke Energy Florida in the amount of approximately $34 million, which includes pre-judgment interest. Westinghouse has appealed the trial court's order and Duke Energy Florida has cross-appealed. Duke Energy Florida cannot predict the ultimate outcome of the appeal of the trial court's order.

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. Briefing of the appeal concluded on October 20, 2017. Oral argument in the appeal was originally set for March 2018 but has tentatively been rescheduled to May 2018, due to scheduling conflicts.

Ultimate resolution of these matters could have a material effect on the results of operations, financial position or cash flows of Duke Energy Florida. See discussion of the 2017 Settlement and the Levy Nuclear Project in Note 4 for additional information regarding recovery of costs related to Westinghouse. The 2017 Settlement does not permit recovery of any amounts paid to resolve this contract litigation.

MGP Cost Recovery Action

On December 30, 2011, Duke Energy Florida filed a lawsuit against FirstEnergy Corp. (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 has been fully briefed and argued. Duke Energy Florida cannot predict the outcome of this appeal.

Duke Energy Ohio

Antitrust Lawsuit

In January 2008, four plaintiffs, including individual, industrial and nonprofit customers, filed a lawsuit against Duke Energy Ohio in federal court in the Southern District of Ohio. Plaintiffs alleged Duke Energy Ohio conspired to provide inequitable and unfair price advantages for certain large business consumers by entering into nonpublic option agreements in exchange for their withdrawal of challenges to Duke Energy Ohio's Rate Stabilization Plan implemented in early 2005. In March 2014, a federal judge certified this matter as a class action. Plaintiffs alleged claims of antitrust violations under the federal Robinson Patman Act as well as fraud and conspiracy allegations under the federal Racketeer Influenced and Corrupt Organizations statute and the Ohio Corrupt Practices Act.

During 2015, the parties received preliminary court approval of a settlement agreement. Duke Energy Ohio recorded a litigation settlement reserve of $81 million classified in Other within Current Liabilities on the Consolidated Balance Sheet at December 31, 2015. Duke Energy Ohio also recognized a pretax charge of $81 million in (Loss) Income From Discontinued Operations, net of tax in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2015. The settlement agreement was approved at a federal court hearing on April 19, 2016. Distribution of the settlement checks was approved by the court in January 2017 and all settlement amounts have been paid. See Note 2 for further discussion on the Midwest Generation Exit.

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 and the exit obligation discussed above related to the termination of an EPC contract. Reserves are classified on the Consolidated Balance Sheets in Other within Other Noncurrent Liabilities and Accounts payable 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)	**2017**	**2016**
Reserves for Legal Matters		
Duke Energy	**$ 88**	$ 98
Duke Energy Carolinas	**30**	23
Progress Energy	**55**	59
Duke Energy Progress	**13**	14
Duke Energy Florida	**24**	28
Duke Energy Ohio	**—**	4
Piedmont	**2**	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. Amounts at Duke Energy Ohio were immaterial.

		Minimum Purchase Amount at December 31, 2017						
(in millions)	Contract Expiration	2018	2019	2020	2021	2022	Thereafter	Total
Duke Energy Progress[(a)]	2019-2031	$ 68	$ 68	$ 51	$ 52	$ 30	$ 239	$ 508
Duke Energy Florida[(b)]	2021-2043	357	374	394	378	376	770	2,649

(a) Contracts represent between 15 percent and 100 percent of net plant output.
(b) Contracts represent between 81 percent and 100 percent of net plant output.

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 19 years. The time periods for fixed payments under natural gas supply contracts are up to three years. The time period for the natural gas supply purchase commitments is up to 15 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, 2017.

(in millions)	Duke Energy	Duke Energy Ohio	Piedmont
2018	$ 314	$ 37	$ 277
2019	280	28	252
2020	252	25	227
2021	249	26	223
2022	226	11	215
Thereafter	1,121	3	1,118
Total	$ 2,442	$ 130	$ 2,312

Operating and Capital Lease Commitments

The Duke Energy Registrants lease office buildings, railcars, vehicles, computer equipment and other property and equipment with various terms and expiration dates. Additionally, Duke Energy Progress has a capital lease 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 on the Consolidated Statements of Operations.

The following tables present rental expense for operating leases. These amounts are included in Operation, maintenance and other on the Consolidated Statements of Operations.

	Years Ended December 31,		
(in millions)	2017	2016	2015
Duke Energy	$ 241	$ 242	$ 313
Duke Energy Carolinas	44	45	41
Progress Energy	130	140	230
Duke Energy Progress	75	68	149
Duke Energy Florida	55	72	81
Duke Energy Ohio	15	16	13
Duke Energy Indiana	23	23	20

	Year Ended	Two Months Ended	Years Ended October 31,	
(in millions)	December 31, 2017	December 31, 2016	2016	2015
Piedmont	$ 7	$ 1	$ 5	$ 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, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
2018	**$ 233**	**$ 36**	**$ 133**	**$ 77**	**$ 56**	**$ 20**	**$ 22**	**$ 6**
2019	**203**	**29**	**126**	**72**	**54**	**12**	**14**	**5**
2020	**183**	**25**	**117**	**62**	**55**	**10**	**10**	**5**
2021	**150**	**19**	**97**	**48**	**49**	**7**	**8**	**6**
2022	**135**	**16**	**90**	**42**	**48**	**4**	**5**	**6**
Thereafter	**882**	**52**	**525**	**344**	**181**	**5**	**7**	**16**
Total	**$ 1,786**	**$ 177**	**$ 1,088**	**$ 645**	**$ 443**	**$ 58**	**$ 66**	**$ 44**

The following table presents future minimum lease payments under capital leases.

	December 31, 2017						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
2018	**$ 168**	**$ 13**	**$ 46**	**$ 21**	**$ 25**	**$ 3**	**$ 2**
2019	**169**	**13**	**45**	**20**	**25**	**1**	**1**
2020	**174**	**13**	**47**	**21**	**26**	**—**	**1**
2021	**176**	**8**	**45**	**22**	**25**	**—**	**1**
2022	**169**	**8**	**45**	**21**	**24**	**—**	**1**
Thereafter	**745**	**109**	**323**	**227**	**95**	**—**	**38**
Minimum annual payments	**1,601**	**164**	**551**	**332**	**220**	**4**	**44**
Less: amount representing interest	**(601)**	**(103)**	**(283)**	**(192)**	**(91)**	**—**	**(33)**
Total	**$ 1,000**	**$ 61**	**$ 268**	**$ 140**	**$ 129**	**$ 4**	**$ 11**

6. DEBT AND CREDIT FACILITIES

Summary of Debt and Related Terms

The following tables summarize outstanding debt.

	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 or letters of credit.

(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 14 days.

(e) Duke Energy includes $1,509 million and $176 million in purchase accounting adjustments related to 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.

	December 31, 2016								
(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 2017-2073	4.30%	$ 17,812	$ 1,150	$ 3,551	$ —	$ 150	$ 810	$ 415	$ 1,835
Secured debt, maturing 2017-2037	2.60%	3,909	425	1,819	300	1,519	—	—	—
First mortgage bonds, maturing 2017-2046[(a)]	4.61%	21,879	7,410	10,800	6,425	4,375	1,000	2,669	—
Capital leases, maturing 2018-2051[(b)]	4.48%	1,100	22	285	142	143	7	11	—
Tax-exempt bonds, maturing 2017-2041[(c)]	2.84%	1,053	355	48	48	—	77	572	—
Notes payable and commercial paper[(d)]	1.01%	3,112	—	—	—	—	—	—	—
Money pool/intercompany borrowings[(e)]		—	300	1,902	150	297	41	150	—
Fair value hedge carrying value adjustment		6	6	—	—	—	—	—	—
Unamortized debt discount and premium, net[(f)]		1,753	(20)	(31)	(16)	(10)	(28)	(9)	(1)
Unamortized debt issuance costs[(g)]		(242)	(45)	(104)	(38)	(52)	(7)	(22)	(13)
Total debt	4.07%	$ 50,382	$ 9,603	$ 18,270	$ 7,011	$ 6,422	$ 1,900	$ 3,786	$ 1,821
Short-term notes payable and commercial paper		(2,487)	—	—	—	—	—	—	—
Short-term money pool/intercompany borrowings		—	—	(729)	—	(297)	(16)	—	—
Current maturities of long-term debt[(h)]		(2,319)	(116)	(778)	(452)	(326)	(1)	(3)	(35)
Total long-term debt[(h)]		$ 45,576	$ 9,487	$ 16,763	$ 6,559	$ 5,799	$ 1,883	$ 3,783	$ 1,786

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.
(b) Duke Energy includes $98 million and $670 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 or letters of credit.
(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 and Piedmont's commercial paper programs were 14 days and eight days, respectively.
(e) Progress Energy amount includes a $1 billion intercompany loan related to the sale of the International Disposal Group. See Note 2 for further discussion of the sale.
(f) Duke Energy includes $1,653 million and $197 million purchase accounting adjustments related to the mergers with Progress Energy and Piedmont, respectively.
(g) Duke Energy includes $53 million in purchase accounting adjustments primarily related to the merger with Progress Energy.
(h) 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, 2017
Unsecured Debt			
Duke Energy (Parent)	June 2018	6.250%	$ 250
Duke Energy (Parent)	June 2018	2.100%	500
Piedmont	December 2018	2.286% (b)	250
First Mortgage Bonds			
Duke Energy Carolinas	January 2018	5.250%	400
Duke Energy Carolinas	April 2018	5.100%	300
Duke Energy Florida	June 2018	5.650%	500
Duke Energy Carolinas	November 2018	7.000%	500
Other(a)			544
Current maturities of long-term debt			$ 3,244

(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, 2017							
(in millions)	Duke Energy(a)	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
2018	$ 3,244	$ 1,205	$ 771	$ 3	$ 768	$ 3	$ 3	$ 250
2019	3,563	6	2,191	903	490	548	61	—
2020	3,699	906	871	304	568	—	502	—
2021	3,760	502	1,472	602	371	48	69	159
2022	3,010	302	1,176	653	74	23	243	—
Thereafter	33,271	7,182	11,356	4,892	4,824	1,445	2,905	1,628
Total long-term debt, including current maturities	$ 50,547	$ 10,103	$ 17,837	$ 7,357	$ 7,095	$ 2,067	$ 3,783	$ 2,037

(a) Excludes $1,732 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, 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**

	December 31, 2016				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy Ohio**	**Duke Energy Indiana**
Tax-exempt bonds	$ 347	$ 35	$ —	$ 27	$ 285
Commercial paper[(a)]	625	300	150	25	150
Total	$ 972	$ 335	$ 150	$ 52	$ 435

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

Summary of Significant Debt Issuances

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

			Year Ended December 31, 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.

			Year Ended December 31, 2016						
Issuance Date	Maturity Date	Interest Rate	Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Unsecured Debt									
April 2016(a)	April 2023	2.875%	$ 350	$ 350	$ —	$ —	$ —	$ —	$ —
August 2016(b)	September 2021	1.800%	750	750	—	—	—	—	—
August 2016(b)	September 2026	2.650%	1,500	1,500	—	—	—	—	—
August 2016(b)	September 2046	3.750%	1,500	1,500	—	—	—	—	—
Secured Debt									
June 2016(c)	March 2020	1.196%	183	—	—	—	183	—	—
June 2016(c)	September 2022	1.731%	150	—	—	—	150	—	—
June 2016(c)	September 2029	2.538%	436	—	—	—	436	—	—
June 2016(c)	March 2033	2.858%	250	—	—	—	250	—	—
June 2016(c)	September 2036	3.112%	275	—	—	—	275	—	—
August 2016(d)	June 2034	2.747% (i)	228	—	—	—	—	—	—
August 2016(d)	June 2020	2.747% (i)	105	—	—	—	—	—	—
First Mortgage Bonds									
March 2016(e)	March 2023	2.500%	500	—	500	—	—	—	—
March 2016(e)	March 2046	3.875%	500	—	500	—	—	—	—
May 2016(f)	May 2046	3.750%	500	—	—	—	—	—	500
June 2016(e)	June 2046	3.700%	250	—	—	—	—	250	—
September 2016(g)	October 2046	3.400%	600	—	—	—	600	—	—
September 2016(e)	October 2046	3.700%	450	—	—	450	—	—	—
November 2016(h)	December 2046	2.950%	600	—	600	—	—	—	—
Total issuances			$ 9,127	$ 4,100	$ 1,600	$ 450	$ 1,894	$ 250	$ 500

(a) Proceeds were used to pay down outstanding commercial paper and for general corporate purposes.

(b) Proceeds were used to finance a portion of the Piedmont acquisition. The $4.9 billion Bridge Facility was terminated following the issuance of this debt. See Note 2 for additional information on the Piedmont acquisition.

(c) DEFPF issued nuclear-asset recovery bonds and used the proceeds to acquire nuclear-asset recovery property from its parent, Duke Energy Florida. The nuclear-asset recovery bonds are payable only from and secured by the nuclear asset-recovery property. DEFPF is consolidated for financial reporting purposes; however, the nuclear asset-recovery bonds do not constitute a debt, liability or other legal obligation of, or interest in, Duke Energy Florida or any of its affiliates other than DEFPF. The assets of DEFPF, including the nuclear-asset recovery property, are not available to pay creditors of Duke Energy Florida or any of its affiliates. Duke Energy Florida used the proceeds from the sale to repay short-term borrowings under the intercompany money pool borrowing arrangement and make an equity distribution of $649 million to the ultimate parent, Duke Energy (Parent), which repaid short-term borrowings. The nuclear-asset recovery bonds are sequential pay amortizing bonds. The maturity date above represents the scheduled final maturity date for the bonds. See Notes 4 and 17 for additional information.

(d) Emerald State Solar, LLC, an indirect wholly owned subsidiary of Duke Energy entered into portfolio financing of approximately 22 North Carolina solar facilities. Tranche A of $228 million is secured by substantially all of the assets of the solar facilities and is nonrecourse to Duke Energy. Tranche B of $105 million is secured by an Equity Contribution Agreement with Duke Energy. Proceeds were used to reimburse Duke Energy for a portion of previously funded construction expenditures related to the Emerald State Solar, LLC portfolio. The initial interest rate on the loans was six months London Interbank Offered Rate (LIBOR) plus an applicable margin of 1.75 percent plus a 0.125 percent increase every three years thereafter. In connection with this debt issuance, Emerald State Solar, LLC entered into two interest rate swaps to convert the substantial majority of the loan interest payments from variable rates to fixed rates of approximately 1.81 percent for Tranche A and 1.38 percent for Tranche B, plus the applicable margin. See Note 14 for further information on the notional amounts of the interest rate swaps.

(e) Proceeds were used to fund capital expenditures for ongoing construction, capital maintenance and for general corporate purposes.

(f) Proceeds were used to repay $325 million of unsecured debt due June 2016, $150 million of first mortgage bonds due July 2016 and for general corporate purposes.

(g) Proceeds were used to fund capital expenditures for ongoing construction, capital maintenance, to repay short-term borrowings under the intercompany money pool borrowing arrangement and for general corporate purposes.

(h) Proceeds were used to repay at maturity $350 million aggregate principal amount of certain bonds due December 2016, as well as to fund capital expenditures for ongoing construction and capital maintenance and for general corporate purposes.

(i) Debt issuance has a floating interest rate.

In July 2016, Piedmont issued $300 million unsecured notes maturing in November 2046 with an interest rate of 3.64%. Piedmont has the option to redeem all or part of the notes before May 1, 2046, at a redemption price equal to the greater of a) 100% of the principal amount of the notes to be redeemed, and b) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed, discounted to the date of redemption on a semi-annual basis at the Treasury Rate as defined in the indenture, as supplemented, plus 25 basis points and any accrued and unpaid interest to the date of redemption. Piedmont has the option to redeem all or part of the notes on or after May 1, 2046, at 100% of the principal amounts plus any accrued and unpaid interest to the date of redemption. Piedmont used the proceeds to fund capital expenditures, to repay short-term borrowings under Piedmont's commercial paper program and for general corporate purposes.

Available Credit Facilities

In March 2017, Duke Energy amended its Master Credit Facility to increase its capacity from $7.5 billion to $8 billion, and to extend the termination date of the facility from January 30, 2020, to March 16, 2022. The amendment also added Piedmont as a borrower within the Master Credit Facility. Piedmont's separate $850 million credit facility was terminated in connection with the amendment. With the amendment, 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.

In January 2018, Duke Energy further amended its Master Credit Facility with consenting lenders to extend $7.65 billion of our existing $8 billion Master Credit Facility by one year to March 16, 2023.

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

	December 31, 2017							
(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	$ 2,850	$ 1,350	$ 1,250	$ 800	$ 450	$ 600	$ 700
Reduction to backstop issuances								
Commercial paper[(b)]	(1,799)	(561)	(371)	(314)	—	(45)	(260)	(248)
Outstanding letters of credit	(63)	(54)	(4)	(2)	(1)	—	—	(2)
Tax-exempt bonds	(81)	—	—	—	—	—	(81)	—
Coal ash set-aside	(500)	—	(250)	(250)	—	—	—	—
Available capacity	$ 5,557	$ 2,235	$ 725	$ 684	$ 799	$ 405	$ 259	$ 450

(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

In June 2017, Duke Energy (Parent) entered into a three-year $1.0 billion revolving credit facility (the Three Year Revolver). Borrowings under this facility will be used for general corporate purposes.

As of December 31, 2017, $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.

Piedmont Term Loan Facility

In June 2017, Piedmont entered into an 18-month term loan facility with commitments totaling $250 million (the Piedmont Term Loan). Borrowings under the facility will be used for general corporate purposes.

As of December 31, 2017, the entire $250 million has been drawn under the Piedmont Term Loan. This balance is classified as 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 Registration statement (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, 2017, and 2016 was $986 million and $1,090 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.

Duke Energy guaranteed debt issued by Duke Energy Carolinas of $650 million and $762 million, respectively, as of December 31, 2017, and 2016.

Money Pool

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

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

Restrictive Debt Covenants

The Duke Energy Registrants' debt and credit agreements contain various financial and other covenants. Duke Energy's Master Credit Facility contains a covenant requiring the debt-to-total capitalization ratio not to exceed 65 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, 2017, 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, 2017, and 2016, Duke Energy had loans outstanding of $701 million, including $38 million at Duke Energy Progress and $661 million, including $39 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 Investments and Other 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, stand-by 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, 2017, 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 Energy Capital, LLC (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, 2017, 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, 2017, was $326 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, $281 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 limited to 47 percent of the outstanding borrowings under the credit facility, which was $312 million as of December 31, 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, 2017, Duke Energy had guaranteed $81 million of outstanding surety bonds, most of which have no set expiration.

Duke Energy uses bank-issued stand-by 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, 2017, Duke Energy had issued a total of $449 million in letters of credit, which expire between 2018 and 2022. The unused amount under these letters of credit was $66 million.

Duke Energy and Progress Energy have issued indemnifications for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses. At December 31, 2017, the estimated maximum exposure for these indemnifications was $89 million, most of which have no set expiration. For certain matters for which Progress Energy receives timely notice, indemnity obligations may extend beyond the notice period. Certain indemnifications related to discontinued operations have no limitations as to time or maximum potential future payments.

Duke Energy recognized $21 million and $13 million, as of December 31, 2017, and 2016, 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, 2017			
(in millions except for ownership interest)	Ownership Interest	Property, Plant and Equipment	Accumulated Depreciation	Construction Work in Progress
Duke Energy Carolinas				
Catawba Nuclear Station (units 1 and 2)[(a)]	19.25%	$ 927	$ 651	$ 19
Lee Combined Combustion Station[(b)]	86.67%	—	—	552
Duke Energy Ohio				
Transmission facilities[(c)]	Various	89	63	1
Duke Energy Indiana				
Gibson Station (unit 5)[(d)]	50.05%	348	162	9
Vermillion Generating Station[(e)]	62.5%	155	120	—
Transmission and local facilities[(d)]	Various	4,672	1,739	—

(a) Jointly owned with North Carolina Municipal Power Agency Number 1, NCEMC and Piedmont Municipal Power Agency.
(b) Jointly owned with NCEMC.
(c) Jointly owned with America Electric Power Generation Resources and The Dayton Power and Light Company.
(d) Jointly owned with Wabash Valley Power Association, Inc. (WVPA) and Indiana Municipal Power Agency.
(e) Jointly owned with WVPA.

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, 2017							
(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)]	**$ 5,371**	**$ 1,944**	**$ 3,246**	**$ 2,564**	**$ 681**	**$ —**	**$ —**	**$ —**
Closure of ash impoundments	**4,525**	**1,629**	**2,094**	**2,075**	**19**	**39**	**763**	**—**
Other[(b)]	**279**	**37**	**74**	**34**	**42**	**45**	**18**	**15**
Total asset retirement obligation	**$ 10,175**	**$ 3,610**	**$ 5,414**	**$ 4,673**	**$ 742**	**$ 84**	**$ 781**	**$ 15**
Less: current portion	**689**	**337**	**295**	**295**	**—**	**3**	**54**	**—**
Total noncurrent asset retirement obligation	**$ 9,486**	**$ 3,273**	**$ 5,119**	**$ 4,378**	**$ 742**	**$ 81**	**$ 727**	**$ 15**

(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 in the table below are stated in 2013 or 2014 dollars, depending on the year of the cost study, and include costs to decommission plant components not subject to radioactive contamination.

(in millions)	**Annual Funding Requirement[(a)]**	**Decommissioning Costs[(a)(b)]**	**Year of Cost Study**
Duke Energy	**$ 14**	**$ 8,150**	2013 and 2014
Duke Energy Carolinas	**—**	**3,420**	2013
Duke Energy Progress	**14**	**3,550**	2014
Duke Energy Florida	**—**	**1,180**	2013

(a) Amounts for Progress Energy equal the sum of Duke Energy Progress and Duke Energy Florida.
(b) Amounts include the Subsidiary Registrant's ownership interest in jointly owned reactors. Other joint owners are responsible for decommissioning costs related to their interest in the reactors.

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 Internal Revenue Service (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. See Note 16 for additional information related to the fair value of the Duke Energy Registrants' NDTFs.

	December 31,	
(in millions)	**2017**	**2016**
Duke Energy	**$ 5,864**	$ 5,099
Duke Energy Carolinas	**3,321**	2,882
Duke Energy Progress	**2,543**	2,217

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

Duke Energy Florida has requested the NRC terminate the operating license for Crystal River Unit 3 as it permanently ceased operation in February 2013. 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 Coal Ash Act, as amended, requires excavation of the Sutton, Riverbend and Dan River basins by August 1, 2019, and Asheville basins by August 1, 2022. Excavation at these sites may include a combination of transfer of coal ash to an engineered landfill or conversion for beneficial use. Basins at the H.F. Lee, Cape Fear and Weatherspoon sites are required to be closed through excavation no later than August 1, 2028. Excavation at these sites can include conversion of the basin to a lined industrial landfill, transfer of ash to an engineered landfill or conversion for beneficial use. The remaining basins are required to be closed no later than December 31, 2024, through conversion to a lined industrial landfill, transfer to an engineered landfill or conversion for beneficial use, unless certain dam improvement projects and alternative drinking water source projects are completed by October 15, 2018. Upon satisfactory completion of these projects, the closure deadline would be extended to December 31, 2029, and could include closure through the combination of a cap system and a groundwater monitoring system.

The Coal Ash Act also required the installation and operation of three large-scale coal ash beneficiation projects to produce reprocessed ash for use in the concrete industry. Duke Energy selected the Buck, H.F. Lee and Cape Fear plants for these projects. Closure at these sites is required to be completed no later than December 31, 2029.

The Coal Ash Act includes a variance procedure for compliance deadlines and other issues surrounding the management of CCR and CCR surface impoundments and prohibits cost recovery in customer rates for unlawful discharge of ash impoundment waters occurring after January 1, 2014. The Coal Ash Act leaves the decision on cost recovery determinations related to closure of ash impoundments to the normal ratemaking processes before utility regulatory commissions. Closure plans and all associated permits must be approved by NCDEQ before any closure work can begin.

The EPA CCR rule establishes requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to ensure the safe disposal and management of CCR. The EPA CCR rule has certain requirements which if not met could initiate impoundment closure and require closure completion within five years. The EPA CCR rule includes extension requirements, which if met could allow the extension of closure completion by up to 10 years.

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 2017 and 2016.

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

During 2017 and 2016, the Duke Energy Registrants updated coal ash ARO liability estimates based on additional site-specific information for the related costs, methods and timing of work to be performed. Actual closure costs incurred could be materially different from current estimates that form the basis of the recorded AROs.

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
Balance at December 31, 2015	$ 10,249	$ 3,918	$ 5,369	$ 4,567	$ 802	$ 125	$ 525
Acquisitions[a]	22	—	2	—	2	—	—
Accretion expense[b]	400	187	230	194	35	5	24
Liabilities settled[c]	(613)	(287)	(272)	(212)	(60)	(5)	(49)
Liabilities incurred in the current year	51	—	3	3	—	—	29
Revisions in estimates of cash flows	502	77	143	145	(1)	(48)	337
Balance at December 31, 2016	10,611	3,895	5,475	4,697	778	77	866
Accretion expense[b]	**435**	**184**	**228**	**195**	**33**	**3**	**32**
Liabilities settled[c]	**(619)**	**(282)**	**(270)**	**(204)**	**(65)**	**(7)**	**(49)**
Liabilities incurred in the current year[d]	**51**	**5**	**—**	**—**	**—**	**7**	**29**
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**

(a) Duke Energy amount relates to the Piedmont acquisition. See Note 2 for additional information.
(b) Substantially all accretion expense for the years ended December 31, 2017, and 2016 relates to Duke Energy's regulated electric operations and has been deferred in accordance with regulatory accounting treatment.
(c) Amounts primarily relate to ash impoundment closures and nuclear decommissioning of Crystal River Unit 3.
(d) Amounts primarily relate to AROs recorded as a result of state agency closure requirements at Duke Energy Indiana.

(in millions)	Piedmont
Balance at October 31, 2015	$ 20
Accretion expense	1
Liabilities settled	(7)
Liabilities incurred in the current year	6
Revisions in estimates of cash flows	(6)
Balance at October 31, 2016	14
Liabilities settled	(1)
Liabilities incurred in the current year	1
Balance at December 31, 2016	14
Accretion expense	**1**
Liabilities settled	**(8)**
Liabilities incurred in the current year	**8**
Balance at December 31, 2017	**$ 15**

10. PROPERTY, PLANT AND EQUIPMENT

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

	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.

	December 31, 2016								
(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		$ 1,501	$ 432	$ 735	$ 393	$ 342	$ 150	$ 106	$ 39
Plant – Regulated									
Electric generation, distribution and transmission	8-100	89,864	34,515	37,596	23,683	13,913	4,593	13,160	—
Natural gas transmission and distribution	12-67	7,738	—	—	—	—	2,456	—	5,282
Other buildings and improvements	15-100	1,692	502	634	293	341	211	197	148
Plant – Nonregulated									
Electric generation, distribution and transmission	5-30	4,298	—	—	—	—	—	—	—
Other buildings and improvements	25-35	421	—	—	—	—	—	—	—
Nuclear fuel		3,572	2,092	1,480	1,480	—	—	—	—
Equipment	3-38	1,941	358	505	378	127	338	156	260
Construction in process		6,186	2,324	2,708	1,329	1,379	206	396	210
Other	5-40	4,184	904	1,206	863	332	172	226	235
Total property, plant and equipment(a)(d)		121,397	41,127	44,864	28,419	16,434	8,126	14,241	6,174
Total accumulated depreciation – regulated(b)(c)(d)		(37,831)	(14,365)	(15,212)	(10,561)	(4,644)	(2,579)	(4,317)	(1,360)
Total accumulated depreciation – nonregulated(c)(d)		(1,575)	—	—	—	—	—	—	—
Generation facilities to be retired, net		529	—	529	529	—	—	—	—
Total net property, plant and equipment		$ 82,520	$ 26,762	$ 30,181	$ 18,387	$ 11,790	$ 5,547	$ 9,924	$ 4,814

(a) Includes capitalized leases of $1,355 million, $40 million, $288 million, $142 million, $146 million, $81 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 $99 million, $9 million and $90 million, respectively, of accumulated amortization of capitalized leases.

(b) Includes $1,922 million, $1,192 million, $730 million and $730 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 $50 million, $9 million, $19 million and $8 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 $2,591 million and accumulated depreciation of consolidated VIEs of $411 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)	**2017**	**2016**	**2015**
Duke Energy	**$ 128**	$ 100	$ 98
Duke Energy Carolinas	**45**	38	38
Progress Energy	**45**	31	24
Duke Energy Progress	**21**	17	20
Duke Energy Florida	**24**	14	4
Duke Energy Ohio	**10**	8	10
Duke Energy Indiana	**9**	7	6

	Year Ended	Two Months Ended	Years Ended October 31,	
(in millions)	**December 31, 2017**	**December 31, 2016**	**2016**	**2015**
Piedmont	**$ 12**	$ 2	$ 12	$ 11

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 $262 million, $216 million, and $172 million for the years ended December 31, 2017, 2016 and 2015. As of December 31, 2017, renewable energy projects owned by Duke Energy and accounted for as operating leases had a cost basis of $3,153 million and accumulated depreciation of $459 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 operating segment for Duke Energy included on Duke Energy's Consolidated Balance Sheets at December 31, 2017, and 2016.

(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total
Goodwill Balance at December 31, 2016	$ 17,379	$ 1,924	$ 122	$ 19,425
Accumulated impairment charges[a]	**—**	**—**	**(29)**	**(29)**
Goodwill at December 31, 2017	**$ 17,379**	**$ 1,924**	**$ 93**	**$ 19,396**

(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.

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, 2017, and 2016.

Progress Energy

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

Piedmont

Piedmont's Goodwill is included in the Gas Utilities and Infrastructure operating segment and there are no accumulated impairment charges. Effective with Piedmont's fiscal year being changed to December 31, as discussed in Note 1, Piedmont changed the date of its annual impairment testing of goodwill from October 31 to August 31 to align with the other Duke Energy Registrants.

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. Except for the Energy Management Solutions reporting unit, 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, 2017 and 2016.

	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	$ —

	December 31, 2016							
(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	$ 6	$ 2	$ 4	$ —	$ 13	$ —
Renewable energy certificates	125	36	84	84	—	4	—	—
Natural gas, coal and power contracts	24	—	—	—	—	—	24	—
Renewable operating and development projects	97	—	—	—	—	—	—	—
Other	6	—	—	—	—	—	—	3
Total gross carrying amounts	271	37	90	86	4	4	37	3
Accumulated amortization – natural gas, coal and power contracts	(17)	—	—	—	—	—	(17)	—
Accumulated amortization – renewable operating and development projects	(23)	—	—	—	—	—	—	—
Accumulated amortization – other	(5)	—	—	—	—	—	—	(3)
Total accumulated amortization	(45)	—	—	—	—	—	(17)	(3)
Total intangible assets, net	$ 226	$ 37	$ 90	$ 86	$ 4	$ 4	$ 20	$ —

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

The following table presents amortization expense for natural gas, coal and power contracts, renewable operating projects and other intangible assets.

	December 31,		
(in millions)	**2017**	**2016**	**2015**
Duke Energy	**$ 7**	$ 6	$ 5
Duke Energy Indiana	**1**	1	1

The table below shows the expected amortization expense for the next five years for intangible assets as of December 31, 2017. The expected amortization expense includes estimates of emission allowances consumption and estimates of consumption of commodities such as natural gas and coal under existing contracts, as well as estimated amortization related to renewable operating projects. The amortization amounts discussed below are estimates and actual amounts may differ from these estimates due to such factors as changes in consumption patterns, sales or impairments of emission allowances or other intangible assets, delays in the in-service dates of renewable assets, additional intangible acquisitions and other events.

(in millions)	**2018**	**2019**	**2020**	**2021**	**2022**
Duke Energy	$ 3	$ 2	$ 2	$ 2	$ 2
Duke Energy Indiana	1	—	—	—	—

12. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

EQUITY METHOD INVESTMENTS

Investments in domestic and international 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,				
	2017		2016		2015
(in millions)	**Investments**	**Equity in earnings**	**Investments**	**Equity in earnings**	**Equity in earnings**
Electric Utilities and Infrastructure	**$ 89**	**$ 5**	$ 93	$ 5	$ (2)
Gas Utilities and Infrastructure	**763**	**62**	566	19	1
Commercial Renewables	**190**	**(5)**	185	(82)	(6)
Other	**133**	**57**	81	43	76
Total	**$ 1,175**	**$ 119**	$ 925	$ (15)	$ 69

During the years ended December 31, 2017, 2016 and 2015, Duke Energy received distributions from equity investments of $13 million, $31 million and $104 million, respectively, which are included in Other assets within Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows. During the year ended December 31, 2017, Duke Energy received distributions from equity investments of $281 million, which are included within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows.

During the year ended December 31, 2017, the two months ended December 31, 2016, and the years ended October 31, 2016, and 2015, Piedmont received distributions from equity investments of $4 million, $1 million, $26 million and $25 million, respectively, which are included in Other assets within Cash Flows from Operating Activities and $2 million, $1 million, $18 million and $2 million, respectively, which are included within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows.

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

Electric Utilities and Infrastructure

Duke Energy owns a 50 percent interest in Duke-American Transmission Co. (DATC) and in Pioneer Transmission, LLC (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, 2017**	**December 31, 2016**
Pipeline Investments			
Atlantic Coast Pipeline, LLC[a]	47%	**$ 397**	$ 265
Sabal Trail Transmission, LLC	7.5%	**219**	140
Constitution Pipeline, LLC[a]	24%	**81**	82
Cardinal Pipeline Company, LLC[b]	21.49%	**11**	16
Storage Facilities			
Pine Needle LNG Company, LLC[b]	45%	**13**	16
Hardy Storage Company, LLC[b]	50%	**42**	47
Total Investments[c]		**$ 763**	**$ 566**

(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.

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 years ended October 31, 2016, and 2015.

For regulatory matters and other information on the ACP, Sabal Trail and Constitution investments, see Notes 4 and 17.

Commercial Renewables

In 2016, Duke Energy sold its interest in three of the Catamount Sweetwater, LLC wind farm projects. Duke Energy has a 47 percent ownership interest in each of the two other Catamount Sweetwater, LLC wind farm projects and 50 percent interest in DS Cornerstone, LLC, which owns wind farm projects in the U.S.

Impairment of Equity Method Investments

Duke Energy evaluated its investment in Constitution for OTTI as of December 31, 2017. Our impairment assessment uses a discounted cash flow income approach, including consideration of the severity and duration of any decline in fair value of our investment in the project. Our key inputs involve significant management judgments and estimates, including projections of the project's cash flows, selection of a discount rate and probability weighting of potential outcomes of legal and regulatory proceedings. Based upon these estimates using information known as of December 31, 2017, the fair value of Duke Energy's investment in Constitution approximated its carrying value. As a result, Duke Energy did not recognize any impairment charge in the year ended December 31, 2017. However, due to the FERC's January 2018 ruling and the resulting increase in uncertainty, Duke Energy is evaluating the potential to recognize a pretax impairment charge on its investment in Constitution during the first quarter of 2018 of up to the current carrying amount of the investment, net of salvage value and any cash and working capital returned. 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 percent 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. The investment in NMC is accounted for under the equity method of accounting.

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)	**2017**	**2016**	**2015**
Duke Energy Carolinas			
Corporate governance and shared service expenses(a)	**$ 858**	$ 831	$ 914
Indemnification coverages(b)	**23**	22	24
JDA revenue(c)	**49**	38	51
JDA expense(c)	**145**	156	183
Intercompany natural gas purchases(d)	**9**	2	—
Progress Energy			
Corporate governance and shared service expenses(a)	**$ 736**	$ 710	$ 712
Indemnification coverages(b)	**38**	35	38
JDA revenue(c)	**145**	156	183
JDA expense(c)	**49**	38	51
Intercompany natural gas purchases(d)	**77**	19	—
Duke Energy Progress			
Corporate governance and shared service expenses(a)	**$ 438**	$ 397	$ 403
Indemnification coverages(b)	**15**	14	16
JDA revenue(c)	**145**	156	183
JDA expense(c)	**49**	38	51
Intercompany natural gas purchases(d)	**77**	19	—
Duke Energy Florida			
Corporate governance and shared service expenses(a)	**$ 298**	$ 313	$ 309
Indemnification coverages(b)	**23**	21	22
Duke Energy Ohio			
Corporate governance and shared service expenses(a)	**$ 363**	$ 356	$ 342
Indemnification coverages(b)	**5**	5	6
Duke Energy Indiana			
Corporate governance and shared service expenses(a)	**$ 370**	$ 366	$ 349
Indemnification coverages(b)	**8**	8	9
Piedmont			
Corporate governance and shared service expenses(a)	**$ 50**		
Indemnification coverages(b)	**2**		
Intercompany natural gas sales(d)	**86**		

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

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

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

(d) Piedmont provides long-term natural gas delivery service to certain Duke Energy Carolinas and Duke Energy Progress natural gas-fired generation facilities. Piedmont records the sales in Regulated natural gas revenues, and Duke Energy Carolinas and Duke Energy Progress record the related purchases in Fuel used in electric generation and purchased power on their respective Consolidated Statements of Operations and Comprehensive Income. The amounts are not eliminated in accordance with rate-based accounting regulations. 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, and for the year ended October 31, 2015, Piedmont recorded $74 million and $83 million, respectively of natural gas sales with Duke Energy.

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 were not material for the years ended December 31, 2017, 2016 and 2015.

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.

Refer to Note 2 for further information on the sale of the Midwest Generation Disposal Group.

Equity Method Investments

Piedmont has related party transactions as a customer of its equity method investments in natural gas storage and transportation facilities. The following table presents expenses that are included in Cost of natural gas on Piedmont's Consolidated Statements of Operations and Comprehensive Income.

		Year Ended December 31,	**Two Months Ended December 31,**	**Years Ended October 31,**	
(in millions)	**Type of expense**	**2017**	**2016**	**2016**	**2015**
Cardinal	Transportation Costs	**$ 8**	$ 2	$ 9	$ 9
Pine Needle	Natural Gas Storage Costs	**8**	2	11	11
Hardy Storage	Natural Gas Storage Costs	**9**	2	9	9
Total		**$ 25**	$ 6	$ 29	$ 29

Piedmont had accounts payable to its equity method investments of $2 million at December 31, 2017, and 2016 related to these transactions. These amounts are included in Accounts payable on the Consolidated Balance Sheets.

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, 2017							
Intercompany income tax receivable	**$ —**	**$ 168**	**$ —**	**$ 44**	**$ 22**	**$ —**	**$ 7**
Intercompany income tax payable	**44**	**—**	**21**	**—**	**—**	**35**	**—**
December 31, 2016							
Intercompany income tax receivable	$ 1	$ —	$ —	$ 37	$ —	$ —	$ —
Intercompany income tax payable	—	37	90	—	1	3	38

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 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. See the Consolidated Statements of Changes in Equity for gains and losses reclassified out of AOCI for the years ended December 31, 2017, and 2016. 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 include contracts not designated as a hedge because they are accounted for under regulatory accounting and 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.

In August 2016, Duke Energy unwound $1.4 billion of forward-starting interest rate swaps associated with the Piedmont acquisition financing described in Note 6. 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, 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**

	December 31, 2016					
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**
Cash flow hedges[a]	$ 750	$ —	$ —	$ —	$ —	$ —
Undesignated contracts	927	400	500	250	250	27
Total notional amount	$ 1,677	$ 400	$ 500	$ 250	$ 250	$ 27

(a) Duke Energy includes amounts related to consolidated VIEs of $660 million and $750 million at December 31, 2017, and 2016, respectively. During 2016, Duke Energy entered into interest rate swaps related to solar financing with an outstanding notional amount of $300 million, including $81 million of four-year swaps and $219 million of 18-year swaps, at December 31, 2016. See note 6 for additional information related to the solar facilities financing.

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, 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**

	December 31, 2016						
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana	Piedmont
Electricity (gigawatt-hours)	147	—	—	—	—	147	—
Natural gas (millions of dekatherms)	890	91	269	118	151	1	529

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, 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

Derivative Assets	December 31, 2016							
(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	$ 108	$ 23	$ 61	$ 35	$ 26	$ 4	$ 16	$ 3
Noncurrent	32	10	21	10	11	1	—	—
Total Derivative Assets – Commodity Contracts	$ 140	$ 33	$ 82	$ 45	$ 37	$ 5	$ 16	$ 3
Interest Rate Contracts								
Designated as Hedging Instruments								
Noncurrent	$ 19	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Not Designated as Hedging Instruments								
Current	3	—	3	1	2	—	—	—
Total Derivative Assets – Interest Rate Contracts	$ 22	$ —	$ 3	$ 1	$ 2	$ —	$ —	$ —
Total Derivative Assets	$ 162	$ 33	$ 85	$ 46	$ 39	$ 5	$ 16	$ 3

Derivative Liabilities	December 31, 2016							
(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	$ 43	$ —	$ 12	$ —	$ 12	$ —	$ 2	$ 35
Noncurrent	166	1	7	1	—	—	—	152
Total Derivative Liabilities – Commodity Contracts	$ 209	$ 1	$ 19	$ 1	$ 12	$ —	$ 2	$ 187
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 8	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	8	—	—	—	—	—	—	—
Not Designated as Hedging Instruments								
Current	1	—	—	—	—	1	—	—
Noncurrent	26	15	6	6	—	5	—	—
Total Derivative Liabilities – Interest Rate Contracts	$ 43	$ 15	$ 6	$ 6	$ —	$ 6	$ —	$ —
Total Derivative Liabilities	$ 252	$ 16	$ 25	$ 7	$ 12	$ 6	$ 2	$ 187

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, 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

Derivative Assets	December 31, 2016							
(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	$ 111	$ 23	$ 64	$ 36	$ 28	$ 4	$ 16	$ 3
Gross amounts offset	(11)	—	(11)	—	(11)	—	—	—
Net amounts presented in Current Assets: Other	$ 100	$ 23	$ 53	$ 36	$ 17	$ 4	$ 16	$ 3
Noncurrent								
Gross amounts recognized	$ 51	$ 10	$ 21	$ 10	$ 11	$ 1	$ —	$ —
Gross amounts offset	(2)	(1)	(1)	(1)	—	—	—	—
Net amounts presented in Other Noncurrent Assets: Other	$ 49	$ 9	$ 20	$ 9	$ 11	$ 1	$ —	$ —

Derivative Liabilities	December 31, 2016							
(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	$ 52	$ —	$ 12	$ —	$ 12	$ 1	$ 2	$ 35
Gross amounts offset	(11)	—	(11)	—	(11)	—	—	—
Net amounts presented in Current Liabilities: Other	$ 41	$ —	$ 1	$ —	$ 1	$ 1	$ 2	$ 35
Noncurrent								
Gross amounts recognized	$ 200	$ 16	$ 13	$ 7	$ —	$ 5	$ —	$ 152
Gross amounts offset	(2)	(1)	(1)	(1)	—	—	—	—
Net amounts presented in Other Noncurrent Liabilities: Other	$ 198	$ 15	$ 12	$ 6	$ —	$ 5	$ —	$ 152

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, 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**

	December 31, 2016				
(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	$ 34	$ 16	$ 18	$ 6	$ 12
Fair value of collateral already posted	—	—	—	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	34	16	18	6	12

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

The Duke Energy Registrants classify their investments in debt and equity securities as either trading or available-for-sale.

TRADING SECURITIES

Piedmont's investments in debt and equity securities held in rabbi trusts associated with certain deferred compensation plans are classified as trading securities. The fair value of these investments was $1 million and $5 million as of December 31, 2017, and 2016, respectively.

AVAILABLE-FOR-SALE (AFS) SECURITIES

All other investments in debt and equity securities are classified as AFS.

Duke Energy’s AFS securities are primarily comprised of investments held in (i) the nuclear decommissioning trust funds (NDTF) at Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, (ii) grantor trusts at Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana related to OPEB plans and (iii) Bison.

Duke Energy classifies all other investments in debt and equity securities as long term, unless otherwise noted.

Investment Trusts

The investments within the NDTF investments and the Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana grantor trusts (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 and equity securities within the Investment Trusts are considered OTTIs and are recognized immediately.

Investments within the Investment Trusts generally qualify for regulatory accounting and accordingly realized and unrealized gains and losses are generally deferred as a regulatory asset or liability.

Substantially all amounts of the Duke Energy Registrants' gross unrealized holding losses as of December 31, 2017, and 2016, are considered OTTIs on investments within Investment Trusts that have been recognized immediately as a regulatory asset.

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. If an OTTI exists, the unrealized loss is included in earnings based on the criteria discussed below.

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. Criteria used to evaluate whether an impairment associated with equity securities is other-than-temporary includes, but is not limited to, (i) the length of time over which the market value has been lower than the cost basis of the investment, (ii) the percentage decline compared to the cost of the investment and (iii) management’s intent and ability to retain its investment for a period of time sufficient to allow for any anticipated recovery in market value. If a decline in fair value is determined to be other-than-temporary, the investment is written down to its fair value through a charge to earnings.

If the entity does not have an intent to sell a debt security and it is not more likely than not management will be required to sell the debt security before the recovery of its cost basis, the impairment write-down to fair value would be recorded as a component of other comprehensive income, except for when it is determined a credit loss exists. In determining whether a credit loss exists, management considers, among other things, (i) the length of time and the extent to which the fair value has been less than the amortized cost basis, (ii) changes in the financial condition of the issuer of the security, or in the case of an asset backed security, the financial condition of the underlying loan obligors, (iii) consideration of underlying collateral and guarantees of amounts by government entities, (iv) ability of the issuer of the security to make scheduled interest or principal payments and (v) any changes to the rating of the security by rating agencies. If a credit loss exists, the amount of impairment write-down to fair value is split between credit loss and other factors. The amount related to credit loss is recognized in earnings. The amount related to other factors is recognized in other comprehensive income. There were no material credit losses as of December 31, 2017, and 2016.

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 AFS securities.

	December 31, 2017			December 31, 2016		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 115**	$ —	$ —	$ 111
Equity securities	**2,805**	**27**	**4,914**	2,092	54	4,106
Corporate debt securities	**17**	**2**	**570**	10	8	528
Municipal bonds	**4**	**3**	**344**	3	10	331
U.S. government bonds	**11**	**7**	**1,027**	10	8	984
Other debt securities	**—**	**1**	**118**	—	3	124
Total NDTF	**$ 2,837**	**$ 40**	**$ 7,088**	$ 2,115	$ 83	$ 6,184
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 15**	$ —	$ —	$ 25
Equity securities	**59**	**—**	**123**	38	—	104
Corporate debt securities	**1**	**—**	**57**	1	1	66
Municipal bonds	**2**	**1**	**83**	2	1	82
U.S. government bonds	**—**	**—**	**41**	—	1	51
Other debt securities	**—**	**1**	**44**	—	2	42
Total Other Investments	**$ 62**	**$ 2**	**$ 363**	$ 41	$ 5	$ 370
Total Investments	**$ 2,899**	**$ 42**	**$ 7,451**	$ 2,156	$ 88	$ 6,554

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2017**
Due in one year or less	**$ 117**
Due after one through five years	**552**
Due after five through 10 years	**554**
Due after 10 years	**1,061**
Total	**$ 2,284**

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were as follows.

	Years Ended December 31,		
(in millions)	**2017**	2016	2015
Realized gains	**$ 202**	$ 246	$ 193
Realized losses	**160**	187	98

DUKE ENERGY CAROLINAS

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017			December 31, 2016		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses(a)	Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 32	$ —	$ —	$ 18
Equity securities	1,531	12	2,692	1,157	28	2,245
Corporate debt securities	9	2	359	5	6	354
Municipal bonds	—	1	60	1	2	67
U.S. government bonds	3	4	503	2	5	458
Other debt securities	—	1	112	—	3	116
Total NDTF	$ 1,543	$ 20	$ 3,758	$ 1,165	$ 44	$ 3,258
Other Investments						
Other debt securities	$ —	$ —	$ —	$ —	$ 1	$ 3
Total Other Investments	$ —	$ —	$ —	$ —	$ 1	$ 3
Total Investments	$ 1,543	$ 20	$ 3,758	$ 1,165	$ 45	$ 3,261

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2017
Due in one year or less	$ 9
Due after one through five years	204
Due after five through 10 years	300
Due after 10 years	521
Total	$ 1,034

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were as follows.

	Years Ended December 31,		
(in millions)	2017	2016	2015
Realized gains	$ 135	$ 157	$ 158
Realized losses	103	121	83

PROGRESS ENERGY

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017			December 31, 2016		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses(a)	Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 83	$ —	$ —	$ 93
Equity securities	1,274	15	2,222	935	26	1,861
Corporate debt securities	8	—	211	5	2	174
Municipal bonds	4	2	284	2	8	264
U.S. government bonds	8	3	524	8	3	526
Other debt securities	—	—	6	—	—	8
Total NDTF	$ 1,294	$ 20	$ 3,330	$ 950	$ 39	$ 2,926
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 12	$ —	$ —	$ 21
Municipal bonds	2	—	47	2	—	44
Total Other Investments	$ 2	$ —	$ 59	$ 2	$ —	$ 65
Total Investments	$ 1,296	$ 20	$ 3,389	$ 952	$ 39	$ 2,991

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2017
Due in one year or less	$ 94
Due after one through five years	301
Due after five through 10 years	203
Due after 10 years	474
Total	$ 1,072

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were as follows.

	Years Ended December 31,		
(in millions)	2017	2016	2015
Realized gains	$ 65	$ 84	$ 33
Realized losses	56	64	13

DUKE ENERGY PROGRESS

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017			December 31, 2016		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses(a)	Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 50	$ —	$ —	$ 45
Equity securities	980	12	1,795	704	21	1,505
Corporate debt securities	6	—	149	4	1	120
Municipal bonds	4	2	283	2	8	263
U.S. government bonds	5	2	310	5	2	275
Other debt securities	—	—	4	—	—	5
Total NDTF	$ 995	$ 16	$ 2,591	$ 715	$ 32	$ 2,213
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 1	$ —	$ —	$ 1
Total Other Investments	$ —	$ —	$ 1	$ —	$ —	$ 1
Total Investments	$ 995	$ 16	$ 2,592	$ 715	$ 32	$ 2,214

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2017
Due in one year or less	$ 21
Due after one through five years	219
Due after five through 10 years	146
Due after 10 years	360
Total	$ 746

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were as follows.

	Years Ended December 31,		
(in millions)	2017	2016	2015
Realized gains	$ 54	$ 71	$ 26
Realized losses	48	55	11

DUKE ENERGY FLORIDA

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017						December 31, 2016					
(in millions)		Gross Unrealized Holding Gains		Gross Unrealized Holding Losses		Estimated Fair Value		Gross Unrealized Holding Gains		Gross Unrealized Holding Losses(a)		Estimated Fair Value
NDTF												
Cash and cash equivalents	**$**	**—**	**$**	**—**	**$**	**33**	$	—	$	—	$	48
Equity securities		**294**		**3**		**427**		231		5		356
Corporate debt securities		**2**		**—**		**62**		1		1		54
Municipal bonds		**—**		**—**		**1**		—		—		1
U.S. government bonds		**3**		**1**		**214**		3		1		251
Other debt securities		**—**		**—**		**2**		—		—		3
Total NDTF(a)	**$**	**299**	**$**	**4**	**$**	**739**	$	235	$	7	$	713
Other Investments												
Cash and cash equivalents	**$**	**—**	**$**	**—**	**$**	**1**	$	—	$	—	$	4
Municipal bonds		**2**		**—**		**47**		2		—		44
Total Other Investments	**$**	**2**	**$**	**—**	**$**	**48**	$	2	$	—	$	48
Total Investments	**$**	**301**	**$**	**4**	**$**	**787**	$	237	$	7	$	761

(a) During the year ended December 31, 2017, 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, 2017
Due in one year or less	**$**	**73**
Due after one through five years		**82**
Due after five through 10 years		**57**
Due after 10 years		**114**
Total	**$**	**326**

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were as follows.

	Years Ended December 31,					
(in millions)		**2017**		2016		2015
Realized gains	**$**	**11**	$	13	$	7
Realized losses		**8**		9		2

DUKE ENERGY INDIANA

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017			December 31, 2016		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
Other Investments						
Equity securities	$ **49**	$ **—**	$ **97**	$ 33	$ —	$ 79
Corporate debt securities	**—**	**—**	**3**	—	—	2
Municipal bonds	**—**	**1**	**28**	—	1	28
U.S. government bonds	**—**	**—**	**—**	—	—	1
Total Other Investments	$ **49**	$ **1**	$ **128**	$ 33	$ 1	$ 110
Total Investments	$ **49**	$ **1**	$ **128**	$ 33	$ 1	$ 110

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2017**
Due in one year or less	$ **5**
Due after one through five years	**12**
Due after five through 10 years	**7**
Due after 10 years	**7**
Total	$ **31**

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were insignificant for the years ended December 31, 2017, 2016 and 2015.

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:

Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities that the reporting entity can access at the measurement date. An active market is one in which transactions for an asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 – A fair value measurement utilizing inputs other than quoted prices included in Level 1 that are observable, either directly or indirectly, for an asset or liability. Inputs include (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in markets that are not active, and (iii) inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities and credit spreads. A Level 2 measurement cannot have more than an insignificant portion of its valuation based on unobservable inputs. Instruments in this category include non-exchange-traded derivatives, such as over-the-counter forwards, swaps and options; certain marketable debt securities; and financial instruments traded in less than active markets.

Level 3 – Any fair value measurement which includes unobservable inputs for more than an insignificant portion of the valuation. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 measurements may include longer-term instruments that extend into periods in which observable inputs are not available.

Not Categorized – Certain investments are not categorized within the Fair Value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

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, 2017, 2016 and 2015. In addition, for Piedmont, there were no transfers between levels during the two months ended December 31, 2016, and the years ended October 31, 2016, and 2015.

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 New York Stock Exchange (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 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. See Note 2 related to the acquisition of Piedmont in 2016 and the purchase of NCEMPA's ownership interests in certain generating assets in 2015.

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 table 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, 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 AFS equity securities	**123**	**123**	**—**	**—**	**—**
Other trading and AFS 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**

	December 31, 2016				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
NDTF equity securities	$ 4,106	$ 4,029	$ —	$ —	$ 77
NDTF debt securities	2,078	632	1,446	—	—
Other trading and AFS equity securities	104	104	—	—	—
Other trading and AFS debt securities	266	75	186	5	—
Derivative assets	162	5	136	21	—
Total assets	6,716	4,845	1,768	26	77
Derivative liabilities	(252)	(2)	(63)	(187)	—
Net assets	$ 6,464	$ 4,843	$ 1,705	$ (161)	$ 77

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, 2017			December 31, 2016		
(in millions)	**Investments**	**Derivatives (net)**	**Total**	**Investments**	**Derivatives (net)**	**Total**
Balance at beginning of period	**$ 5**	**$ (166)**	**$ (161)**	$ 5	$ 10	$ 15
Total pretax realized or unrealized gains included in comprehensive income	**1**	**—**	**1**	—	—	—
Derivative liability resulting from the acquisition of Piedmont	**—**	**—**	**—**	—	(187)	(187)
Purchases, sales, issuances and settlements:						
Purchases	**—**	**55**	**55**	—	33	33
Sales	**(6)**	**—**	**(6)**	—	—	—
Settlements	**—**	**(47)**	**(47)**	—	(28)	(28)
Total gains included on the Consolidated Balance Sheet	**—**	**44**	**44**	—	6	6
Balance at end of period	**$ —**	**$ (114)**	**$ (114)**	$ 5	$ (166)	$ (161)

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, 2017				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**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**

	December 31, 2016				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
NDTF equity securities	$ 2,245	$ 2,168	$ —	$ —	$ 77
NDTF debt securities	1,013	178	835	—	—
Other AFS debt securities	3	—	—	3	—
Derivative assets	33	—	33	—	—
Total assets	3,294	2,346	868	3	77
Derivative liabilities	(16)	—	(16)	—	—
Net assets	$ 3,278	$ 2,346	$ 852	$ 3	$ 77

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

	Investments	
	Years Ended December 31,	
(in millions)	**2017**	**2016**
Balance at beginning of period	$ 3	$ 3
Total pretax realized or unrealized gains included in comprehensive income	1	—
Purchases, sales, issuances and settlements:		
Sales	(4)	—
Balance at end of period	$ —	$ 3

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, 2017			December 31, 2016		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Total Fair Value**	**Level 1**	**Level 2**
NDTF equity securities	$ 2,222	$ 2,222	$ —	$ 1,861	$ 1,861	$ —
NDTF debt securities	1,108	431	677	1,065	454	611
Other AFS debt securities	59	12	47	65	21	44
Derivative assets	3	1	2	85	—	85
Total assets	3,392	2,666	726	3,076	2,336	740
Derivative liabilities	(36)	(1)	(35)	(25)	—	(25)
Net assets	$ 3,356	$ 2,665	$ 691	$ 3,051	$ 2,336	$ 715

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, 2017			December 31, 2016		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Total Fair Value**	**Level 1**	**Level 2**
NDTF equity securities	$ 1,795	$ 1,795	$ —	$ 1,505	$ 1,505	$ —
NDTF debt securities	796	243	553	708	207	501
Other AFS debt securities	1	1	—	1	1	—
Derivative assets	2	1	1	46	—	46
Total assets	2,594	2,040	554	2,260	1,713	547
Derivative liabilities	(18)	(1)	(17)	(7)	—	(7)
Net assets	$ 2,576	$ 2,039	$ 537	$ 2,253	$ 1,713	$ 540

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, 2017			December 31, 2016		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Total Fair Value**	**Level 1**	**Level 2**
NDTF equity securities	**$ 427**	**$ 427**	**$ —**	$ 356	$ 356	$ —
NDTF debt securities	**312**	**188**	**124**	357	247	110
Other AFS debt securities	**48**	**1**	**47**	48	4	44
Derivative assets	**1**	**—**	**1**	39	—	39
Total assets	**788**	**616**	**172**	800	607	193
Derivative liabilities	**(12)**	**—**	**(12)**	(12)	—	(12)
Net assets	**$ 776**	**$ 616**	**$ 160**	$ 788	$ 607	$ 181

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, 2017			December 31, 2016		
(in millions)	**Total Fair Value**	**Level 2**	**Level 3**	**Total Fair Value**	**Level 2**	**Level 3**
Derivative assets	**$ 1**	**$ —**	**$ 1**	$ 5	$ —	$ 5
Derivative liabilities	**(5)**	**(5)**	**—**	(6)	(6)	—
Net (liabilities) assets	**$ (4)**	**$ (5)**	**$ 1**	$ (1)	$ (6)	$ 5

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)	**2017**	**2016**
Balance at beginning of period	**$ 5**	$ 3
Purchases, sales, issuances and settlements:		
Purchases	**3**	5
Settlements	**(4)**	(5)
Total gains included on the Consolidated Balance Sheet	**(3)**	2
Balance at end of period	**$ 1**	$ 5

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, 2017				December 31, 2016			
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Total Fair Value	Level 1	Level 2	Level 3
Other AFS equity securities	$ 97	$ 97	$ —	$ —	$ 79	$ 79	$ —	$ —
Other AFS debt securities	31	—	31	—	31	—	31	—
Derivative assets	27	—	—	27	16	—	—	16
Total assets	155	97	31	27	126	79	31	16
Derivative liabilities	—	—	—	—	(2)	(2)	—	—
Net assets	$ 155	$ 97	$ 31	$ 27	$ 124	$ 77	$ 31	$ 16

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)	2017	2016
Balance at beginning of period	$ 16	$ 7
Purchases, sales, issuances and settlements:		
Purchases	52	29
Settlements	(43)	(24)
Total gains included on the Consolidated Balance Sheet	2	4
Balance at end of period	$ 27	$ 16

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, 2017			December 31, 2016		
(in millions)	Total Fair Value	Level 1	Level 3	Total Fair Value	Level 1	Level 3
Other trading equity securities	$ —	$ —	$ —	$ 4	$ 4	$ —
Other trading debt securities	1	1	—	1	1	—
Derivative assets	2	2	—	3	3	—
Total assets	3	3	—	8	8	—
Derivative liabilities	(142)	—	(142)	(187)	—	(187)
Net assets	$ (139)	$ 3	$ (142)	$ (179)	$ 8	$ (187)

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)		
	Year Ended	Two Months Ended	Year Ended
(in millions)	December 31, 2017	December 31, 2016	October 31, 2016
Balance at beginning of period	**$ (187)**	$ (188)	$ —
Total gains (losses) and settlements	**45**	1	(188)
Balance at end of period	**$ (142)**	$ (187)	$ (188)

QUANTITATIVE INFORMATION ABOUT UNOBSERVABLE INPUTS

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

	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)**			

	December 31, 2016			
Investment Type	Fair Value (in millions)	Valuation Technique	Unobservable Input	Range
Duke Energy Ohio				
FTRs	$ 5	RTO auction pricing	FTR price – per MWh	0.77 – 3.52
Duke Energy Indiana				
FTRs	16	RTO auction pricing	FTR price – per MWh	(0.83) – 9.32
Piedmont				
Natural gas contracts	(187)	Discounted cash flow	Forward natural gas curves - price per MMBtu	2.31 – 4.18
Duke Energy				
Total Level 3 derivatives	$ (166)			

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, 2017		December 31, 2016	
(in millions)	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
Duke Energy	**$ 52,279**	**$ 55,331**	$ 47,895	$ 49,161
Duke Energy Carolinas	**10,103**	**11,372**	9,603	10,494
Progress Energy	**17,837**	**20,000**	17,541	19,107
Duke Energy Progress	**7,357**	**7,992**	7,011	7,357
Duke Energy Florida	**7,095**	**7,953**	6,125	6,728
Duke Energy Ohio	**2,067**	**2,249**	1,884	2,020
Duke Energy Indiana	**3,783**	**4,464**	3,786	4,260
Piedmont	**2,037**	**2,209**	1,821	1,933

At both December 31, 2017, and December 31, 2016, 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, 2017, 2016 and 2015, or is expected to be provided in the future, that was not previously contractually required.

Receivables Financing – DERF/DEPR/DEFR

Duke Energy Receivables Finance Company, LLC (DERF), Duke Energy Progress Receivables, LLC (DEPR) and Duke Energy Florida Receivables, LLC (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 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 typically 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 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 2019	April 2019
Credit facility amount (in millions)	$ 325	$ 450	$ 300	$ 225
Amounts borrowed at December 31, 2017	325	450	300	225
Amounts borrowed at December 31, 2016	325	425	300	225

Nuclear Asset-Recovery Bonds – DEFPF

Duke Energy Florida Project Finance, LLC (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 June 2016, DEFPF issued $1,294 million of 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, 2017	December 31, 2016
Receivables of VIEs	**$ 4**	$ 6
Regulatory Assets: Current	**51**	50
Current Assets: Other	**40**	53
Other Noncurrent Assets: Regulatory assets	**1,091**	1,142
Current Liabilities: Other	**10**	17
Current maturities of long-term debt	**53**	62
Long-Term Debt	**1,164**	1,217

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. The activities that most significantly impact the economic performance of these renewable energy facilities were decisions associated with siting, negotiating PPAs, engineering, procurement and construction and decisions associated with ongoing operations and maintenance-related activities. Duke Energy 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, 2017	December 31, 2016
Current Assets: Other	**$ 174**	$ 223
Property, plant and equipment, cost	**3,923**	3,419
Accumulated depreciation and amortization	**(591)**	(453)
Current maturities of long-term debt	**170**	198
Long-Term Debt	**1,700**	1,097
Other Noncurrent Liabilities: Deferred income taxes	**(148)**	275
Other Noncurrent Liabilities: Other	**241**	252

NON-CONSOLIDATED VIEs

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

	December 31, 2017					
	Duke Energy				Duke	Duke
(in millions)	**Pipeline Investments**	**Commercial Renewables**	**Other VIEs(a)**	**Total**	**Energy Ohio**	**Energy 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

(a) Duke Energy holds a 50 percent equity interest in Duke-American Transmission Company, LLC (DATC). As of December 31, 2016, DATC was considered a VIE due to having insufficient equity to finance its own activities without subordinated financial support. However, DATC is no longer considered a VIE based on sufficient equity to finance its own activities, and, therefore, is no longer considered a VIE as of December 31, 2017. Duke Energy's investment in DATC was $46 million at December 31, 2017.

	December 31, 2016						
	Duke Energy				Duke	Duke	
(in millions)	**Pipeline Investments**	**Commercial Renewables**	**Other**	**Total**	**Energy Ohio**	**Energy Indiana**	**Piedmont (a)**
Receivables from affiliated companies	$ —	$ —	$ —	$ —	$ 82	$ 101	$ —
Investments in equity method unconsolidated affiliates	487	174	90	751	—	—	139
Other noncurrent assets	12	—	—	12	—	—	—
Total assets	$ 499	$ 174	$ 90	$ 763	$ 82	$ 101	$ 139
Other current liabilities	—	—	3	3	—	—	—
Other noncurrent liabilities	—	—	13	13	—	—	4
Total liabilities	$ —	$ —	$ 16	$ 16	$ —	$ —	$ 4
Net assets	$ 499	$ 174	$ 74	$ 747	$ 82	$ 101	$ 135

(a) In April 2017, Piedmont transferred its non-consolidated VIE investments to a wholly owned subsidiary of Duke Energy. See Note 12 and the "Pipeline Investments" section below for additional detail.

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, some of which are reflected in the table above as Other noncurrent liabilities. 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 in these joint ventures.

		Investment Amount (in millions)	
Entity Name	Ownership Interest	December 31, 2017	December 31, 2016
ACP	47%	$ **397**	$ 265
Sabal Trail	7.5%	**219**	140
Constitution	24%	**81**	82
Total		$ **697**	$ 487

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.

Other VIEs

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 their activities without subordinated financial support. As a counterparty to an inter-company power agreement (ICPA), Duke Energy Ohio has a contractual arrangement to buy power 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, including costs associated with its 2,256 MW of coal-fired generation capacity. Deterioration in the credit quality, or bankruptcy of one or more parties to the ICPA could increase the costs of OVEC. In addition, certain proposed environmental rulemaking could result in future increased cost allocations.

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	
	2017	**2016**	**2017**	**2016**
Anticipated credit loss ratio	**0.5%**	0.5%	**0.3%**	0.3%
Discount rate	**2.1%**	1.5%	**2.1%**	1.5%
Receivable turnover rate	**13.5%**	13.3%	**10.7%**	10.6%

The following table shows the gross and net receivables sold.

	Duke Energy Ohio		Duke Energy Indiana	
(in millions)	**2017**	**2016**	**2017**	**2016**
Receivables sold	**$ 273**	$ 267	**$ 312**	$ 306
Less: Retained interests	**87**	82	**106**	101
Net receivables sold	**$ 186**	$ 185	**$ 206**	$ 205

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)	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Sales						
Receivables sold	**$ 1,879**	$ 1,926	$ 1,963	**$ 2,711**	$ 2,635	$ 2,627
Loss recognized on sale	**10**	9	9	**12**	11	11
Cash Flows						
Cash proceeds from receivables sold	**1,865**	1,882	1,995	**2,694**	2,583	2,670
Collection fees received	**1**	1	1	**1**	1	1
Return received on retained interests	**3**	2	3	**7**	5	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. COMMON STOCK

Basic Earnings Per Share (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)	**2017**	**2016**	**2015**
Income from continuing operations attributable to Duke Energy common stockholders excluding impact of participating securities	**$ 3,059**	$ 2,567	$ 2,640
Weighted average shares outstanding – basic	**700**	691	694
Weighted average shares outstanding – diluted	**700**	691	694
Earnings per share from continuing operations attributable to Duke Energy common stockholders			
Basic	**$ 4.37**	$ 3.71	$ 3.80
Diluted	**$ 4.37**	$ 3.71	$ 3.80
Potentially dilutive items excluded from the calculation(a)	**2**	2	2
Dividends declared per common share	**$ 3.49**	$ 3.36	$ 3.24

(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 Distribution Agreement

On February 20, 2018, Duke Energy filed a prospectus supplement and executed an Equity Distribution Agreement (the EDA) under which it may sell up to $1 billion of its common stock through an at-the-market 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 either of the Agents, shares of common stock during the period ending September 23, 2019.

In addition to the issuance and sales of shares by Duke Energy through the Agents, Duke Energy may enter into Equity Forward Agreements with affiliates of the Agents as Forward Purchasers. There were no transactions under the EDA from the time of execution of the EDA to the filing of this document.

Stock Issuance

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.

Accelerated Stock Repurchase Program

On April 6, 2015, Duke Energy entered into agreements with each of Goldman, Sachs & Co. and JPMorgan Chase Bank, National Association (the Dealers) to repurchase a total of $1.5 billion of Duke Energy common stock under an accelerated stock repurchase program (the ASR). Duke Energy made payments of $750 million to each of the Dealers and was delivered 16.6 million shares, with a total fair value of $1.275 billion, which represented approximately 85 percent of the total number of shares of Duke Energy common stock expected to be repurchased under the ASR. The company recorded the $1.5 billion payment as a reduction to common stock as of April 6, 2015. In June 2015, the Dealers delivered 3.2 million additional shares to Duke Energy to complete the ASR. Approximately 19.8 million shares, in total, were delivered to Duke Energy and retired under the ASR at an average price of $75.75 per share. The final number of shares repurchased was based upon the average of the daily volume weighted average stock prices of Duke Energy's common stock during the term of the program, less a discount.

19. SEVERANCE

As part of its strategic planning processes, Duke Energy implemented targeted cost savings initiatives during 2016 and 2015 aimed at reducing operations and maintenance expense. The initiatives included efforts to reduce costs through the standardization of processes and systems, leveraging technology and workforce optimization throughout the company.

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 continue to be implemented and are 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 costs for initiatives and plans discussed above were accrued for a total of approximately 100 employees in 2017, 600 employees in 2016 and 900 employees in 2015. The following table presents the direct and allocated severance and related expenses 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, 2017	**$ 15**	**$ 2**	**$ 2**	**$ 1**	**$ 1**	**$ —**	**$ 1**	**$ 9**
Year Ended December 31, 2016	118	39	40	23	17	3	7	
Year Ended December 31, 2015	142	93	36	28	8	2	6	

(a) Piedmont severance benefit costs were $3 million for the two months ended December 31, 2016, and $19 million for the year ended October 31, 2016. Piedmont did not record any severance benefit costs for the year ended October 31, 2015.

The table below presents the severance liability for past and ongoing severance plans including the plans described above. Amounts for Duke Energy Indiana and Duke Energy Ohio are not material.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Piedmont
Balance at December 31, 2016	$ 79	$ 13	$ 14	$ 6	$ 8	$ 20
Provision/Adjustments	**17**	**2**	**—**	**—**	**—**	**9**
Cash Reductions	**(77)**	**(10)**	**(12)**	**(5)**	**(8)**	**(24)**
Balance at December 31, 2017	**$ 19**	**$ 5**	**$ 2**	**$ 1**	**$ —**	**$ 5**

20. STOCK-BASED COMPENSATION

The Duke Energy Corporation 2015 Long-Term Incentive Plan (the 2015 Plan) provides for the grant of stock-based compensation awards to employees and outside directors. The 2015 Plan reserves 10 million shares of common stock for issuance. Duke Energy has historically issued new shares upon exercising or vesting of share-based awards. However, Duke Energy may use a combination of new share issuances and open market repurchases for share-based awards that are exercised or vest in the future. Duke Energy has not determined with certainty the amount of such new share issuances or open market repurchases.

The following table summarizes the total expense recognized by the Duke Energy Registrants, net of tax, for stock-based compensation.

	Years Ended December 31,		
(in millions)	2017	2016	2015
Duke Energy	**$ 43**	$ 35	$ 38
Duke Energy Carolinas	**15**	12	14
Progress Energy	**16**	12	14
Duke Energy Progress	**10**	7	9
Duke Energy Florida	**6**	5	5
Duke Energy Ohio	**3**	2	2
Duke Energy Indiana	**4**	3	4
Piedmont(a)	**3**		

(a) 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)	2017	2016	2015
Restricted stock unit awards	**$ 41**	$ 36	$ 38
Performance awards	**27**	19	23
Pretax stock-based compensation cost	**$ 68**	$ 55	$ 61
Tax benefit associated with stock-based compensation expense	**$ 25**	$ 20	$ 23
Stock-based compensation costs capitalized	**4**	2	3

RESTRICTED STOCK UNIT AWARDS

Restricted stock unit (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 restricted stock unit awards.

	Years Ended December 31,		
	2017	2016	2015
Shares awarded (in thousands)	**583**	684	524
Fair value (in millions)	**$ 47**	$ 52	$ 41

The following table summarizes information about restricted stock unit awards outstanding.

	Shares (in thousands)	Weighted Average Grant Date Fair Value (per share)
Outstanding at December 31, 2016	1,139	$ 76
Granted	**583**	**80**
Vested	**(553)**	**76**
Forfeited	**(48)**	**78**
Outstanding at December 31, 2017	**1,121**	**78**
Restricted stock unit awards expected to vest	**1,094**	**78**

The total grant date fair value of shares vested during the years ended December 31, 2017, 2016 and 2015 was $42 million, $38 million and $41 million, respectively. At December 31, 2017, Duke Energy had $29 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of twenty-three months.

PERFORMANCE AWARDS

Stock-based performance awards generally vest after three years if performance targets are met.

Performance awards granted in 2017, 2016 and 2015 contain market conditions based on the total shareholder return (TSR) of Duke Energy stock relative to a predefined peer group (relative TSR). These awards are 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 2017, the model used a risk-free interest rate of 1.5 percent, which reflects the yield on three-year Treasury bonds as of the grant date, and an expected volatility of 17.2 percent based on Duke Energy's historical volatility over three years using daily stock prices.

In addition to TSR, performance awards granted in 2017 and 2016 contain a performance condition based on Duke Energy's cumulative adjusted EPS. Performance awards granted in 2017 also contain a performance condition based on the total incident case rate, one of our key employee safety metrics. The actual number of shares issued will range from zero to 200 percent of target shares depending on the level of performance achieved.

The following table includes information related to stock-based performance awards.

	Years Ended December 31,		
	2017	2016	2015
Shares granted assuming target performance (in thousands)	**461**	338	321
Fair value (in millions)	**$ 37**	$ 25	$ 26

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, 2016	862	$ 75
Granted	**461**	**81**
Forfeited	**(258)**	**69**
Outstanding at December 31, 2017	**1,065**	**79**
Stock-based performance awards expected to vest	**1,034**	**79**

No performance awards vested during the year ended December 31, 2017. The total grant date fair value of shares vested during the years ended December 31, 2016 and 2015 was $25 million and $26 million, respectively. At December 31, 2017, Duke Energy had $34 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of twenty-three months.

STOCK OPTIONS

Stock options, when granted, have a maximum option term of 10 years and with an exercise price not less than the market price of Duke Energy's common stock on the grant date. There were no stock options granted or exercised during the year ended December 31, 2017. There were no stock options outstanding at December 31, 2017.

The following table summarizes additional information related to stock options exercised and granted.

	Years Ended December 31,	
(in millions)	**2016**	**2015**
Intrinsic value of options exercised	$ 1	$ 5
Tax benefit related to options exercised	—	2
Cash received from options exercised	7	17

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 Agreement and Plan of Merger (Merger Agreement) between Duke Energy and Piedmont 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 as discussed above 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. Piedmont's stock-based compensation costs were not material for the two months ended December 31, 2016.

	Years Ended October 31,	
(in millions)	**2016**	**2015**
Pretax stock-based compensation cost	$ 16	$ 14
Tax benefit associated with stock-based compensation expense	6	4
Net of tax stock-based compensation cost	$ 10	$ 10

21. 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), (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 is expected to lower 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. However, portions of the net periodic benefit costs disclosed in the tables below have been capitalized as a component of property, plant and equipment. 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 Subsidiary Registrants are allocated 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. 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. 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)
Anticipated Contributions:								
Total anticipated 2018 contributions	$ **148**	$ **46**	$ **45**	$ **25**	$ **20**	$ **—**	$ **8**	$ **7**
Contributions made January 2, 2018	141	46	45	25	20	—	8	—
Contributions to be made in 2018	$ 7	$ —	$ —	$ —	$ —	$ —	$ —	$ 7
Contributions Made:								
2017	$ **19**	$ **—**	$ **—**	$ **—**	$ **—**	$ **4**	$ **—**	$ **11**
2016	155	43	43	24	20	5	9	
2015	302	91	83	42	40	8	19	

(a) Piedmont contributed $10 million to its U.S. qualified defined benefit pension plan during the two months ended December 31, 2016, and for each of the years ended October 31, 2016, and 2015, respectively.

QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	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

	Year Ended December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Service cost	$ 159	$ 50	$ 44	$ 23	$ 20	$ 4	$ 10
Interest cost on projected benefit obligation	324	83	104	48	54	18	27
Expected return on plan assets	(516)	(139)	(171)	(79)	(87)	(26)	(42)
Amortization of actuarial loss	166	39	65	33	31	7	13
Amortization of prior service (credit) cost	(15)	(7)	(3)	(2)	(1)	—	1
Other	8	2	3	1	1	—	1
Net periodic pension costs(a)(b)	$ 126	$ 28	$ 42	$ 24	$ 18	$ 3	$ 10

(a) Duke Energy amounts exclude $7 million, $8 million and $9 million for the years ended December 2017, 2016 and 2015, 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 $3 million, $4 million and $4 million for the years ended December 2017, 2016 and 2015, 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	Years Ended October 31,	
(in millions)	December 31, 2016	2016	2015
Service cost	$ 2	$ 11	$ 11
Interest cost on projected benefit obligation	2	9	12
Expected return on plan assets	(4)	(24)	(24)
Amortization of actuarial loss	2	8	9
Amortization of prior service credit	(1)	(2)	(2)
Settlement charge	3	—	—
Net periodic pension costs	$ 4	$ 2	$ 6

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets

	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 loss (income)								
Deferred income tax expense	**$ —**	**—**	**3**	**—**	**—**	**—**	**—**	**—**
Prior year service cost arising during the year	**1**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Amortization of prior year actuarial losses	**(7)**	**—**	**(7)**	**—**	**—**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive income	**$ (6)**	**$ —**	**$ (4)**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

	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**
Regulatory assets, net increase	$ 214	$ 4	$ 34	$ 18	$ 16	$ 2	$ 9
Accumulated other comprehensive (income) loss							
Deferred income tax expense	$ 4	$ —	$ —	$ —	$ —	$ —	$ —
Prior year service credit arising during the year	(2)	—	—	—	—	—	—
Amortization of prior year actuarial losses	(7)	—	(1)	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ (5)	$ —	$ (1)	$ —	$ —	$ —	$ —

Piedmont's regulatory asset net increase was $34 million, $35 million and $20 million for the two months ended December 31, 2016, and for the years ended October 31, 2016, and 2015, respectively.

Reconciliation of Funded Status to Net Amount Recognized

	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

	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**
Change in Projected Benefit Obligation							
Obligation at prior measurement date	$ 7,727	$ 1,995	$ 2,451	$ 1,143	$ 1,276	$ 453	$ 649
Obligation assumed from acquisition	352	—	—	—	—	—	—
Service cost	147	48	42	24	19	4	9
Interest cost	335	86	106	49	55	19	28
Actuarial loss	307	46	111	52	57	13	41
Transfers	—	14	(3)	(3)	—	(3)	—
Plan amendments	(52)	(3)	—	—	—	(3)	(15)
Benefits paid	(679)	(234)	(195)	(107)	(84)	(36)	(54)
Impact of settlements	(6)	—	—	—	—	—	—
Obligation at measurement date	$ 8,131	$ 1,952	$ 2,512	$ 1,158	$ 1,323	$ 447	$ 658
Accumulated Benefit Obligation at measurement date	$ 8,006	$ 1,952	$ 2,479	$ 1,158	$ 1,290	$ 436	$ 649
Change in Fair Value of Plan Assets							
Plan assets at prior measurement date	$ 8,136	$ 2,243	$ 2,640	$ 1,284	$ 1,321	$ 433	$ 655
Assets received from acquisition	343	—	—	—	—	—	—
Employer contributions	155	43	43	24	20	5	9
Actual return on plan assets	582	159	190	92	95	29	47
Benefits paid	(679)	(234)	(195)	(107)	(84)	(36)	(54)
Impact of settlements	(6)	—	—	—	—	—	—
Transfers	—	14	(3)	(3)	—	(3)	—
Plan assets at measurement date	$ 8,531	$ 2,225	$ 2,675	$ 1,290	$ 1,352	$ 428	$ 657
Funded status of plan	$ 400	$ 273	$ 163	$ 132	$ 29	$ (19)	$ (1)

	Piedmont	
	Two Months Ended	Years Ended
(in millions)	**December 31, 2016**	**October 31, 2016**
Change in Projected Benefit Obligation		
Obligation at prior measurement date	$ 352	$ 312
Service cost	2	11
Interest cost	2	9
Actuarial gain	(5)	34
Benefits paid	(1)	(14)
Impact of settlements	(6)	—
Obligation at measurement date	$ 344	$ 352
Accumulated Benefit Obligation at measurement date	$ 289	$ 296
Change in Fair Value of Plan Assets		
Plan assets at prior measurement date	$ 343	$ 329
Employer contributions	10	10
Actual return on plan assets	—	18
Benefits paid	(1)	(14)
Impact of settlements	(6)	—
Plan assets at measurement date	$ 346	$ 343
Funded status of plan	$ 2	$ (9)

Amounts Recognized in the Consolidated Balance Sheets

	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 (liability) 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)

	December 31, 2016							
(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]	$ 518	$ 273	$ 225	$ 132	$ 91	$ 6	$ —	3
Noncurrent pension liability[b]	$ 118	$ —	$ 62	$ —	$ 62	$ 25	$ 1	—
Net asset recognized	$ 400	$ 273	$ 163	$ 132	$ 29	$ (19)	$ (1)	$ 3
Regulatory assets	$ 2,098	$ 476	$ 805	$ 378	$ 426	$ 81	$ 171	$ 137
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (41)	$ —	$ (6)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(6)	—	—	—	—	—	—	—
Net actuarial loss	123	—	16	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 76	$ —	$ 10	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension costs in the next year								
Unrecognized net actuarial loss	$ 147	$ 31	$ 52	$ 23	$ 29	$ 5	$ 8	$ 13
Unrecognized prior service credit	$ (24)	$ (8)	$ (3)	$ (2)	$ (1)	$ —	$ (2)	$ (2)

(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, 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**

	December 31, 2016			
(in millions)	Duke Energy	Progress Energy	Duke Energy Florida	Duke Energy Ohio
Projected benefit obligation	$ 1,299	$ 665	$ 665	$ 311
Accumulated benefit obligation	1,239	633	633	299
Fair value of plan assets	1,182	604	604	286

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 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 nine years for Piedmont.

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

	December 31,		
	2017	**2016**	**2015**
Benefit Obligations			
Discount rate	**3.60%**	4.10%	4.40%
Salary increase	**3.50% – 4.00%**	4.00% – 4.50%	4.00% – 4.40%
Net Periodic Benefit Cost			
Discount rate	**4.10%**	4.40%	4.10%
Salary increase	**4.00% – 4.50%**	4.00% – 4.40%	4.00% – 4.40%
Expected long-term rate of return on plan assets	**6.50% – 6.75%**	6.50% – 6.75%	6.50%

	Piedmont		
	Two Months Ended	Years Ended October 31,	
	December 31, 2016	2016	2015
Benefit Obligations			
Discount rate	4.10%	3.80%	4.34%
Salary increase	4.50%	4.05%	4.07%
Net Periodic Benefit Cost			
Discount rate	3.80%	4.34%	4.13%
Salary increase	4.05%	4.07%	3.68%
Expected long-term rate of return on plan assets	6.75%	7.25%	7.50%

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,								
2018	$ 642	$ 185	$ 161	$ 85	$ 75	$ 36	$ 47	$ 29
2019	644	185	164	86	77	36	46	26
2020	661	195	172	90	80	36	44	24
2021	666	194	175	93	81	37	44	24
2022	672	197	176	92	83	36	44	23
2023-2027	3,099	865	888	449	435	166	210	103

NON-QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	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	**$ 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	Duke Energy Ohio	Duke Energy Indiana
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	$ —	$ —

	Year Ended December 31, 2015						
(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	$ —	$ —	$ —	$ —
Interest cost on projected benefit obligation	13	1	4	1	2	—	—
Amortization of actuarial loss	6	—	2	1	2	—	1
Amortization of prior service credit	(1)	—	(1)	—	—	—	—
Net periodic pension costs	$ 21	$ 1	$ 6	$ 2	$ 4	$ —	$ 1

	Piedmont	
	Years Ended October 31,	
(in millions)	2016	2015
Amortization of prior service cost	$ —	$ 1
Settlement charge	1	—
Net periodic pension costs	$ 1	$ 1

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

	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	**$ 5**	**$ (1)**	**$ 3**	**$ 1**	**$ 2**	**$ —**	**$ —**	**$ —**
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	**$ (1)**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Actuarial loss arising during the year	**2**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive loss (income)	**$ 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
Regulatory assets, net (decrease) increase	$ (3)	$ (2)	$ 2	$ 1	$ 1	$ —	$ (1)
Accumulated other comprehensive (income) loss							
Prior service credit arising during the year	$ (1)	$ —	$ —	$ —	$ —	$ —	$ —
Actuarial gains arising during the year	1	—	—	—	—	—	—
Net amount recognized in accumulated other comprehensive loss (income)	$ —	$ —	$ —	$ —	$ —	$ —	$ —

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, 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 losses (gains)	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	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
	Year Ended December 31, 2016						
Change in Projected Benefit Obligation							
Obligation at prior measurement date	$ 341	$ 16	$ 112	$ 33	$ 46	$ 4	$ 5
Obligation assumed from acquisition	5	—	—	—	—	—	—
Service cost	2	—	—	—	—	—	—
Interest cost	14	1	5	1	2	—	—
Actuarial losses (gains)	4	(1)	5	2	1	—	(2)
Plan amendments	(2)	—	—	—	—	—	
Benefits paid	(32)	(2)	(8)	(3)	(3)	—	—
Obligation at measurement date	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3
Accumulated Benefit Obligation at measurement date	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3
Change in Fair Value of Plan Assets							
Benefits paid	$ (32)	$ (2)	$ (8)	$ (3)	(3)	—	—
Employer contributions	32	2	8	3	3	—	—
Plan assets at measurement date	$ —	$ —	$ —	$ —	$ —	$ —	$ —

	Piedmont	
	Two Months Ended	Years Ended
(in millions)	**December 31, 2016**	**October 31, 2016**
Change in Projected Benefit Obligation		
Obligation at prior measurement date	$ 5	$ 6
Actuarial gain	(1)	—
Impact of settlements	—	(1)
Obligation at measurement date	$ 4	$ 5
Accumulated Benefit Obligation at measurement date	$ —	$ 5
Change in Fair Value of Plan Assets		
Plan assets at prior measurement date	$ —	$ 1
Impact of settlements	—	(1)
Plan assets at measurement date	$ —	$ —

Amounts Recognized in the Consolidated Balance Sheets

	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)	—	—	—	—	—	—	—

	December 31, 2016							
(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]	$ 28	$ 2	$ 8	$ 2	$ 3	$ —	$ —	$ —
Noncurrent pension liability[b]	304	12	106	31	43	4	3	4
Total accrued pension liability	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3	$ 4
Regulatory assets	$ 73	$ 5	$ 18	$ 7	$ 11	$ 1	$ —	$ 1
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (3)	$ —	$ (3)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(1)	—	—	—	—	—	—	—
Net actuarial loss	10	—	9	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 6	$ —	$ 6	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	$ 7	$ —	$ 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, 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**

	December 31, 2016							
(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	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3	$ 4
Accumulated benefit obligation	332	14	114	33	46	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 11 years for Duke Energy and Duke Energy Progress, 14 years for Progress Energy, 15 years for Duke Energy Florida, eight years for Duke Energy Carolinas, Duke Energy Ohio, and Duke Energy Indiana, and nine years for Piedmont. The following tables present the assumptions used for pension benefit accounting.

	December 31, 2017	2016	2015
Benefit Obligations			
Discount rate	**3.60%**	4.10%	4.40%
Salary increase	**3.50% – 4.00%**	4.40%	4.40%
Net Periodic Benefit Cost			
Discount rate	**4.10%**	4.40%	4.10%
Salary increase	**4.40%**	4.40%	4.40%

	Piedmont Two Months Ended December 31, 2016	Years Ended October 31, 2016	2015
Benefit Obligations			
Discount rate	4.10%	3.80%	3.85%
Net Periodic Benefit Cost			
Discount rate	3.80%	3.85%	3.69%

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,								
2018	$ 23	$ 2	$ 8	$ 3	$ 3	$ —	$ —	$ —
2019	21	1	8	2	3	—	—	—
2020	21	1	8	2	3	—	—	—
2021	22	1	8	2	3	—	—	—
2022	25	1	8	2	3	—	—	—
2023-2027	117	6	36	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, 2017, 2016 or 2015.

Components of Net Periodic Other Post-Retirement Benefit Costs

	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

	Year Ended December 31, 2015						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Service cost	$ 6	$ 1	$ 1	$ 1	$ 1	$ —	$ 1
Interest cost on accumulated post-retirement benefit obligation	36	9	15	8	7	2	4
Expected return on plan assets	(13)	(8)	—	—	—	(1)	(1)
Amortization of actuarial loss (gain)	16	(2)	28	18	10	(2)	(2)
Amortization of prior service credit	(140)	(14)	(102)	(68)	(35)	—	—
Net periodic post-retirement benefit costs(a)(b)	$ (95)	$ (14)	$ (58)	$ (41)	$ (17)	$ (1)	$ 2

(a) Duke Energy amounts exclude $7 million, $8 million and $10 million for the years ended December 2017, 2016 and 2015, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

(b) Duke Energy Ohio amounts exclude $2 million, $2 million and $3 million for the years ended December 2017, 2016 and 2015, 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	
	Years Ended October 31,	
(in millions)	**2016**	**2015**
Service cost	$ 1	$ 1
Interest cost on projected benefit obligation	1	2
Expected return on plan assets	(2)	(2)
Amortization of actuarial loss	1	—
Net periodic pension costs	$ 1	$ 1

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

	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**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

	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**
Regulatory assets, net increase (decrease)	$ 53	$ —	$ 47	$ 38	$ 9	$ —	$ (6)
Regulatory liabilities, net increase (decrease)	$ (114)	$ (22)	$ (51)	$ (25)	$ (26)	$ (2)	$ (12)
Accumulated other comprehensive (income) loss							
Deferred income tax benefit	$ (2)	$ —	$ —	$ —	$ —	$ —	$ —
Actuarial losses arising during the year	3	—	—	—	—	—	—
Amortization of prior year prior service credit	1	—	1	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ 2	$ —	$ 1	$ —	$ —	$ —	$ —

Piedmont's regulatory assets net decreased $1 million for the two months ended December 31, 2016, and increased $2 million and $1 million for the years ended October 31, 2016, and 2015, respectively.

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

	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 (gains) losses	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

	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
Change in Projected Benefit Obligation							
Accumulated post-retirement benefit obligation at prior measurement date	$ 828	$ 200	$ 354	$ 188	$ 164	$ 35	$ 87
Obligation assumed from acquisition	39	—	—	—	—	—	—
Service cost	3	1	1	—	1	—	—
Interest cost	35	8	15	8	7	1	4
Plan participants' contributions	19	3	7	4	3	1	2
Actuarial (gains) losses	33	5	16	8	8	—	3
Transfers	—	1	—	—	—	—	—
Plan amendments	(1)	—	—	—	—	(1)	—
Benefits paid	(88)	(17)	(36)	(17)	(19)	(4)	(13)
Accumulated post-retirement benefit obligation at measurement date	$ 868	$ 201	$ 357	$ 191	$ 164	$ 32	$ 83
Change in Fair Value of Plan Assets							
Plan assets at prior measurement date	$ 208	$ 134	$ —	$ —	$ 1	$ 8	$ 19
Assets received from acquisition	29	—	—	—	—	—	—
Actual return on plan assets	14	8	1	—	—	1	2
Benefits paid	(88)	(17)	(36)	(17)	(19)	(4)	(13)
Employer contributions	62	9	29	13	15	1	12
Plan participants' contributions	19	3	7	4	3	1	2
Plan assets at measurement date	$ 244	$ 137	$ 1	$ —	$ —	$ 7	$ 22

	Piedmont			
	Two Months Ended		Years Ended	
(in millions)	**December 31, 2016**		**October 31, 2016**	
Change in Projected Benefit Obligation				
Accumulated post-retirement benefit obligation at prior measurement date	$	39	$	38
Service cost		—		1
Interest cost		—		1
Actuarial gain		—		2
Benefits paid		—		(3)
Accumulated post-retirement benefit obligation at measurement date	$	39	$	39
Change in Fair Value of Plan Assets				
Plan assets at prior measurement date	$	29	$	28
Employer contributions		—		3
Actual return on plan assets		—		1
Benefits paid		—		(3)
Plan assets at measurement date	$	29	$	29

Amounts Recognized in the Consolidated Balance Sheets

	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	$ 5	$ 3	$ 1	$ —	$ 1	$ —	$ —	$ —
Unrecognized prior service credit	(19)	(5)	(7)	(1)	(6)	(1)	(1)	(2)

	December 31, 2016							
(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)]	$ 38	$ —	$ 31	$ 17	$ 15	$ 2	$ —	$ —
Noncurrent post-retirement liability[(b)]	586	64	325	174	149	23	63	10
Total accrued post-retirement liability	$ 624	$ 64	$ 356	$ 191	$ 164	$ 25	$ 63	$ 10
Regulatory assets	$ 54	$ —	$ 48	$ 38	$ 10	$ —	$ 51	$ 7
Regulatory liabilities	$ 174	$ 46	$ —	$ —	$ —	$ 19	$ 71	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ 5	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit	(5)	—	—	—	—	—	—	—
Net actuarial gain	(10)	—	—	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive income	$ (10)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss (gain)	$ 10	$ (2)	$ 21	$ 12	$ 9	$ (2)	$ (6)	$ —
Unrecognized prior service credit	(115)	(10)	(85)	(55)	(30)	—	(1)	—

(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,		
	2017	2016	2015
Benefit Obligations			
Discount rate	**3.60%**	4.10%	4.40%
Net Periodic Benefit Cost			
Discount rate	**4.10%**	4.40%	4.10%
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	Years Ended October 31,	
	December 31, 2016	2016	2015
Benefit Obligations			
Discount rate	4.10%	3.80%	4.38%
Net Periodic Benefit Cost			
Discount rate	3.80%	4.38%	4.03%
Expected long-term rate of return on plan assets	6.75%	7.25%	7.50%

Assumed Health Care Cost Trend Rate

	December 31,	
	2017	2016
Health care cost trend rate assumed for next year	**7.00%**	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**	2023

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	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
1-Percentage Point Increase								
Effect on total service and interest costs	**$ 1**	**$ —**	**$ 1**	**$ 1**	**$ —**	**$ —**	**$ —**	**$ —**
Effect on post-retirement benefit obligation	**27**	**6**	**11**	**6**	**5**	**1**	**3**	**1**
1-Percentage Point Decrease								
Effect on total service and interest costs	**(1)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Effect on post-retirement benefit obligation	**(24)**	**(6)**	**(10)**	**(5)**	**(5)**	**(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,								
2018	$ 78	$ 17	$ 30	$ 16	$ 14	$ 3	$ 9	$ 2
2019	76	17	29	15	14	3	9	2
2020	73	17	29	15	14	3	8	2
2021	71	17	28	15	13	3	7	3
2022	68	17	27	14	13	3	7	3
2023 – 2027	290	70	117	63	54	12	29	13

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, 2017, and 2016. The investment objective of the Duke Energy Master Retirement Trust is to achieve reasonable returns, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants.

As of December 31, 2017, Duke Energy assumes pension and other post-retirement plan assets will generate a long-term rate of return of 6.50 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. Hedge funds, real estate 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.

In 2013, Duke Energy adopted a de-risking investment strategy for the Duke Energy Master Retirement Trust. As the funded status of the pension plans increase, the targeted allocation to fixed-income assets may be increased to better manage Duke Energy’s pension liability and reduce funded status volatility. Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

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 $195 million and $156 million at December 31, 2017, and 2016, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned at December 31, 2017, and 2016, respectively. Securities lending income earned by the Duke Energy Master Retirement Trust was immaterial for the years ended December 31, 2017, 2016 and 2015, 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, 2017, and the actual asset allocations for the Duke Energy Master Retirement Trust.

	Target Allocation	Actual Allocation at December 31, 2017	Actual Allocation at December 31, 2016(a)
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%

(a) Excludes Piedmont Pension Assets, which had a targeted asset allocation of 60 percent return-seeking and 40 percent liability hedging fixed-income. Actual asset allocations were 61 percent return-seeking and 39 percent liability hedging fixed-income at December 31, 2016.

Other post-retirement assets

Duke Energy's other post-retirement assets are comprised of Voluntary Employees' Beneficiary Association (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, 2017.

	Target Allocation	Actual Allocation at December 31, 2017	Actual Allocation at December 31, 2016
U.S. equity securities	32%	**41%**	39%
Non-US equity securities	6%	**8%**	—%
Real estate	2%	**2%**	2%
Debt securities	45%	**36%**	37%
Cash	15%	**13%**	22%
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, 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 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.

	December 31, 2016				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized(b)**
Equity securities	$ 2,472	$ 1,677	$ 27	$ 9	759
Corporate debt securities	4,330	8	4,322	—	—
Short-term investment funds	476	211	265	—	—
Partnership interests	157	—	—	—	157
Hedge funds	232	—	—	—	232
Real estate limited partnerships	144	17	—	—	127
U.S. government securities	734	—	734	—	—
Guaranteed investment contracts	29	—	—	29	—
Governments bonds – foreign	32	—	32	—	—
Cash	17	15	2	—	—
Net pending transactions and other investments	32	1	6	—	25
Total assets(a)	$ 8,655	$ 1,929	$ 5,388	$ 38	$ 1,300

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana were allocated approximately 27 percent, 30 percent, 15 percent, 15 percent, 5 percent and 8 percent, respectively, of the Duke Energy Master Retirement Trust and Piedmont's Pension assets at December 31, 2016. 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 and Piedmont Pension Assets at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3).

(in millions)	**2017**	**2016**
Balance at January 1	**$ 38**	$ 31
Combination of Piedmont Pension Assets	**—**	9
Sales	**(2)**	(2)
Total gains (losses) and other, net	**1**	—
Transfer of Level 3 assets to other classifications	**(9)**	—
Balance at December 31	**$ 28**	$ 38

Other post-retirement assets

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

	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**

	December 31, 2016	
(in millions)	**Total Fair Value**	**Level 2**
Cash and cash equivalents	$ 14	**$ 14**
Real estate	1	**1**
Equity securities	26	**26**
Debt securities	25	**25**
Total assets	$ 66	$ 66

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 (5 percent for Piedmont employees). 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.

As of January 1, 2014, for new and rehired non-union and certain unionized employees (excludes Piedmont employees until 2018 plan year, discussed below) 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.

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,								
2017	**$ 179**	**$ 61**	**$ 53**	**$ 37**	**$ 16**	**$ 3**	**$ 9**	**$ 7**
2016	169	57	50	35	15	3	8	—
2015	159	54	48	34	13	3	7	—

(a) Piedmont's pretax employer matching contributions were $1 million, $7 million and $7 million during the two months ended December 31, 2016 and for the years ended October 31, 2016 and 2015, respectively.

Money Purchase Pension Plan

Piedmont sponsors the MPP plan, which is a defined contribution pension plan that allows employees to direct investments and assume risk of investment returns. Under the MPP plan, Piedmont annually deposits a percentage of each participant’s pay into an account of the MPP plan. This contribution equals 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 is 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, October 31, 2016 and 2015. 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.

22. INCOME TAXES

Tax Act

On December 22, 2017, President Trump signed the Tax Act into law. Among other provisions, the Tax Act lowers the corporate federal income tax rate from 35 percent to 21 percent and eliminates bonus depreciation for regulated utilities, effective January 1, 2018. The Tax Act also could be amended or subject to technical correction, which could change the financial impacts that were recorded at December 31, 2017, or are expected to be recorded in future periods. The FERC and state utility commissions will determine the regulatory treatment of the impacts of the Tax Act for the Subsidiary Registrants. The Duke Energy Registrants’ future results of operations, financial condition and cash flows could be adversely impacted by the Tax Act, subsequent amendments or corrections or the actions of the FERC, state utility commissions or credit rating agencies related to the Tax Act. Duke Energy is reviewing orders to address the rate treatment of the Tax Act by each state utility commission in which the Subsidiary Registrants operate. See Note 4 for additional information. Beginning in January 2018, the Subsidiary Registrants will defer the estimated ongoing impacts of the Tax Act that are expected to be returned to customers.

As a result of the Tax Act, Duke Energy revalued its existing deferred tax assets and deferred tax liabilities as of December 31, 2017, to account for the estimated future impact of lower corporate tax rates on these deferred tax amounts. For Duke Energy's regulated operations, where the reduction in the net accumulated deferred income tax (ADIT) liability is expected to be returned to customers in future rates, the net remeasurement has been deferred as a regulatory liability. The regulatory liability for income taxes includes the effect of the reduction of the net deferred tax liability including the tax gross-up of the excess accumulated deferred tax liabilities and the effect of the new tax rate on the previous regulatory asset for income taxes. Excess accumulated deferred income taxes are generally classified as either “protected” or “unprotected” under IRS rules. Protected excess ADIT, resulting from accumulated tax depreciation of public utility property, are required to utilize the average rate assumption method under the IRS normalization rules for determining the timing of the return to customers. The majority of the excess ADIT is related to protected amounts associated with public utility property. See Note 4 for additional information on the Tax Act's impact to the regulatory asset and liability accounts.

On December 22, 2017, the SEC staff issued Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act (SAB 118), 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.

Duke Energy recorded a provisional net tax benefit of $112 million related to the Tax Act in the period ending December 31, 2017. This net benefit primarily consists of a net benefit of $534 million due to the remeasurement of deferred tax accounts to reflect the corporate rate reduction impact to net deferred tax balances, a net expense for the establishment of a valuation allowance related to foreign tax credits of $406 million and a transition tax on previously untaxed earnings and profits on foreign subsidiaries of $10 million. 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. Duke Energy recorded a regulatory liability of $8,313 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.

The net provisional charge from deferred tax remeasurement and assessment of valuation allowance is based on currently available information and interpretations which are continuing to evolve. Duke Energy continues to analyze additional information and guidance related to certain aspects of the Tax Act, such as limitations on the deductibility of interest and executive compensation, conformity or decoupling by state legislatures in response to the Tax Act, and the final determination of the net deferred tax liabilities subject to the remeasurement. The prospects of supplemental legislation or regulatory processes to address questions that arise because of the Tax Act, or evolving technical interpretations of the tax law, may also cause the final impact from the Tax Act to differ from the estimated amounts. Duke Energy continues to appropriately refine such amounts within the measurement period allowed by SAB 118, which will be completed no later than the fourth quarter of 2018.

Income Tax Expense

Components of 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 (Net operating loss) 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 the 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.

	Year Ended December 31, 2015						
(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	$ —	$ 216	$ (193)	$ (56)	$ 1	$ (18)	$ (86)
State	(12)	14	1	(4)	(7)	(1)	(12)
Foreign	4	—	—	—	—	—	—
Total current income taxes	(8)	230	(192)	(60)	(6)	(19)	(98)
Deferred income taxes							
Federal	1,097	345	694	334	290	96	245
State	181	57	27	27	58	5	17
Total deferred income taxes(a)	1,278	402	721	361	348	101	262
Investment tax credit amortization	(14)	(5)	(7)	(7)	—	(1)	(1)
Income tax expense from continuing operations	1,256	627	522	294	342	81	163
Tax expense (benefit) from discontinued operations	89	—	(1)	—	—	22	—
Total income tax expense included in Consolidated Statements of Operations	$ 1,345	$ 627	$ 521	$ 294	$ 342	$ 103	$ 163

(a) Includes utilization of NOL carryforwards and tax credit carryforwards of $264 million at Duke Energy, $15 million at Duke Energy Carolinas, $119 million at Progress Energy, $21 million at Duke Energy Progress, $84 million at Duke Energy Florida, $3 million at Duke Energy Ohio and $45 million at Duke Energy Indiana.

	Piedmont		
	Two Months Ended	Years Ended October 31,	
(in millions)	December 31, 2016	2016	2015
Current income taxes			
Federal	$ 4	$ 27	$ (1)
State	(2)	12	1
Total current income taxes	2	39	—
Deferred income taxes			
Federal	24	79	78
State	6	6	12
Total deferred income taxes(a)(b)	30	85	90
Total income tax expense from continuing operations included in Consolidated Statements of Operations	$ 32	$ 124	$ 90

(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.

(b) Includes benefits and utilization of NOL carryforwards of $46 million for the year ended October 31, 2015.

Duke Energy Income from Continuing Operations before Income Taxes

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Domestic(a)	$ **4,207**	$ 3,689	$ 3,831
Foreign	**59**	45	79
Income from continuing operations before income taxes	$ **4,266**	$ 3,734	$ 3,910

(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 (Loss) Income 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, 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.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
	Year Ended December 31, 2016						
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%

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
	Year Ended December 31, 2015						
Income tax expense, computed at the statutory rate of 35 percent	$ 1,369	$ 598	$ 555	$ 302	$ 330	$ 81	$ 168
State income tax, net of federal income tax effect	109	46	18	15	33	2	2
AFUDC equity income	(58)	(34)	(19)	(17)	(3)	(1)	(4)
Renewable energy production tax credits	(72)	—	(1)	—	—	—	—
Audit adjustment	(22)	—	(23)	1	(24)	—	—
Tax true-up	2	2	(3)	(4)	2	(5)	(9)
Other items, net	(72)	15	(5)	(3)	4	4	6
Income tax expense from continuing operations	$ 1,256	$ 627	$ 522	$ 294	$ 342	$ 81	$ 163
Effective tax rate	32.1%	36.7%	32.9%	34.2%	36.3%	35.2%	34.0%

	Piedmont		
	Two Months Ended	Years Ended October 31,	
(in millions)	December 31, 2016	2016	2015
Income tax expense, computed at the statutory rate of 35 percent	$ 30	$ 111	$ 79
State income tax, net of federal income tax effect	1	11	9
Other items, net	1	2	2
Income tax expense from continuing operations	$ 32	$ 124	$ 90
Effective tax rate	37.2%	39.1%	39.7%

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, 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.

As noted above, as a result of the Tax Act, Duke Energy revalued its existing deferred tax assets and liabilities as of December 31, 2017, to account for the estimated future impact of lower corporate tax rates on these deferred amounts. The following table shows the decrease reflected in the net deferred income tax liabilities balance above:

(in millions)	December 31, 2017
Duke Energy	$ 8,982
Duke Energy Carolinas	3,454
Progress Energy	3,282
Duke Energy Progress	1,882
Duke Energy Florida	1,420
Duke Energy Ohio	771
Duke Energy Indiana	1,053
Piedmont	521

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

	December 31, 2017	
(in millions)	Amount	Expiration Year
Investment tax credits	$ 1,406	2024 — 2037
Alternative minimum tax credits	1,147	Refundable by 2021
Federal NOL carryforwards	393	2022 — 2036
State NOL carryforwards and credits[(a)]	296	2018 — 2037
Foreign NOL carryforwards[(b)]	13	2027 — 2036
Foreign Tax Credits[(c)]	1,272	2024 — 2027
Total tax credits and NOL carryforwards	4,527	

(a) A valuation allowance of $90 million has been recorded on the state NOL carryforwards, as presented in the Net Deferred Income Tax Liability Components table.

(b) A valuation allowance of $13 million has been recorded on the foreign NOL carryforwards, as presented in the Net Deferred Income Tax Liability Components table.

(c) A valuation allowance of $416 million has been recorded on the foreign tax credits, as presented in the Net Deferred Income Tax Liability Components table.

	December 31, 2016							
(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	$ 382	$ 66	$ 126	$ 40	$ 93	$ 21	$ 4	$ 71
Capital lease obligations	60	8	—	—	—	—	1	—
Pension, post-retirement and other employee benefits	561	16	199	91	96	22	37	10
Progress Energy merger purchase accounting adjustments[(a)]	918	—	—	—	—	—	—	—
Tax credits and NOL carryforwards	4,682	192	1,165	222	232	49	278	192
Investments and other assets	—	—	—	—	—	3	—	—
Other	205	16	35	8	—	5	9	45
Valuation allowance	(96)	—	(12)	—	—	—	—	(1)
Total deferred income tax assets	6,712	298	1,513	361	421	100	329	317
Investments and other assets	(1,892)	(1,149)	(597)	(313)	(297)	—	(21)	(21)
Accelerated depreciation rates	(14,872)	(4,664)	(4,490)	(2,479)	(2,038)	(1,404)	(1,938)	(1,080)
Regulatory assets and deferred debits, net	(4,103)	(1,029)	(1,672)	(892)	(780)	(139)	(270)	(147)
Total deferred income tax liabilities	(20,867)	(6,842)	(6,759)	(3,684)	(3,115)	(1,543)	(2,229)	(1,248)
Net deferred income tax liabilities	$ (14,155)	$ (6,544)	$ (5,246)	$ (3,323)	$ (2,694)	$ (1,443)	$ (1,900)	$ (931)

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

On August 6, 2015, pursuant to N.C. Gen. Stat. 105-130.3C, the North Carolina Department of Revenue announced the North Carolina corporate income tax rate would be reduced from a statutory rate of 5.0 percent to 4.0 percent beginning January 1, 2016. Duke Energy and Piedmont recorded net reductions of approximately $95 million and $18 million to their North Carolina deferred tax liabilities in the third quarter of 2015. The significant majority of these deferred tax liability reductions were 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.

On August 4, 2016, pursuant to N.C. Gen. Stat. 105-130.3C, the North Carolina Department of Revenue announced the North Carolina corporate income tax rate would be reduced from a statutory rate of 4.0 percent to 3.0 percent beginning January 1, 2017. Duke Energy and Piedmont recorded net reductions of approximately $80 million and $16 million to their North Carolina deferred tax liabilities in the third quarter of 2016. 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.

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 percent 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, 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	—

	Year Ended December 31, 2015					
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana
Unrecognized tax benefits – January 1	$ 213	$ 160	$ 32	$ 23	$ 8	$ 1
Unrecognized tax benefits increases (decreases)						
Gross increases – tax positions in prior periods	—	—	1	1	—	—
Gross decreases – tax positions in prior periods	(48)	(45)	—	—	—	—
Decreases due to settlements	(45)	(43)	—	—	—	—
Reduction due to lapse of statute of limitations	(32)	—	(32)	(21)	(8)	—
Total changes	(125)	(88)	(31)	(20)	(8)	—
Unrecognized tax benefits – December 31	$ 88	$ 72	$ 1	$ 3	$ —	$ 1

The following table includes additional information regarding the Duke Energy Registrants' unrecognized tax benefits at December 31, 2017. During the first quarter of 2018, Duke Energy recognized an approximate $8 million reduction and Duke Energy Carolinas recognized an approximate $1 million reduction in unrecognized tax benefits. No additional material reductions are expected in the next 12 months.

	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
Amount that if recognized, would affect the effective tax rate or regulatory liability[(a)]	**$ 15**	**$ 4**	**$ 7**	**$ 5**	**$ 1**	**$ 1**	**$ 1**	**$ 3**
Amount that if recognized, would be recorded as a component of discontinued operations	**7**	**—**	**—**	**—**	**—**	**2**	**—**	**—**

(a) Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, 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, 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	—

	Year Ended December 31, 2015					
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana
Net interest income recognized related to income taxes	$ 12	$ —	$ 2	$ 2	$ 1	$ 1
Net interest expense recognized related to income taxes	—	1	—	—	—	—
Interest receivable related to income taxes	3	—	—	—	—	3
Interest payable related to income taxes	—	14	—	1	—	—

Piedmont recognized $1 million in net interest income recognized 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.

23. OTHER INCOME AND EXPENSES, NET

The components of Other income and expenses, net on the Consolidated Statements of Operations are as follows. Amounts for Piedmont were not material.

	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**
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	**62**	**3**	**18**	**4**	**11**	**—**	**1**
Other income and expense, net	**$ 352**	**$ 139**	**$ 128**	**$ 65**	**$ 61**	**$ 17**	**$ 37**

	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 (expense), other	36	1	22	6	16	(2)	—
Other income and expense, net	$ 324	$ 162	$ 114	$ 71	$ 44	$ 9	$ 22

	Year Ended December 31, 2015						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Interest income	$ 20	$ 2	$ 4	$ 2	$ 2	$ 4	$ 6
AFUDC equity	164	96	54	47	7	3	11
Post in-service equity returns	73	60	13	13	—	—	—
Nonoperating income (expense), other	33	2	26	9	15	(1)	(6)
Other income and expense, net	$ 290	$ 160	$ 97	$ 71	$ 24	$ 6	$ 11

24. SUBSEQUENT EVENTS

For information on subsequent events related to regulatory matters, commitments and contingencies, debt and credit facilities, investments in unconsolidated affiliates, variable interest entities and common stock see Notes 4, 5, 6, 12, 17 and 18, respectively.

25. QUARTERLY FINANCIAL DATA (UNAUDITED)

DUKE ENERGY

Quarterly EPS amounts may not sum to the full-year total due to changes in the weighted average number of common shares outstanding and rounding.

(in millions, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 5,729**	**$ 5,555**	**$ 6,482**	**$ 5,799**	**$ 23,565**
Operating income	**1,437**	**1,387**	**1,695**	**1,262**	**5,781**
Income from continuing operations	**717**	**691**	**957**	**705**	**3,070**
Loss from discontinued operations, net of tax	**—**	**(2)**	**(2)**	**(2)**	**(6)**
Net income	**717**	**689**	**955**	**703**	**3,064**
Net income attributable to Duke Energy Corporation	**716**	**686**	**954**	**703**	**3,059**
Earnings per share:					
Income from continuing operations attributable to Duke Energy Corporation common stockholders					
Basic	**$ 1.02**	**$ 0.98**	**$ 1.36**	**$ 1.00**	**$ 4.37**
Diluted	**$ 1.02**	**$ 0.98**	**$ 1.36**	**$ 1.00**	**$ 4.37**
Loss from discontinued operations attributable to Duke Energy Corporation common stockholders					
Basic	**$ —**	**$ —**	**$ —**	**$ —**	**$ (0.01)**
Diluted	**$ —**	**$ —**	**$ —**	**$ —**	**$ (0.01)**
Net income attributable to Duke Energy Corporation common stockholders					
Basic	**$ 1.02**	**$ 0.98**	**$ 1.36**	**$ 1.00**	**$ 4.36**
Diluted	**$ 1.02**	**$ 0.98**	**$ 1.36**	**$ 1.00**	**$ 4.36**
2016					
Operating revenues	$ 5,377	$ 5,213	$ 6,576	$ 5,577	$ 22,743
Operating income	1,240	1,259	1,954	888	5,341
Income from continuing operations	577	624	1,001	376	2,578
Income (Loss) from discontinued operations, net of tax	122	(112)	180	(598)	(408)
Net income (loss)	699	512	1,181	(222)	2,170
Net income (loss) attributable to Duke Energy Corporation	694	509	1,176	(227)	2,152
Earnings per share:					
Income from continuing operations attributable to Duke Energy Corporation common stockholders					
Basic	$ 0.83	$ 0.90	$ 1.44	$ 0.53	$ 3.71
Diluted	$ 0.83	$ 0.90	$ 1.44	$ 0.53	$ 3.71
Income (Loss) from discontinued operations attributable to Duke Energy Corporation common stockholders					
Basic	$ 0.18	$ (0.16)	$ 0.26	$ (0.86)	$ (0.60)
Diluted	$ 0.18	$ (0.16)	$ 0.26	$ (0.86)	$ (0.60)

Net income (loss) attributable to Duke Energy Corporation common stockholders					
Basic	$ 1.01	$ 0.74	$ 1.70	$ (0.33)	$ 3.11
Diluted	$ 1.01	$ 0.74	$ 1.70	$ (0.33)	$ 3.11

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (16)**	**$ (30)**	**$ (23)**	**$ (34)**	**$ (103)**
Regulatory Settlements (see Note 4)	**—**	**—**	**(135)**	**(23)**	**(158)**
Commercial Renewables Impairments (see Notes 10 and 11)	**—**	**—**	**(84)**	**(18)**	**(102)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**102**	**102**
Total	**$ (16)**	**$ (30)**	**$ (242)**	**$ 27**	**$ (261)**
2016					
Costs to Achieve Mergers (see Note 2)	$ (120)	$ (111)	$ (84)	$ (208)	$ (523)
Commercial Renewables Impairment (see Note 12)	—	—	(71)	—	(71)
Loss on Sale of International Disposal Group (see Note 2)	—	—	—	(514)	(514)
Impairment of Assets in Central America (see Note 2)	—	(194)	—	—	(194)
Cost Savings Initiatives (see Note 19)	(20)	(24)	(19)	(29)	(92)
Total	$ (140)	$ (329)	$ (174)	$ (751)	$ (1,394)

DUKE ENERGY CAROLINAS

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 1,716**	**$ 1,729**	**$ 2,136**	**$ 1,721**	**$ 7,302**
Operating income	**484**	**485**	**777**	**403**	**2,149**
Net income	**270**	**273**	**466**	**205**	**1,214**
2016					
Operating revenues	$ 1,740	$ 1,675	$ 2,226	$ 1,681	$ 7,322
Operating income	481	464	815	302	2,062
Net income	271	261	494	140	1,166

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (4)**	**$ (6)**	**$ (5)**	**$ (5)**	**$ (20)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**(15)**	**(15)**
Total	**$ (4)**	**$ (6)**	**$ (5)**	**$ (20)**	**$ (35)**
2016					
Costs to Achieve Mergers	$ (11)	$ (12)	$ (13)	$ (68)	$ (104)
Cost Savings Initiatives (see Note 19)	(10)	(10)	(8)	(11)	(39)
Total	$ (21)	$ (22)	$ (21)	$ (79)	$ (143)

PROGRESS ENERGY

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 2,179**	**$ 2,392**	**$ 2,864**	**$ 2,348**	**$ 9,783**
Operating income	**487**	**591**	**657**	**493**	**2,228**
Net income	**201**	**277**	**343**	**447**	**1,268**
Net income attributable to Parent	**199**	**274**	**341**	**444**	**1,258**
2016					
Operating revenues	$ 2,332	$ 2,348	$ 2,965	$ 2,208	$ 9,853
Operating income	475	560	814	292	2,141
Income from continuing operations	212	274	449	104	1,039
Net income	212	274	449	106	1,041
Net income attributable to Parent	209	272	446	104	1,031

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (4)**	**$ (7)**	**$ (6)**	**$ (6)**	**$ (23)**
Regulatory Settlements (see Note 4)	**—**	**—**	**(135)**	**(23)**	**(158)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**246**	**246**
Total	**$ (4)**	**$ (7)**	**$ (141)**	**$ 217**	**$ 65**
2016					
Costs to Achieve Mergers	$ (7)	$ (8)	$ (10)	$ (44)	$ (69)
Cost Savings Initiatives (see Note 19)	(8)	(8)	(10)	(14)	(40)
Total	$ (15)	$ (16)	$ (20)	$ (58)	$ (109)

DUKE ENERGY PROGRESS

(in millions)		First Quarter		Second Quarter		Third Quarter		Fourth Quarter		Total
2017										
Operating revenues	**$**	**1,219**	**$**	**1,199**	**$**	**1,460**	**$**	**1,251**	**$**	**5,129**
Operating income		**286**		**282**		**411**		**256**		**1,235**
Net income		**147**		**154**		**246**		**168**		**715**
2016										
Operating revenues	$	1,307	$	1,213	$	1,583	$	1,174	$	5,277
Operating income		258		255		438		135		1,086
Net income		137		131		271		60		599

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)		First Quarter		Second Quarter		Third Quarter		Fourth Quarter		Total
2017										
Costs to Achieve Piedmont Merger (see Note 2)	**$**	**(2)**	**$**	**(4)**	**$**	**(4)**	**$**	**(4)**	**$**	**(14)**
Regulatory Settlements (see Note 4)		**—**		**—**		**—**		**(23)**		**(23)**
Impacts of the Tax Act (see Note 22)		**—**		**—**		**—**		**40**		**40**
Total	**$**	**(2)**	**$**	**(4)**	**$**	**(4)**	**$**	**13**	**$**	**3**
2016										
Costs to Achieve Mergers	$	(5)	$	(5)	$	(6)	$	(40)	$	(56)
Cost Savings Initiatives (see Note 19)		(5)		(5)		(7)		(6)		(23)
Total	$	(10)	$	(10)	$	(13)	$	(46)	$	(79)

DUKE ENERGY FLORIDA

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 959**	**$ 1,191**	**$ 1,401**	**$ 1,095**	**$ 4,646**
Operating income	**196**	**306**	**240**	**234**	**976**
Net income	**90**	**158**	**120**	**344**	**712**
2016					
Operating revenues	$ 1,024	$ 1,133	$ 1,381	$ 1,030	$ 4,568
Operating income	213	300	373	155	1,041
Net income	110	171	206	64	551

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (2)**	**$ (3)**	**$ (2)**	**$ (2)**	**$ (9)**
Regulatory Settlements (see Note 4)	**—**	**—**	**(135)**	**—**	**(135)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**226**	**226**
Total	**$ (2)**	**$ (3)**	**$ (137)**	**$ 224**	**$ 82**
2016					
Costs to Achieve Mergers	$ (2)	$ (3)	$ (4)	$ (4)	$ (13)
Cost Savings Initiatives (see Note 19)	(2)	(3)	(3)	(9)	(17)
Total	$ (4)	$ (6)	$ (7)	$ (13)	$ (30)

DUKE ENERGY OHIO

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 518**	**$ 437**	**$ 471**	**$ 497**	**$ 1,923**
Operating income	**83**	**65**	**102**	**76**	**326**
Loss from discontinued operations, net of tax	**—**	**—**	**(1)**	**—**	**(1)**
Net income	**42**	**30**	**55**	**65**	**192**
2016					
Operating revenues	$ 516	$ 428	$ 489	$ 511	$ 1,944
Operating income	96	55	106	90	347
Income from discontinued operations, net of tax	2	—	34	—	36
Net income	59	23	89	57	228

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (1)**	**$ (1)**	**$ (2)**	**$ (2)**	**$ (6)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**23**	**23**
Total	**$ (1)**	**$ (1)**	**$ (2)**	**$ 21**	**$ 17**
2016					
Costs to Achieve Mergers	$ (1)	$ (1)	$ (2)	$ (2)	$ (6)
Cost Savings Initiatives (see Note 19)	(1)	(1)	—	(1)	(3)
Total	$ (2)	$ (2)	$ (2)	$ (3)	$ (9)

DUKE ENERGY INDIANA

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 758**	**$ 742**	**$ 802**	**$ 745**	**$ 3,047**
Operating income	**186**	**210**	**230**	**170**	**796**
Net income	**91**	**106**	**121**	**36**	**354**
2016					
Operating revenues	$ 714	$ 702	$ 809	$ 733	$ 2,958
Operating income	176	174	239	176	765
Net income	95	85	129	72	381

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (1)**	**$ (2)**	**$ (2)**	**$ (1)**	**$ (6)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**(55)**	**(55)**
Total	**$ (1)**	**$ (2)**	**$ (2)**	**$ (56)**	**$ (61)**
2016					
Costs to Achieve Mergers	$ (1)	$ (2)	$ (3)	$ (3)	$ (9)
Cost Savings Initiatives (see Note 19)	(1)	(4)	(1)	(1)	(7)
Total	$ (2)	$ (6)	$ (4)	$ (4)	$ (16)

PIEDMONT

The following tables include data for Piedmont's fiscal years ending December 31, 2017, and October 31, 2016.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 500**	**$ 201**	**$ 183**	**$ 444**	**$ 1,328**
Operating income (loss)	**170**	**5**	**(4)**	**115**	**286**
Net income (loss)	**95**	**(8)**	**(11)**	**63**	**139**
2016					
Operating revenues	$ 464	$ 353	$ 160	$ 172	$ 1,149
Operating income (loss)	171	104	—	(50)	225
Net income (loss)	98	63	(7)	39	193

For the two months ended December 31, 2016, Piedmont's operating revenues, operating income, and net income were $322 million, $96 million and $54 million, respectively.

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (6)**	**$ (13)**	**$ (8)**	**$ (19)**	**$ (46)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**2**	**2**
Total	**$ (6)**	**$ (13)**	**$ (8)**	**$ (17)**	**$ (44)**
2016					
Costs to Achieve Mergers	$ (6)	$ (2)	$ (1)	$ (53)	$ (62)

For the two months ended December 31, 2016, Piedmont's costs to achieve merger were $7 million.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	(584,586)			
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	(4,080)			
4	Total (lines 2 and 3)	(4,080)			
5	Balance of Account 219 at End of Preceding Quarter/Year	(588,666)			
6	Balance of Account 219 at Beginning of Current Year	(588,666)			
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	936,642			
8	Current Quarter/Year to Date Changes in Fair Value	(347,977)			
9	Total (lines 7 and 8)	588,665			
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	(10,692,679)		(11,277,265)		
2	1,783,575		1,783,575		
3			(4,080)		
4	1,783,575		1,779,495	1,165,845,688	1,167,625,183
5	(8,909,104)		(9,497,770)		
6	(8,909,104)		(9,497,770)		
7	1,828,661		2,765,303		
8			(347,977)		
9	1,828,661		2,417,326	1,214,747,120	1,217,164,446
10	(7,080,443)		(7,080,444)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	34,818,070,959	34,818,070,959
4	Property Under Capital Leases	39,795,030	39,795,030
5	Plant Purchased or Sold		
6	Completed Construction not Classified	3,396,641,262	3,396,641,262
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	38,254,507,251	38,254,507,251
9	Leased to Others		
10	Held for Future Use	14,834,676	14,834,676
11	Construction Work in Progress	2,610,346,436	2,610,346,436
12	Acquisition Adjustments	284,106	284,106
13	Total Utility Plant (8 thru 12)	40,879,972,469	40,879,972,469
14	Accum Prov for Depr, Amort, & Depl	15,379,235,049	15,379,235,049
15	Net Utility Plant (13 less 14)	25,500,737,420	25,500,737,420
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	14,828,830,111	14,828,830,111
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	550,145,243	550,145,243
22	Total In Service (18 thru 21)	15,378,975,354	15,378,975,354
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	259,695	259,695
33	Total Accum Prov (equals 14) (22,26,30,31,32)	15,379,235,049	15,379,235,049

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
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					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	10,350,294	41,538,916
3	Nuclear Materials	288,884,607	185,818,576
4	Allowance for Funds Used during Construction	37,515,194	14,913,827
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	336,750,095	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		263,827,732
9	In Reactor (120.3)	1,200,997,083	263,827,731
10	SUBTOTAL (Total 8 & 9)	1,200,997,083	
11	Spent Nuclear Fuel (120.4)	556,908,927	306,022,249
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	1,191,832,506	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	902,823,599	
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
	46,332,832	5,556,378	2
	206,692,220	268,010,963	3
	10,802,680	41,626,341	4
			5
		315,193,682	6
			7
	263,827,731	1	8
	306,022,249	1,158,802,565	9
		1,158,802,566	10
	210,682,374	652,248,802	11
			12
-307,787,905	216,028,428	1,283,591,983	13
		842,653,067	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 $210,682,373 of nuclear fuel assemblies and $5,346,055 of nuclear fuel canisters that have been retired.

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	57,923	10,576,105
4	(303) Miscellaneous Intangible Plant	817,492,104	126,626,856
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	817,550,027	137,202,961
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	28,975,500	106,484
9	(311) Structures and Improvements	718,413,983	28,578,799
10	(312) Boiler Plant Equipment	5,224,032,773	112,075,787
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	841,485,181	83,738,535
13	(315) Accessory Electric Equipment	393,310,395	2,633,461
14	(316) Misc. Power Plant Equipment	341,714,240	27,804,041
15	(317) Asset Retirement Costs for Steam Production	1,088,446,411	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	8,636,378,483	254,937,107
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	2,859,427	
19	(321) Structures and Improvements	1,866,620,873	38,287,246
20	(322) Reactor Plant Equipment	3,713,197,436	90,279,561
21	(323) Turbogenerator Units	962,697,290	18,247,171
22	(324) Accessory Electric Equipment	1,130,876,607	42,662,572
23	(325) Misc. Power Plant Equipment	521,232,202	17,320,586
24	(326) Asset Retirement Costs for Nuclear Production	-607,602,839	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	7,589,880,996	206,797,136
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	52,334,298	
28	(331) Structures and Improvements	391,069,965	14,256,246
29	(332) Reservoirs, Dams, and Waterways	821,573,687	13,473,275
30	(333) Water Wheels, Turbines, and Generators	624,498,079	31,251,560
31	(334) Accessory Electric Equipment	142,067,062	4,765,308
32	(335) Misc. Power PLant Equipment	49,236,817	2,064,657
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)	2,102,576,173	65,811,046
36	D. Other Production Plant		
37	(340) Land and Land Rights	9,171,919	
38	(341) Structures and Improvements	338,695,337	17,784,117
39	(342) Fuel Holders, Products, and Accessories	118,324,050	96,378
40	(343) Prime Movers	938,469,619	7,647,495
41	(344) Generators	835,207,801	118,563,791
42	(345) Accessory Electric Equipment	144,271,768	4,854,148
43	(346) Misc. Power Plant Equipment	27,789,928	2,354,200
44	(347) Asset Retirement Costs for Other Production	1,262,479	5,308,834
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,413,192,901	156,608,963
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	20,742,028,553	684,154,252

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	190,365,055	4,932,225
49	(352) Structures and Improvements	83,331,300	21,505,310
50	(353) Station Equipment	1,550,666,028	238,161,973
51	(354) Towers and Fixtures	597,546,563	-31,078,272
52	(355) Poles and Fixtures	408,716,450	103,157,008
53	(356) Overhead Conductors and Devices	733,149,952	2,576,038
54	(357) Underground Conduit	123,868	306
55	(358) Underground Conductors and Devices	4,755,419	1,344,248
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)	3,568,696,873	340,598,836
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	63,784,812	639,110
61	(361) Structures and Improvements	96,166,197	10,214,978
62	(362) Station Equipment	1,264,827,710	70,146,476
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,502,249,254	30,972,827
65	(365) Overhead Conductors and Devices	2,027,364,643	129,728,460
66	(366) Underground Conduit	191,934,666	6,867,716
67	(367) Underground Conductors and Devices	1,841,522,453	91,195,711
68	(368) Line Transformers	1,358,448,611	56,253,174
69	(369) Services	1,008,470,857	41,601,740
70	(370) Meters	464,049,052	153,950,312
71	(371) Installations on Customer Premises	721,223,642	125,369,204
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	212,986,436	16,361,361
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	10,753,028,333	733,301,069
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	34,402,330	28,514,807
87	(390) Structures and Improvements	501,477,987	152,477,284
88	(391) Office Furniture and Equipment	110,861,213	17,165,974
89	(392) Transportation Equipment	10,254,685	2,673,989
90	(393) Stores Equipment	12,954,181	1,024,000
91	(394) Tools, Shop and Garage Equipment	72,782,665	23,133,220
92	(395) Laboratory Equipment	7,510,680	-564,284
93	(396) Power Operated Equipment	14,162,859	262,116
94	(397) Communication Equipment	135,681,865	11,416,493
95	(398) Miscellaneous Equipment	3,803,640	5,852,933
96	SUBTOTAL (Enter Total of lines 86 thru 95)	903,892,105	241,956,532
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)	902,960,770	241,956,532
100	TOTAL (Accounts 101 and 106)	36,784,264,556	2,137,213,650
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)	36,784,264,556	2,137,213,650

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

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
11,262,010			932,856,950		4
11,262,010			943,490,978		5
					6
					7
		-33,444	29,048,540		8
4,373,506			742,619,276		9
34,854,664			5,301,253,896		10
					11
8,224,001			916,999,715		12
1,561,367			394,382,489		13
1,196,523		-8,066,460	360,255,298		14
96,420,548	-192,036,176		799,989,687		15
146,630,609	-192,036,176	-8,099,904	8,544,548,901		16
					17
-23,109			2,882,536		18
19,610,600		-924	1,885,296,595		19
29,659,629		457,560	3,774,274,928		20
4,710,167		-511	976,233,783		21
9,122,159		1,581,302	1,165,998,322		22
1,946,581		-455,924	536,150,283		23
			-607,602,839		24
65,026,027		1,581,503	7,733,233,608		25
					26
			52,334,298		27
2,810,051			402,516,160		28
5,967,382			829,079,580		29
11,015,369			644,734,270		30
3,612,640			143,219,730		31
750,500		-363,304	50,187,670		32
			21,796,265		33
					34
24,155,942		-363,304	2,143,867,973		35
					36
			9,171,919		37
2,891,127			353,588,327		38
-198,655			118,619,083		39
17,371,793			928,745,321		40
1,321,115		-506,749	951,943,728		41
459,498		87,309	148,753,727		42
382,334		201,117	29,962,911		43
			6,571,313		44
22,227,212		-218,323	2,547,356,329		45
258,039,790	-192,036,176	-7,100,028	20,969,006,811		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
-2,054		33,444	195,332,778		48
1,697,366		-20,377	103,118,867		49
21,170,658		-1,063,771	1,766,593,572		50
785,849		3,041,612	568,724,054		51
16,033,770		3,256,925	499,096,613		52
1,711,557		1,891,835	735,906,268		53
			124,174		54
287,393			5,812,274		55
			42,238		56
					57
41,684,539		7,139,668	3,874,750,838		58
					59
225,313			64,198,609		60
1,033,567		20,377	105,367,985		61
16,146,385		-10,984	1,318,816,817		62
					63
6,661,947		7,329	1,526,567,463		64
13,503,859		30,945	2,143,620,189		65
10,352			198,792,030		66
4,852,531			1,927,865,633		67
1,803,479			1,412,898,306		68
783,554			1,049,289,043		69
89,082,595			528,916,769		70
5,343,534			841,249,312		71
					72
1,200,316			228,147,481		73
					74
140,647,432		47,667	11,345,729,637		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			62,917,137		86
6,498,266		-618,354	646,838,651		87
3,765,379			124,261,808		88
2,226,983			10,701,691		89
410,137			13,568,044		90
1,542			95,914,343		91
785,860			6,160,536		92
1,195,300			13,229,675		93
7,819,987			139,278,371		94
66,508			9,590,065		95
22,769,962		-618,354	1,122,460,321		96
					97
			-931,335		98
22,769,962		-618,354	1,121,528,986		99
474,403,733	-192,036,176	-531,047	38,254,507,250		100
					101
					102
					103
474,403,733	-192,036,176	-531,047	38,254,507,250		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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					
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6					
7					
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40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	FURR ROAD RETAIL - HUNTERSVILLE, NC	10/2011	2022	1,227,200
3	GALENOR SUBSTATION - CALDWELL, NC	10/2014	2034	1,000,853
4	NORTH ALEXANDER STREET RETAIL SUB - CHARLOTTE NC	3/2012	2020	959,967
5	LAKE NORMAN 525kv RIGHT OF WAY - CORNELIUS, NC	1/1980	2024	937,983
6	BELMEADE RETAIL LOT - CHARLOTTE, NC	11/2012	2020	804,674
7	KANOY RETAIL LOT - THOMASVILLE, NC	7/2010	2021	575,861
8	BRANSON MILL RD RET - RANDOLPH, NC	11/2013	2022	572,418
9	SHOFFNER RETAIL SUBSTATION - GREENSBORO, NC	12/2009	2019	512,693
10	KERWIN CIRCLE RETAIL - KERNERSVILLE, NC	6/2009	2022	512,463
11	DORMAN ROAD RETAIL - PINEVILLE, NC	6/2012	2020	459,800
12	CALICO ROAD RETAIL - CALDWELL COUNTY, NC	1/2012	2020	427,771
13	MATRIX RETAIL - GREENVILLE, SC	3/2016	2018	415,171
14	REVOLUTION MILL RETAIL SUBSTATION - GREENSBORO, NC	10/2011	2019	400,257
15	HIGHWAY 24 RETAIL - ANDERSON, SC	12/2008	2022	384,198
16	EDGEFIELD RETAIL - GREENSBORO, NC	2/2012	2020	370,486
17	LIBERTY SITE - GILFORD, NC	2/2016	2018	369,643
18	ROEBUCK RETAIL LOT - SPARTANBURG, SC	2/2012	2024	364,453
19	HERMAN RD RETAIL - CATAWBA, NC	4/2016	2025	351,579
20	LONG ISLAND ROAD RETAIL - CATAWBA, NC	5/2009	2022	369,682
21	Other Property:			
22	SKYLAND RETAIL LOT - WINSTON-SALEM, NC	1/1990	2025	303,819
23	KEOWEE PLT PICKENS INSURABLE - SALEM, NC	10/2016	2030	284,915
24	LITTLE MOUNTAIN ROAD RETAIL - GASTONIA, NC	12/2008	2022	282,811
25	Other Land Rights < $250K (63 items)			2,945,979
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47	Total			14,834,676

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	ACCRUALS CAPITAL CLASS - DISTRIBUTION SUBSTATIONS	6,063,853
4	QUARTERLY OBSOLETE S&C CIRCUIT SWITCHERS BUDGET PLUG	5,627,852
5	APPLE INC NEW SUBSTATION	4,390,905
6	WADDELL ROAD RETAIL - TRANSFORMER BANK ADDITION	3,907,855
7	HOLT RETAIL - NEW 100/24/12 KV SUBSTATION	3,777,423
8	CORINTH RETAIL - NEW 44/12.5 KV SUBSTATION	3,382,710
9	BOTANICAL RETAIL - NEW SUBSTATION	3,209,008
10	BUSTER BOYD RETAIL - NEW SUBSTATION	2,212,143
11	DERITA RETAIL - TRANSFORMER BREAKER 1	2,043,591
12	COTTONWOOD RETAIL - TRANSFORMER ADDITION	1,979,550
13	SALISBURY MAIN 0402 RECONDUCTOR 9850	1,882,209
14	NEW CIRCUIT KNIGHTS	1,783,207
15	BIOGEN IMPERIAL AND GENELEE FEEDS	1,677,076
16	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS	1,921,170
17	SOCK HILL RETAIL - NEW SUBSTATION	1,583,322
18	FRONTIER SPINNING TRANSFORM	1,551,731
19	SHATTALON	1,503,734
20	GENESTU DR RETAIL - NEW SUBSTATION	1,460,421
21	CORNING INC TX CHANGE + TX ADDITION	1,432,866
22	ANDALE - ALTERNATE 100KV FEED	1,431,203
23	RUSD DEC SUBSTATION CAPACITY - BREN	1,327,806
24	RUSD JESSUPTOWN RETAIL TRANSFORMER BREAKER CAPACITY	1,292,733
25	RUSD DEC FEEDER CAPACITY - 1ST STREET	1,278,592
26	TOWN CREEK NETWORK TO WESTLAKE	1,274,080
27	FP 20017 TRANSMISSION HB	1,076,343
28	NCDOT U-3633 NC HWY 273 - PCW	1,066,252
29	LOCUST RETAIL 100KV BREAKER ADDITION	1,016,305
30	PROJECTS LESS THAN $1 MILLION	83,066,162
31	TOTAL DISTRIBUTION PLANT $144,220,102	
32		
33	GENERAL PLANT	
34		
35	ELECTRIC BUSINESS SEGMENT - UNIVERSAL PARK CHARLOTTE NC - CUSTOMER SERVICE CENTER	21,170,897
36	CUSTOMER CONNECT FUNDING PROJECT	13,214,933
37	REAL ESTATE SERVICES CAROLINA EAST CAPITAL LOCATIONS	9,086,444
38	GENERAL ACCRUAL FOR DUKE POWER	8,981,842
39	DAILY RATING CHARGING ESTIMATE TOOL	7,195,546
40	PROJECT GATOR INDIRECT FUNDING	5,776,563
41	TELECOM MICROWAVE PROJECTS NC	5,282,729
42	REAL ESTATE SERVICES GENERAL PLANT WORK	4,977,902
43	TOTAL	2,610,346,436

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	CAROLINAS EMS CONSOLIDATION	2,636,874
2	DEE SECURE NETWORK INFRASTRUCTURE	1,999,727
3	TELECOM MICROWAVE PROJECTS POWER DELIVERY	1,607,247
4	PANASONIC UNITS - CAROLINAS EAST	1,580,986
5	SMARTGRID - DEE MDM SCALE FUNDING	1,485,933
6	ESO CW TECHNOLOGY PROJECT	1,462,489
7	REAL ESTATE SERVICES MISCELLANEOUS CAROLINAS WEST GENERAL PLANT PROJECTS	1,393,975
8	TELECOM MICROWAVE PROJECTS SC	1,337,388
9	PROJECTS LESS THAN $1 MILLION	3,796,456
10	TOTAL GENERAL PLANT $92,987,931	
11		
12	INTANGIBLE PLANT	
13		
14	LEE NUCLEAR CONSTRUCTION AND OPERATING LICENSE	308,206,333
15	DAILY RATING CHARGING ESTIMATE TOOL	15,587,331
16	DISTRIBUTED MANAGEMENT SYSTEM PROJECT #3	8,986,971
17	INT657E-CAROLINAS EMS CONSOLIDATION	8,947,507
18	CATAWBA WATEREE RELICENSING VR	7,811,246
19	SMARTGRID DEE DISTRIBUTED MANAGEMENT SYSTEM ADMS	7,539,140
20	SMARTGRID TRANSMISSION OUTAGE APPLICATION REPLACEMENT FUND	4,827,044
21	OCONEE UNIT 1 MEASUREMENT UNCERTAINTY RECAPTURE RATE	4,271,860
22	OCONEE UNIT 3 MEASUREMENT UNCERTAINTY RECAPTURE RATE	3,767,650
23	SMARTGRID DEE TRANSMISSION HEALTH RISK MANAGEMENT	3,254,549
24	OCONEE CORE MONITORING SOFTWARE AND SERVERS	3,159,566
25	OCONEE UNIT 2 MEASUREMENT UNCERTAINTY RECAPTURE RATE	3,130,364
26	ESO - TCC ELECTRONIC MAPBOARD	2,837,128
27	KEOWEE-TOXAWAY RELICENSING NP	2,572,879
28	DEE ADVANCED METERING INFRASTRUCTURE OPS CENTER	1,797,952
29	SMARTGRID DISTRIBUTED MANAGEMENT SYSTEM ENHANCEMENTS	1,665,364
30	ENABLE HARDWARE FOR DEC	1,423,642
31	NUCLEAR MERGER PROJECT 1.1	1,050,902
32	PROJECTS LESS THAN $1 MILLION	4,884,187
33	TOTAL INTANGIBLE PLANT $395,721,615	
34		
35	PRODUCTION PLANT	
36		
37	LEE SITE COMBINED CYCLE	550,248,014
38	LEE NUCLEAR CONSTRUCTION AND OPERATING LICENSE	247,030,266
39	OCONEE UNIT 1 MAIN STREAM ISOLATION VALVES	84,839,113
40	MARSHALL STEAM DRY BOTTOM ASH CONVERSION	55,758,836
41	BELEWS CREEK CCP BC DRY BOTTOM ASH CONVERSION	54,051,215
42	BRIDGEWATER LINVILLE DAM	53,119,528
43	TOTAL	2,610,346,436

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	KEOWEE UNIT 1 GENERATOR STATOR OVERHAUL	42,301,836
2	OMP-LPT REPLACEMENT U3	33,183,809
3	OMP-LPT REPLACEMENT U2	32,555,216
4	MARSHALL ENHANCED FUEL GAS DESULFURIZATION WASTEWATER TREATMEANT	29,374,331
5	MARSHALL STEAM STORM WATER / PROCESS WATER REROUTE	20,954,074
6	ALLEN STEAM DRY BOTTOM ASH CONVERSION	19,777,878
7	MARSHALL STEAM REPLACE 2 LP ROTOR	19,353,671
8	MCGUIRE EMERGENCY SUPPLIMENTAL POWER SOURCE	18,080,170
9	MARSHALL STEAM LINED RETENTION BASIN	17,150,749
10	MARSHALL CELLS 3 AND 4 NEW LANDFILL	15,666,844
11	OCONEE MAIN GENERATOR RELAY PANEL	14,894,361
12	LINED RETENTION BASIN	14,389,216
13	OCONEE ROOF REPLACEMENT TURBINE U1, U2, U3	14,337,003
14	ACTIVE WASTE WATER TREATMENT SYSTEM	13,722,634
15	MARSHALL STEAM 04 SCR INSTALLATION	13,536,829
16	BAD CREEK U2 MW UPRATE	13,437,902
17	BELEWS CREEK CCP STORM WATER / PROCESS WATER REROUTE	13,279,804
18	BELEWS CREEK CCP LINED RETENTION BASIN	13,196,427
19	OCONEE ISFSI PHASE 9 FOUNDATION SLABS AND SECURITY MOD	13,073,807
20	OCONEE UNIT 1 MEASUREMENT UNCERTAINTY RECAPTURE RATE	12,362,522
21	LARK HIGH BAY MAINTENANCE FACILITY	12,084,229
22	CLIFFSIDE 5&6 STORMWATER SURGE BASIN	11,885,276
23	OCONEE SSF GENERATOR REPLACEMENT	11,663,427
24	LEE STEAM WASTE WATER TREATMENT	11,656,246
25	MCGUIRE MAIN STEP-UP TRANSFORMER 2B	11,524,612
26	CLIFFSIDE 6 DUAL FUEL COFIRING	11,112,814
27	OCONEE UNIT 2 MEASUREMENT UNCERTAINTY RECAPTURE RATE	9,446,270
28	OCONEE UNIT 3 MEASUREMENT UNCERTAINTY RECAPTURE RATE	8,967,400
29	OCONEE DRY STORAGE PHASE 8	8,836,804
30	CEDAR CLIFF POWER HOUSE DAM IDF SPILLWAY & GATE HOUSE	8,263,129
31	OCONEE UNIT 1 MAIN STEP UP TRANSFORMER REPLACEMENT	7,860,003
32	CLEMSON COMBINED HEAT AND POWER (CHP) PROJECT	7,548,681
33	OCONEE PLANT SSF LETDOWN LINE MODIFICATION	7,145,706
34	OCONEE NUCLEAR SITE CYBER SECURITY MITIGATION SECURITY SYSTEMS	6,992,001
35	MCGUIRE UNIT 2 MAIN POWER RELAYING	6,892,734
36	COAL HANDLING CONTROL ROOM	6,639,288
37	CLIFFSIDE 5 DUAL FUEL COFIRING	6,597,882
38	CCP ALTERNATE START UP DFA SYSTEM	6,455,587
39	BELLEWS CREEK 02 SECONDARY SH REPLACEMENT	5,872,610
40	ALLEN STEAM STORM WATER / PROCESS WATER REROUTE	5,678,743
41	MCGUIRE LICENSE RENEWAL	5,496,351
42	CLIFFSIDE UNIT 5 - DRY BOTTOM ASH CONVEYING SYSTEM	5,298,070
43	TOTAL	2,610,346,436

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	MARSHALL REPLACE CLARIFIER WITH ULTRAFILTER	5,094,303
2	MCGUIRE INSTALL OPEN PHASE DETECTION	4,861,408
3	OMP-T MCCB MOLDED CASE BREAKERS	4,660,828
4	MARSHALL STEAM UNIT2 HP-IP ROTOR REPLACE	4,505,454
5	UNIT #4 AERATING RUNNER	4,445,778
6	OCONEE RPS/ES ADDITIONAL WORK	4,427,334
7	STORM WATER / PROCESS WATER REROUTE	4,417,434
8	COWANS FORD UNIT 4 LIFE EXTENSION ELECTRICAL	4,288,204
9	CATAWBA - EDG SUPPLEMENTAL POWER SOURCE	4,174,740
10	MCGUIRE NUCLEAR SITE U2 DIGITAL ROD POSITION INDICATION INSTALLATION	3,783,295
11	OCONEE NUCLEAR SITE SPENT FUEL SUPPL COOLING SYSTEM	3,604,707
12	KEOWEE UNIT 2 GENERATOR STAOR OVERHAUL REFURBISH	3,302,220
13	ENHANCED FGD WASTEWATER TREATMENT	3,227,799
14	MCGUIRE UNIT 1 & UNIT 2 POLAR CRANE METER & CONTROLS	3,175,970
15	MCGUIRE PHASE IV DRY STORAGE	3,068,180
16	U2 OPEN PHASE FAULT DETECTION SYSTEM	3,017,400
17	MCGUIRE UNIT 2 D/H TORNADOR MISSLE	3,012,208
18	WOODLEAF SOLAR FACILITY	2,942,513
19	LOOKOUT SHOALS PLANT - SEISMIC NET PROJECT	2,931,069
20	MCGUIRE UNIT 1 DCS SERVER PROJECTOR	2,816,365
21	DEARBORN DIVERSION DAM STRUCTURAL MODIFICATIONS	2,716,571
22	UNIT 2_TRASH RACKS STOP LOGS SYSTEM	2,651,963
23	LINED RETENTION BASINS	2,591,920
24	LINCOLN COMBUSTION TURBINE	2,540,134
25	OMP-T SSF ASW PIPING REPLACEMENT	2,537,389
26	OCONEE NUCLEAR SITE SUPPLEMENTAL LICENSE REQUEST	2,510,734
27	2017 HARDWARE REFRESH	2,510,050
28	CATAWBA NUCLEAR SITE U1 STEAM PATH REPLACEMENT	2,486,187
29	DUKE UNIVERSITY COMBINED HEAR AND POWER (CHP) PROJECT	2,454,375
30	CATAWBA NUCLEAR SITE U2 STEAM PATH REPLACEMENT	2,438,271
31	OCONEE NUCLEAR SITE U2 CYBER SECURITY MITIGATION	2,407,594
32	SSF RCMU PULSATION DAMPENER	2,405,712
33	KEOWEE UNIT 1 ON-LINE MONITORING GENERATOR	2,399,911
34	OCONEE NUCLEAR SITE U3 CYBER SECURITY MITIGATION	2,363,803
35	OCONEE NUCLEAR SITE U1 CYBER SECURITY MITIGATION	2,351,728
36	OCONEE SSF SUMP PUMP/PIPING REPLACING	2,337,004
37	MCGUIRE UNIT 1 GENERATOR STATOR REFURBISHMENT	2,329,311
38	CLIFFSIDE UNIT 5 BIOREACTOR WASTE WATER TREATMENT	2,202,219
39	PURCHASE LAND AROUND LANDFILL	2,182,164
40	OMP-T SSF LETDOWN LINE U3	2,175,663
41	CATAWBA OUTER VBS&OCA CAMERA STANDARDIZATION	2,073,169
42	MARSHALL STEAM SMART M&D PHASE 2 & 3 INSTALL	2,053,633
43	TOTAL	2,610,346,436

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	OCONEE UNITS 1,2 AND 3 LED LIGHT FIXTURES IN TURBINE BUILDING	2,052,211
2	MCGUIRE UNIT 2 DCS SERVER PROJECTOR	2,036,443
3	COWANS FORD UNIT 4 LIFE EXTENSION MECHANICAL	1,895,691
4	TELECOM NUCLEAR FUNDING	1,837,691
5	OCONEE NUCLEAR SITE SIMULATOR SOFTWARE	1,827,107
6	ONP-KEOWEE ON-LINE MONITORING U2	1,818,803
7	MCGUIRE NUCLEAR SITE BULLET-RESISTANT ENCLOSURE	1,764,050
8	OMP-T FWHTR ACCUMULATORS U3	1,763,007
9	OMP-AB CHILLERS	1,751,672
10	MCGUIRE UNIT 2 RN SUCTION OVERPRESSURE PROTECTION SYSTEM	1,738,911
11	OCONEE NUCLEAR SITE COMPLEX REFURBISH 2ND FLOOR	1,625,874
12	MCGUIRE UNIT 1 RN SUCTION OVERPRESSURE PROTECTION	1,609,359
13	COWANS FORD UNIT 1 LIFE EXTENSION GENERATOR COVER AND HEADGATES	1,583,962
14	MOUNTAIN ISLAND DAM SEISMIC	1,553,751
15	CAPITAL LEASE GAS LINE HEATERS	1,539,822
16	AS05 - SOOTBLOWER PROJECT	1,495,764
17	HCAD TRIPPER ROOM VENTILATION	1,450,104
18	RK01 STACK SILENCERS	1,411,091
19	MCGUIRE UNIT 1- 4 ROTORK NA2 ACTUATOR REPLACEMENT	1,392,608
20	OCONEE NUCLEAR SITE CYBERSECURITY MITIGATION COMMON	1,365,023
21	U2 4 ROTORK NA2 ACTUATOR	1,360,094
22	PSCS HARDWARE/SOFTWARE REPLACEMENT	1,312,552
23	CLIFFSIDE 6 MISCELANEOUS CAPITAL VALVES BLANKET	1,285,730
24	UNIT 2 INLINE HYDROGEN GAS MONITOR	1,250,133
25	NANTAHALA HYDRO - PENSTOCK COATINGS FOR WHITE OAK PIPELINE	1,237,157
26	MCGUIRE UNIT 2 RV SHROUD REPLACEMENT	1,202,378
27	VERTICAL BORING MILL	1,173,611
28	OCONEE NUCLEAR SITE 1B2 RCP SEAL (2018)	1,169,974
29	ANHYDROUS AMMONIA PSM CLASS 2 SAFE HAVENS	1,123,840
30	WATEREE U3 GENERATOR BREAKER 3GCB	1,111,521
31	HCAD - COAL CRUSHER MOTORS	1,100,172
32	COWANS FORD LIFE EXTENSION COMMON MECHANICAL	1,049,536
33	BUCK CT CCP PROCESS WATER REROUTE	1,025,504
34	PROJECTS LESS THAN $1 MILLION	73,430,053
35	TOTAL PRODUCTION PLANT $1,864,415,831	
36		
37	TRANSMISSION PLANT	
38		
39	NOTTOWAY SECURITY ENHANCEMENT	10,873,663
40	UNION 100KV LINE REBUILD	10,413,027
41	TUXEDO A&B KV LINE REBUILD PHASE II	8,308,406
42	MCGUIRE UNIT 1B MSU TRANSFORMER	7,915,596
43	TOTAL	2,610,346,436

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	OCONEE 230KV PCB'S REPLACEMENT	7,902,818
2	OWEN SECURITY ENHANCEMENT	7,431,107
3	WINECOFF BANK 1	5,718,421
4	E SPARTENBURG TIE - RELAY	3,774,049
5	MARSHALL STEAM STATION 230-44KV	3,208,120
6	ANDALE - ALTERNATE 100KV FEED	3,039,248
7	MAYO SECURITY ENHANCEMENT	2,959,971
8	LEE NUCLEAR TRANSMISSION ASSETS	2,434,258
9	TOWN CREEK NETWORK TO WESTLAKE	2,221,517
10	CABIN CREEK 44KV LINE REBUILD	2,113,378
11	OAKBORO BANK 4 ADDITION	1,682,755
12	ALAMANCE LINE	1,461,895
13	BELEWS CREEK_RURAL HALL B&W TU	1,408,929
14	OPGW - MARSHALL 230 KV TRANSMISSION LINES	1,107,870
15	PROJECTS LESS THAN $1 MILLION	29,025,929
16	TOTAL TRANSMISSION PLANT $113,000,957	
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43	TOTAL	2,610,346,436

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	14,286,182,243	14,286,182,243		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	984,369,327	984,369,327		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,236,368	1,236,368		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	92,044,977	92,044,977		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,077,650,672	1,077,650,672		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	463,141,721	463,141,721		
13	Cost of Removal	128,984,666	128,984,666		
14	Salvage (Credit)	28,639,672	28,639,672		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	563,486,715	563,486,715		
16	Other Debit or Cr. Items (Describe, details in footnote):	28,483,911	28,483,911		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	14,828,830,111	14,828,830,111		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	3,364,852,908	3,364,852,908		
21	Nuclear Production	3,226,067,944	3,226,067,944		
22	Hydraulic Production-Conventional	294,538,252	294,538,252		
23	Hydraulic Production-Pumped Storage	672,022,673	672,022,673		
24	Other Production	814,261,336	814,261,336		
25	Transmission	1,403,966,062	1,403,966,062		
26	Distribution	4,657,540,019	4,657,540,019		
27	Regional Transmission and Market Operation				
28	General	395,580,917	395,580,917		
29	TOTAL (Enter Total of lines 20 thru 28)	14,828,830,111	14,828,830,111		

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

ARO Depreciation Deferral	$111,712,120
SC EDP Deferral Giveback	$2,064,699
Amortization - Cliffside 6 (contra)	($9,622,692)
Depreciation Deferral - McGuire uprate	($362,760)
Depreciation Deferrals - Dan River	($2,720,688)
Depreciation Deferrals - Solar	$324,548
TEP Impairment Amortization	$618,500
Depreciation Reclassification	($19,126)
Buck & Riverbend Amortization - NBV & Inventory	($9,767,220)
Buck & Bridgewater Amortization	($945,324)
WWII Amortization	($75,977)
Rotable Fleet Spare Amortization	($1,548,845)
Depreciation Deferral on SC AMI Meters	$2,387,742
Total	$92,044,977

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

NBV of Retired NC/SC Meters to Reg Asset	$29,307,533
Gain/Loss	($665,201)
RFS Transfer	($125,616)
Transfers and Adjustments	($32,805)
Total	$28,483,911

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	6/30/1970		
2	Common Stock + Investment in Sub Equity			8,282,949
3	Undistributed Earnings			-3,502,255
4	Advances (open accounts)			
5	Subtotal The Eastover Companies			4,780,694
6				
7	Claiborne Energy Services, Inc.	3/01/1990		
8	Common Stock + Investment in Sub Equity			3,917,479
9	Undistributed Earnings			2,623,205
10	Advances (open accounts)			
11	Subtotal Claiborne Energy Services, Inc.			6,540,684
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	Total Cost of Account 123.1 $ 0		TOTAL	11,321,378

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		8,282,949		2
-21,341		-3,523,596		3
				4
-21,341		4,759,353		5
				6
				7
		3,917,479		8
1,814,033		4,437,238		9
				10
1,814,033		8,354,717		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
1,792,692		13,114,070		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	290,783,909	229,301,332	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)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	597,521,349	555,915,158	Electric
8	Transmission Plant (Estimated)	51,456,333	49,052,803	Electric
9	Distribution Plant (Estimated)	70,924,830	92,574,165	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)	719,902,512	697,542,126	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	56,950	71,125	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	43,768,488	44,420,013	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	1,054,511,859	971,334,596	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	1,008,906.00	435,020	172,130.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	6,623.00			
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	20,591.00	5,450		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	994,938.00	429,570	172,130.00	
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)		130		
45	Gains		130		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
137,539.00		138,060.00		3,587,331.00		5,043,966.00	435,020	1
								2
								3
				138,236.00		144,859.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						20,591.00	5,450	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
137,539.00		138,060.00		3,725,567.00		5,168,234.00	429,570	29
								30
								31
								32
								33
								34
								35
4,130.00		4,130.00		111,510.00		128,030.00		36
								37
								38
						4,130.00		39
4,130.00		4,130.00		111,510.00		123,900.00		40
								41
								42
								43
					31		161	44
					31		161	45
								46

Schedule Page: 228 Line No.: 1 Column: b

Pg 228a 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

Pg 228a 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

Pg 228a Line No. 18 Column c

Does not include the $13,635,107 for renewable energy credits consumption expense represented in account 0509213.

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

Pg 228a 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

Pg 228a 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

Pg 229a Line No. 29 Column m

Does not include the $38,260,073 for renewable energy credits represented in account 0158120.

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

Pg 228a Line No. 39 Column b

Represents allowances withheld in 2017 sold at auction.

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

Pg 229a Line No. 44 Column m

Represents 2017 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	34,700.00	9,779	22,383.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,043.00			
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	20,887.00	-30		
19	Other:				
20	Reallocation of OZone EAs	1,214.00			
21	Cost of Sales/Transfers:				
22	Sales (see notes)	5,500.00	4,530		
23					
24					
25					
26					
27					
28	Total	5,500.00	4,530		
29	Balance-End of Year	8,142.00	5,279	22,383.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		271,000		
34	Gains		266,470		
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.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						57,083.00	9,779	1
								2
								3
						1,043.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						20,887.00	-30	18
								19
						1,214.00		20
								21
						5,500.00	4,530	22
								23
								24
								25
								26
								27
						5,500.00	4,530	28
						30,525.00	5,279	29
								30
								31
								32
							271,000	33
							266,470	34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

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

Pg 228b Line No. 18 Column c

Does not include the $13,635,107 for renewable energy credits consumption expense represented in account 0509213.

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

Pg 228b Line No. 22 Column a

Counterparty	Quantity	COGS	Gain on Sale
Monongahela Power Company	500	$0	$3,500
American Electric Cooperative	1,500	$0	$7,500
Associated Electric Cooperative	2,000	$0	$5,000
Koch Supply & Trading	500	$1,510	$73,490
Fathom Energy LLC	1,000	$3,020	$176,980
	5,500	$4,530	$266,470

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

Pg 228b Line No. 29 Column c

Does not include the $38,260,073 for renewable energy credits represented in account 0158120.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	18,520	0561600		
3	NCEMC Frame Relay Upgrade	939	0561600		
4	CPLW - DUK - SIS	653	0561600		
5	TVA - DUK - SIS	415	0561600		
6	Southern Company - SIS 185MW	415	0561600		
7	DEC - Newberry Solar - SIS	1,244	0561600		
8	Southern Company - SIS 154MV	415	0561600		
9	TVA - DUK - FAC	(231)	0561600		
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	State Studies	(89,430)	0561700		
23					
24	Reidsville - FEA	22,217	0561700		
25	Angus - SIS	2,471	0561700		
26	Hereford - SIS	2,187	0561700		
27	CHP - Duke University - FAC	1,269	0561700		
28	Core Solar - FEA	243	0561700		
29	Simmental Holdings - SIS	2,215	0561700		
30	Core Solar - SIS	588	0561700		
31	Lancaster - SIS	253	0561700		
32	Phoenix - SIS	647	0561700		
33	Birdseye Angus - FAC	381	0561700		
34	Birdseye Hereford - FAC	762	0561700		
35	NTE Reidsville - FAC	1,174	0561700		
36	Birdseye Simmental - FAC	872	0561700		
37	Clemson - SIS	835	0561700		
38	Core Solar - FAC	1,790	0561700		
39	Stanly Solar - SIS	870	0561700		
40	Fresh Air Energy Jonesville - SIS	459	0561700		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

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	Fresh Air Energy Ft. Lawn - SIS	374	0561700		
23	New Town - SIS	161	0561700		
24	Yorkshire Holdings - SIS	460	0561700		
25	Fresh Air Energy Jonesville - FEA	523	0561700		
26	Fresh Air Energy Ft. Lawn - FEA	890	0561700		
27	New Town - FEA	1,153	0561700		
28	Mill Creek - FEA	226	0561700		
29	Iron Works - FEA	52	0561700		
30	Pttsburg - FEA	108	0561700		
31	Richfield - FEA	108	0561700		
32	Bradley Ecoplexus - FEA	226	0561700		
33	Roughedge Ecoplexus - FEA	226	0561700		
34	Kannapolis Ecoplexus - FEA	226	0561700		
35	Oakboro Ecoplexus FEA	226	0561700		
36	Clemson CHP - FAC	5,358	0561700		
37	Clemson CHP - FEA	1,685	0561700		
38	Buck - CC - FEA	452	0561700		
39	Lincoln CT - FAC	474	0561700		
40					

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)	871,261,236	72,217,556	283/282	488,021,666	455,457,126
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	9,250,303	457,022,429	Various	466,272,732	
6						
7	Vacation Accrual					
8	NCUC Docket No. E-7, Sub 774	76,029,245	6,998,745	242		83,027,990
9						
10	Extraordinary Repairs - Thorpe Rewind					
11	Amortized over 25 years					
12	NCUC Docket No. E-13, Sub 166	585,783		545/407	316,209	269,574
13						
14	Retail portion - IRS Section 124 Asset Depreciation	1,926,951		403	75,977	1,850,974
15						
16	Energy Efficiency Cost Recovery - NC					
17	NCUC Dockets No. E-7 Sub 1050	80,508,293	183,407,222	456	112,507,224	151,408,291
18						
19	Renewable Energy and Energy Portfolio					
20	Standard Cost Deferral					
21	NCUC Docket No. E-7, Sub 1052	4,482,011	5,917,582	Various	7,708,657	2,690,936
22						
23	Cliffside Deferral 5 Year Amortization					
24	NCUC Docket No. E-7 Sub 1026					
25	PSC Docket No. 2013-59-E	57,624	633,454	407	691,078	
26						
27	Pension Non-Qualified					
28	NCUC Docket No. E-100, Sub 112	5,139,194		Various	654,783	4,484,411
29						
30	Pension Qualified					
31	NCUC Docket No. E-100, Sub 112	476,399,937	8,393,556	Various	79,412,835	405,380,658
32	Settlement Agreement					
33						
34	Interest Rate Swap					
35	NCUC Docket E-7 Sub 1026					
36	PSC Docket 2013-59-E	93,298,364	9,913,353	431	28,198,569	75,013,148
37						
38	Deferred VOP Expenses					
39	NCUC Docket E-7 Sub 989 - 5 Year Amortization					
40	PSC Order 2012-77 - 3 Year Amortization	1,026,416		407	1,026,416	
41						
42	Natural Gas Hedging - MTM					
43	NCUC Docket E-2 Sub 939					
44	TOTAL	3,019,657,037	1,755,522,992		2,015,081,340	2,760,098,689

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	NCUC Docket E-2 Sub 1049					
2	NCUC Docket E-7 Sub 862					
3	NCUC Docket E-7 Sub 1006					
4	PSC Docket 2015-95-E	22,100	32,103,441	245	22,807,340	9,318,201
5						
6	Pension Deferred Costs					
7	NCUC Docket E-7 Sub 989 - 5 Year Amortization					
8	PSC Order 2012-77 - 3 Year Amortization	232,414		407	232,414	
9						
10	Buck and Bridgewater Deferred Costs					
11	25 Year Amortization					
12	NCUC Docket E-7 Sub 999					
13	PSC Docket 2012-57-E	13,031,213	10,386,748	Various	17,886,872	5,531,089
14						
15	Save-A-Watt Program Deferrals - SC					
16	PSC Docket 2011-420-E	41,848,207	46,305,727	456	29,837,864	58,316,070
17						
18	Dan River & Cliffside 6 Deferred Costs					
19	Dan River - 39 Year Amortization - SC					
20	Dan River - 4 year Amortization - NC					
21	Cliffside 6 - 35 Year Amortization - SC					
22	Cliffside 6 - 4 year Amortization - NC					
23	PSC Docket 2013-99-E					
24	NCUC Docket E-7 Sub 1029	52,404,808	23,504,069	Various	50,277,763	25,631,114
25						
26	McGuire and Oconee Deferred Costs					
27	McGuire - 43 Year Amortization - SC					
28	McGuire - 4 Year Amortization - NC					
29	Oconee - 28 Year Amortization - SC					
30	PSC Docket: 2013-99-E					
31	NCUC Docket E-7 Sub 1029	4,270,218	625,044	Various	1,015,104	3,880,158
32						
33	Fukushima Cybersecurity Def- SC					
34	4 Year Amortization					
35	PSC Order 2013-59-E	123,158	20,916	Various	136,728	7,346
36						
37	Nuclear Levelization					
38	18 -24 Months Amortization					
39	NCUC Docket E-7 Sub 1026					
40	PSC Docket 2013-59-E	91,587,765	273,398,025	Various	281,409,930	83,575,860
41						
42	Billing System Deferral					
43	NCUC Docket E-7 Sub 1026	656,028				656,028
44	TOTAL	3,019,657,037	1,755,522,992		2,015,081,340	2,760,098,689

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	Rate Case Costs					
3	NCUC Docket No. E-7 Sub 909					
4	PSC Docket No. 2009-226-E					
5	NCUC Docket E-7 Sub 989					
6	PSC Docket No. 2011-271-E, Order No. 2012-77	3,123,427		928	488,078	2,635,349
7						
8	Coal Ash Basin - ARO Deferral					
9	NC Coal Ash Management Act of 2014					
10	Consent Agreement with SCDHEC	1,072,340,527	210,834,311	Various	280,849,081	1,002,325,757
11						
12	Coal Ash Remediation Costs					
13	PSC Docket No. 2016-196-E	101,991,131	223,796,447	Various	127,565,702	198,221,876
14						
15	Deferred Fuel					
16	PSCSC Docket 2014-3-E		42,033,735	254/407	6,206,158	35,827,577
17						
18	Deferred Fuel					
19	NCUC Docket E-7 Sub 1033		104,749,280	254/407		104,749,280
20						
21	NCUC Regulatory Fee					
22	NCUC Docket M-100, Sub 142	1,620,363	1,003,730	Various		2,624,093
23						
24	SC Distributed Energy Resource Program					
25	PSC Docket No. 2015-3-E	10,452,961	30,843,678	Various	5,320,562	35,976,077
26						
27	Rotable Fleet Spare					
28	NCUC Docket E-2, Sub 998A					
29	NCUC Docket E-7, Sub 986A					
30	PSC Docket 2015-293-E	2,867,186	645,665	403	1,548,845	1,964,006
31						
32	Advanced Metering Infrastructure					
33	PSC Docket No. 2016-240-E	3,120,174	10,768,279	421	4,612,753	9,275,700
34						
35	Other Deferred Costs					
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	3,019,657,037	1,755,522,992		2,015,081,340	2,760,098,689

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Demand Side Management	-4,030,470	721,777	456, 421	882,284	-4,190,977
2	Costs					
3						
4	Deferred Benefit Plan	64,827		253	25,371	39,456
5						
6	Renewables	-779,605	689,240	Various	1,133,858	-1,224,223
7						
8	I & D Insurance Receivable	587,016,556	15,289,642	131	17,251,637	585,054,561
9						
10	Deferred Coal Ash Remediation					
11	Costs	362,165,755	237,829,351	Various	155,459,868	444,535,238
12						
13	Catawba-Wateree Relicensing					
14	Future Liabilities	8,098,911		107, 253	8,098,911	
15						
16	Meter Retirement Costs		29,300,495			29,300,495
17						
18	Equity Return on BPM Sharing					
19	Rec	1,315,669	286,697	421	595,914	1,006,452
20						
21	Pension/OPEB - Post Retirement	-109,338	320,500			211,162
22						
23	Combustion Turbine Generator					
24	Deferral	19,248,000		131	5,021,973	14,226,027
25						
26	Retired Plant Cost	39,072,372		403	9,767,220	29,305,152
27						
28	Pooled Inventory	4,534,508				4,534,508
29						
30	Cost of Removal Retail Rate					
31	Mitigation	102,794,000				102,794,000
32						
33	Miscellaneous	-29,354	47,076,872	Various	47,047,876	-358
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	643,348				340,195
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)	11,010	2,783,817			2,794,827
49	TOTAL	1,120,016,189				1,208,726,515

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3			
4			
5			
6			
7	Other	2,430,375,077	2,228,934,720
8	TOTAL Electric (Enter Total of lines 2 thru 7)	2,430,375,077	2,228,934,720
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	290,181,179	263,367,548
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	2,720,556,256	2,492,302,268

Notes

Schedule Page: 234 Line No.: 17 Column: a

Primarily relates to deferred taxes on deferral of tax credits and tax credit grossups.

Schedule Page: 234 Line No.: 18 Column: c

The ending balance reflects the following impacts of the Tax Cuts and Jobs Act:

(a) 934,472,872 - Decrease due to the estimated remeasurement of the existing deferred tax assets to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent.

(b) 739,892,043 - Increase due to the gross up recorded on estimated net excess deferred federal income taxes. The estimated net excess deferred federal income taxes resulted from the remeasurement of existing net deferred tax liabilities to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
						3
						4
						5
						6
						7
						8
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						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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, 2017	3,725,067,453
19		
20		
21		
22	Equitization of Intercompany Receivables	
23		
24		
25		
26	Common Stock	
27		
28		
29		
30	Equity Infusion from Duke Energy Corporation	
31		
32		
33		
34	Other Misc Paid-In Capital	
35		
36		
37		
38		
39		
40	TOTAL	3,725,067,453

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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		
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7		
8		
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12		
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16		
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19		
20		
21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	10,236,306,557	103,867,610

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	4,624,809
27			803,000 D
28			
29	Bonds issued through Medium Term Notes Facility:		
30	Accounts 222 and 223:		
31	--		
32	Duke Energy Corporation - 1.664%	300,000,000	
33	TOTAL	10,236,306,557	103,867,610

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	Account 224:		
3	--		
4			
5	Pollution Control Bond 1993 - 3.6%	77,000,000	3,143,212
6			
7			
8	Pollution Control .79% 1999A	25,000,000	250,643
9			
10	Pollution Control .81% 1999B	10,000,000	110,666
11			
12	Pollution Control 2006A - 4.375% fixed	71,605,000	1,393,412
13			
14	Pollution Control 2006B - 4.375% fixed	71,595,000	1,354,512
15			
16	Pollution Control 2008A - 4.625% fixed	50,000,000	1,143,326
17			
18	Pollution Control 2008B - 4.625% fixed	50,000,000	1,264,318
19			
20	Other Long Term Debt	465,112,532	2,876,363
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	10,236,306,557	103,867,610

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	9,647,708	889,400	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	400,000,000	21,000,000	28
						29
						30
01/10/2008	01/15/2038	01/2008	01/2038	500,000,000	30,000,000	31
						32
				10,108,368,369	444,229,502	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	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	300,000,000	15,300,000	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	500,000,000	35,000,000	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	2,656,806	26
						27
						28
						29
						30
						31
10/2008	2099			300,000,000	6,738,726	32
				10,108,368,369	444,229,502	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
						2
						3
						4
11/03/2003	02/01/2017	11/2003	02/2017		231,000	5
						6
						7
10/28/1999	02/01/2017	10/1999	02/2017		23,571	8
						9
10/28/1999	02/01/2017	10/1999	02/2017		9,598	10
						11
09/01/2010	10/01/2031	09/2010	10/2031	71,605,000	3,132,719	12
						13
09/01/2010	10/01/2031	09/2010	10/2031	71,595,000	3,132,281	14
						15
09/01/2010	11/01/2040	09/2010	11/2040	50,000,000	2,312,500	16
						17
09/01/2010	11/01/2040	09/2010	11/2040	50,000,000	2,312,500	18
						19
				455,520,661	13,565,401	20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				10,108,368,369	444,229,502	33

Schedule Page: 256.1 Line No.: 32 Column: a

The interest rate varies on this intercompany loan. The interest rate is as of December 31, 2017.

Schedule Page: 256.2 Line No.: 20 Column: a

The Other Long Term Debt ending balance includes gains on cancelled swaps of $5.5 million as of December 31, 2017. The 2017 amortization of these gains was a credit of ($0.5) million to account number 427.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	1,214,747,120
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	764,521,025
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	450,226,095
28	Show Computation of Tax:	
29		
30	35% of $450,226,095	157,579,133
31	Prior Year Federal Tax Adjustments - Primarily Prior Year Tax True-Ups	62,776,191
32		
33		
34	Total Federal Income Tax	220,355,324
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

Provision for Deferred Income Taxes	(414,304,628)
Provision for Current Federal Income Taxes	(220,355,324)
AFUDC Equity Income	105,820,147
AFUDC Interest	44,925,700
Manufacturing Deduction	53,320,000
Book Depreciation	(979,148,101)
Capitalized Interest for Tax	(62,883,342)
Tax Depreciation	1,486,981,680
Tax Gain/Loss (Cost of Removal)	112,000,000
Nuclear Fuel Book Burned	(307,787,905)
Section 263A Adjustment	51,250,000
Equipment Repairs	194,000,000
Long Term Capital Lease Obligation	(39,304,681)
T&D Repairs	337,000,000
Reg Asset Save-A-Watt Program	87,367,861
Deferred Asset - SC DERP	25,523,116
Deferred Fuel Asset	94,852,125
Renewable Energy Adjustment	(31,360,407)
Self Developed Software	73,380,440
Retirement Plan Funding - Underfunded	45,635,230
Net Operating Loss Utilization/Deferral	39,200,903
Coal Ash Spend, Net of Capitalized Portion	93,637,431
Other Items	(25,229,220)
Total	764,521,025

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 Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	4,857,706		11,289,974	13,256,846	79,920
5	Unemployment	27,452		415,295	433,845	
6	Miscellaneous			233,195	233,195	
7	Income taxes	16,621,617		10,880,834	7,541,013	-3,339,822
8						
9	LOCAL					
10	Property 2017	58,766,446	3,655,446	89,407,547	128,096,522	-386,196
11						
12						
13						
14	SOUTH CAROLINA					
15	STATE					
16	Franchise	1,769,921		8,037,509	6,696,808	
17	Unemployment	6,433		338,848	342,690	
18	Kilowatt hour	639,600		8,910,400	8,896,490	
19	Miscellaneous			1,054	1,054	
20	Income Taxes	15,385,253		9,623,646	6,845,872	-971,642
21						
22	LOCAL					
23	Property 2017	30,908,928		115,620,193	30,636,327	-575,788
24						
25						
26	OTHER STATES					
27	Unemployment	2,084		22,055	23,911	
28						
29	FEDERAL					
30	Social Security	11,639,699		45,665,848	45,665,859	275,594
31	Unemployment	8,303		916,855	920,215	39
32	Highway Use			53,163	53,163	
33	Income taxes	-7,720,799		220,355,324	172,958,209	5,066,693
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	132,912,643	3,655,446	521,771,740	422,602,019	148,798

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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
2,970,754		11,289,974				4
8,902		415,295				5
		233,195				6
16,621,616		10,273,598			607,236	7
						8
						9
19,644,803	3,608,974	86,219,771			3,187,776	10
						11
						12
						13
						14
						15
3,110,622		8,037,509				16
2,591		338,848				17
653,510		8,910,400				18
		782			272	19
17,191,385		9,301,456			322,190	20
						21
						22
115,317,006		115,217,629			402,564	23
						24
						25
						26
228		22,055				27
						28
						29
11,915,282		45,665,848				30
4,982		916,855				31
		53,163				32
44,743,009		212,429,582			7,925,742	33
						34
						35
						36
						37
						38
						39
						40
232,184,690	3,608,974	509,325,960			12,445,780	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 35%. 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 - 7,146,876 excluded from Balance At Beginning Of Year (column b)
Sales and Use Tax Payable - 6,795,164 excluded from Balance At End Of Year (column g)

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

Offset to account 186	$(21,124)
Offset to account 253	101,044
Total	$79,920

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

Offset to account 146

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

Offset to account 143	$494,856
Offset to account 146	331,986
Offset to account 182	(886,323)
Offset to account 253	(41,411)
Offset to account 419	(285,304)
Total	$(386,196)

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

Offset to account 146

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

Offset to account 182	$(45,984)
Offset to account 232	(529,804)
Total	$(575,788)

Schedule Page: 262 Line No.: 27 Column: b

Prior year end of year balances that were reported on multiple rows are being consolidated on one row for reporting going forward.

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

Offset to account 242

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

Offset to account 107

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

Offset to account 410

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	1,603,532			411.4	78,375	
4	7%						
5	10%	66,742,118			411.4	5,219,965	
6	15%	125,000,000					
7	30%	9,240,000	255	35,550,000			-448,900
8	TOTAL	202,585,650		35,550,000		5,298,340	-448,900
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
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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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
1,525,157			3
			4
61,522,153			5
125,000,000			6
44,341,100			7
232,388,410			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

The 10% amounts for electric utility contain ITC that was calculated at 8% of the basis value. This is a result of the Company's election under IRS Code Section 48(q)4 which allows a company to calculate ITC at 10% with a basis reduction or at 8% with no basis reduction.

The amount included in electric utility at 8% is:

Balance at beginning of year	$ 11,009,122
Allocations to current year's income	$ (782,536)
Balance at end of year	$ 10,226,586

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

Eligible ITC for progress expenditures at the Cliffside Plant. Placed in service date 2012. Tax Credit is 15% with $125M cap for the entire project.

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

Estimated eligible 30% ITC for expenditures for the Mocksville Solar project. Placed in service date 2016.

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

Estimated eligible 30% ITC for expenditures for the Monroe Solar project. Placed in service date 2017.

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

The deferral of $9,240,000 reported for 2016 represented an estimate of the 30% ITC for the Mocksville Solar project. During 2017, the 2016 Federal Tax Return was filed and the actual amount of the credit was $8,791,100, which was $448,900 lower than originally estimated.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	391,390,824	0128	7,543,543	67,662,599	451,509,880
3						
4	Prepaid Extra Facilities Lighting	19,921,925	Various	8,049,408	3,471,824	15,344,341
5						
6	Merger Related Charitable	35,700,000	0131	11,900,000		23,800,000
7	Contributions					
8						
9	Deferred Income Tax - NC Rate	88,147,568	Various	18,348,206	13,886,520	83,685,882
10	Change					
11						
12	Catawba - Wateree relicensing	8,098,911	Various	2,167,391	2,572,879	8,504,399
13	future projects and Misc					
14						
15	Manufactured Gas Plants	7,290,000	0131, 0426	611,741	1,477,741	8,156,000
16	Reserve					
17						
18	Other	19,617,438	Various	14,921,436	13,464,665	18,160,667
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	570,166,666		63,541,725	102,536,228	609,161,169

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	6,452,625,233	858,731,082	731,382,099
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	6,452,625,233	858,731,082	731,382,099
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	6,452,625,233	858,731,082	731,382,099
10	Classification of TOTAL			
11	Federal Income Tax	5,955,608,603	859,880,338	747,392,084
12	State Income Tax	497,016,630	-1,149,256	-16,009,985
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
11,807,706	2,235,078	182,253,254	2,465,488,046	254	5,533,132	4,129,591,930	2
							3
							4
11,807,706	2,235,078		2,465,488,046		5,533,132	4,129,591,930	5
							6
							7
							8
11,807,706	2,235,078		2,465,488,046		5,533,132	4,129,591,930	9
							10
11,809,975	3,232,976		2,414,140,276		5,497,022	3,668,030,602	11
-2,269	-997,898		51,347,770		36,110	461,561,328	12
							13

NOTES (Continued)

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

182 - Regulatory Assets	$196,372,757(b)
253 - North Carolina Excess Deferred Income Taxes	8,167,120
254 - North Carolina Excess Deferred Income Taxes	22,990,844
254 - Federal Excess Deferred Income Taxes	2,237,957,325(a)
Total	$2,465,488,046

(a) Estimated remeasurement of existing deferred tax liabilities to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act. Where the reduction in the accumulated deferred tax liability is expected to be returned to customers in future rates, the estimated remeasurement has been deferred as a net regulatory liability.

(b) Includes the impact of the estimated remeasurement of existing deferred taxes to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act.

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

254 - Other Regulatory Liabilities $5,533,132(b)

(b) Includes the impact of the estimated remeasurement of existing deferred taxes to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		2,696,747,781	309,793,781	131,414,721
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	2,696,747,781	309,793,781	131,414,721
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	116,181,382	2,508,426	8,664,479
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	2,812,929,163	312,302,207	140,079,200
20	Classification of TOTAL			
21	Federal Income Tax	2,562,354,641	299,016,195	139,775,323
22	State Income Tax	250,574,522	13,286,012	303,877
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
-146,236	-385,039		1,169,545,889	146	1,564,532	1,707,384,287	3
							4
							5
							6
							7
							8
-146,236	-385,039		1,169,545,889		1,564,532	1,707,384,287	9
							10
							11
							12
							13
							14
							15
							16
							17
196,475	416,929		40,750,228			69,054,647	18
50,239	31,890		1,210,296,117		1,564,532	1,776,438,934	19
							20
47,231	1,053		1,173,186,207		1,365,143	1,549,820,627	21
3,008	30,837		37,109,910		199,389	226,618,307	22
							23

NOTES (Continued)

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

190 - Reclass between 190 and 283	$2,914,227
182 - Regulatory Assets	219,431,359(b)
253 - North Carolina Excess Deferred Income Taxes	3,517,342
254 - North Carolina Excess Deferred Income Taxes	9,901,489
254 - Federal Excess Deferred Income Taxes	933,558,559(a)
254 - Other Regulatory Liabilities	244,176(b)
283 - Reclass between Electric and Other Categories	(21,263)
Total	$1,169,545,889

(a) Estimated remeasurement of existing deferred tax liabilities to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act. Where the reduction in the accumulated deferred tax liability is expected to be returned to customers in future rates, the estimated remeasurement has been deferred as a net regulatory liability.

(b) Includes the impact of the estimated remeasurement of existing deferred taxes to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act.

Schedule Page: 276 Line No.: 18 Column: a

Relates primarily to deferred taxes on regulatory assets for deferred plant costs and nuclear levelization.

Schedule Page: 276 Line No.: 18 Column: h

253 - North Carolina Excess Deferred Income Taxes	$142,180
254 - North Carolina Excess Deferred Income Taxes	400,235
254 - Federal Excess Deferred Income Taxes	40,186,550(a)
283 - Reclass between Electric and Other Categories	21,263
Total	$40,750,228

(a) Estimated remeasurement of existing deferred tax liabilities to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act. Where the reduction in the accumulated deferred tax liability is expected to be returned to customers in future rates, the estimated remeasurement has been deferred as a net regulatory liability.

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	138,679,742	Various	687,362,178	628,349,763	79,667,327
4						
5	NC Tax Rate Change					
6	NCUC Docket No. M-100, Sub 138	248,139,735	Various	374,970,624	362,410,758	235,579,869
7						
8	Settlement give back		Various		14,515,333	14,515,333
9	NCUC Docket No E-7 Sub 1051					
10						
11	ARO Regulatory Liability		Various		344,921,106	344,921,106
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	31,785,968	Various	1,000,000		30,785,968
18						
19	NC REC Liability					
20	NCUC Docket E-7, Sub 1052	44,685,740	407/456	15,381,591	33,106,892	62,411,041
21						
22	SC Storm Reserve Fund					
23	SCPSC Docket 2013-59-E	21,512,245	Various	6,341,415	5,000,000	20,170,830
24						
25	OPEB Liability	41,746,234	Various	10,888,167	13,570,607	44,428,674
26	FERC Docket No. AI07-1-000					
27	FAS 106 - Medical	4,610,680	Various	6,035,556	1,483,282	58,406
28						
29	NDTF Contaminated Liability					
30	NCUC Docket No E-7 Sub 723					
31	SCPSC Docket No 2003-84-E	460,505,258	Various			460,505,258
32						
33	End of Life Reserves					
34	NCUC Docket No. E-7, Sub 1026	59,702,500	Various		18,370,000	78,072,500
35						
36	NDTF Giveback					
37	NCUC Docket No. E-100 Sub 56					
38	PSC Docket No.2015-96-E					
39	NC Long-Term Liab	3,794,857	182/254	3,794,857		
40	SC Long-Term Liab Defer Fuel	(14,147,356)	182/254	2,773,263	16,920,618	-1
41	TOTAL	1,189,911,046		1,460,076,435	4,841,319,292	4,571,153,903

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	79,524,604	182/254	167,462,728	133,662,856	45,724,732
4						
5	Mark to Market Fuel - LT	33,062,162	Various	121,630,886	88,728,303	159,579
6						
7	SC Unbilled Fuel					
8	PSCSC Docket 2014-3-E	36,308,677	182/254	62,435,170	26,126,493	
9						
10	Reg Liab - Excess Fed ADIT		Various		3,154,153,281	3,154,153,281
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,189,911,046		1,460,076,435	4,841,319,292	4,571,153,903

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

Year-end December 2016 balance was reclassified from Other Deferred Credits (account 0253) to Regulatory Liabilities.

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	2,743,777,629	2,996,677,058
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	2,217,977,416	2,299,520,808
5	Large (or Ind.) (See Instr. 4)	1,221,920,876	1,250,045,067
6	(444) Public Street and Highway Lighting	46,404,801	47,453,782
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	6,230,080,722	6,593,696,715
11	(447) Sales for Resale	555,060,872	514,901,476
12	TOTAL Sales of Electricity	6,785,141,594	7,108,598,191
13	(Less) (449.1) Provision for Rate Refunds	13,034,471	9,736,306
14	TOTAL Revenues Net of Prov. for Refunds	6,772,107,123	7,098,861,885
15	Other Operating Revenues		
16	(450) Forfeited Discounts	18,368,585	19,977,986
17	(451) Miscellaneous Service Revenues	10,801,723	13,587,227
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	98,418,196	95,027,749
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	329,455,619	20,285,207
22	(456.1) Revenues from Transmission of Electricity of Others	86,079,787	85,174,639
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	543,123,910	234,052,808
27	TOTAL Electric Operating Revenues	7,315,231,033	7,332,914,693

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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
26,717,072	28,380,458	2,181,646	2,148,432	2
				3
28,493,826	28,995,889	355,583	349,400	4
21,922,218	21,782,414	6,239	6,295	5
302,180	304,148	15,375	15,190	6
				7
				8
				9
77,435,296	79,462,909	2,558,843	2,519,317	10
9,871,268	9,081,806	24	24	11
87,306,564	88,544,715	2,558,867	2,519,341	12
				13
87,306,564	88,544,715	2,558,867	2,519,341	14

Line 12, column (b) includes $ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

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

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	(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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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 Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	14,785,255	1,564,997,383	1,247,965	11,847	0.1058
2	RE - Res. Water Htr. & Space Cond	11,498,641	1,139,154,618	912,958	12,595	0.0991
3	RET - Res Water Htr & Space TOU					
4	RST - Residential Service TOU	1	180	1	1,000	0.1800
5	RB - Res. Service	73,633	8,136,479	5,609	13,128	0.1105
6	RT - Res. Service	52,672	4,570,079	2,204	23,898	0.0868
7	WC - Res. Service Controlled W-H	18,299	1,020,252	10,026	1,825	0.0558
8	ES - Energy Star	164,801	16,428,113	12,909	12,766	0.0997
9	Subtotal - Account 440	26,593,302	2,734,307,104	2,191,672	12,134	0.1028
10	Unbilled Alloc. - Residential	123,770	9,470,525			0.0765
11	Duplicate Customers			-10,026		
12	Total Residential	26,717,072	2,743,777,629	2,181,646	12,246	0.1027
13	G - General Service	3,100	50,124	86	36,047	0.0162
14	GA - General Service					
15	OPT - General Service	2,748,906	180,412,658	4,852	566,551	0.0656
16	OL - Outdoor Lighting	420,823	87,376,096	337,272	1,248	0.2076
17	BC - Bldg - Construction Service	18,139	3,260,504	9,644	1,881	0.1798
18	I - Industrial Service	2,744,901	215,124,242	4,755	577,266	0.0784
19	OPT - Industrial Service	6,865,120	347,323,050	514	13,356,265	0.0506
20	PG - Parallel Generation	5,061	820,969	9	562,333	0.1622
21	FL - Flood Lighting	230,759	32,184,678	6,168	37,412	0.1395
22	SG - (GEN) - Small General Ser		1	2		
23	SGS - Small General Service	5,519,470	622,434,097	313,311	17,617	0.1128
24	LGS - Large General Service	5,899,935	471,844,335	11,390	517,993	0.0800
25	S - UNMETERED STREET LIGHTS					
26	Yard Lighting	-1	93	1	-1,000	-0.0930
27	OPTVG - General Service	12,817,765	776,464,911	16,023	799,960	0.0606
28	OPTVI - Industrial Service	10,119,666	569,452,103	1,126	8,987,270	0.0563
29	Water Heating					
30	HO-Hourly Pricing	2,499,131	107,823,861	33	75,731,242	0.0431
31	MP-Multiple Premises	271,983	14,299,024	62	4,386,823	0.0526
32	MFR-Miscellaneous Non-metered		74,476	15		
33	Subtotal - Account 442	50,164,758	3,428,945,222	705,263	71,129	0.0684
34	Duplicate Customers			-343,441		
35	Unbilled Alloc. - Commercial & In	251,286	10,953,070			0.0436
36	Total Commercial & Industrial	50,416,044	3,439,898,292	361,822	139,339	0.0682
37						
38						
39						
40						
41	TOTAL Billed	77,059,080	6,209,452,176	2,558,843	30,115	0.0806
42	Total Unbilled Rev.(See Instr. 6)	376,216	20,628,546	0	0	0.0548
43	TOTAL	77,435,296	6,230,080,722	2,558,843	30,262	0.0805

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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						
2						
3	PL - Street and Public Lighting	265,071	36,989,010	6,448	41,109	0.1395
4	TS - Traffic Signal - Safety Non	12,597	2,274,362	7,341	1,716	0.1805
5	GL - Governmental Lighting Servic	23,073	6,811,948	1,578	14,622	0.2952
6	NL - Standard Lighting Service	279	124,530	8	34,875	0.4463
7	Subtotal - Account 444	301,020	46,199,850	15,375	19,579	0.1535
8	Unbilled Alloc. - Pub St & Highwa	1,160	204,951			0.1767
9	Total Public Street and Highway	302,180	46,404,801	15,375	19,654	0.1536
10	Total Retail Unbilled Fuel Clause					
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	77,059,080	6,209,452,176	2,558,843	30,115	0.0806
42	Total Unbilled Rev.(See Instr. 6)	376,216	20,628,546	0	0	0.0548
43	TOTAL	77,435,296	6,230,080,722	2,558,843	30,262	0.0805

Schedule Page: 304 Line No.: 5 Column: a

Schedules no longer available for new customers.

Schedule Page: 304 Line No.: 7 Column: d

These customers are also served under other rate schedules.

Schedule Page: 304 Line No.: 12 Column: d

The totals do not include duplications of customers served under more than one rate schedule.

Schedule Page: 304 Line No.: 12 Column: e

The totals do not include duplications of customers served under more than one rate schedule.

Schedule Page: 304 Line No.: 16 Column: d

These customers are also served under other rate schedules.

Schedule Page: 304 Line No.: 21 Column: d

These customers are also served under other rate schedules.

Schedule Page: 304 Line No.: 26 Column: a

Schedules no longer available to new customers.

Schedule Page: 304 Line No.: 36 Column: d

The totals do not include duplications of customers served under more than one rate schedule.

Schedule Page: 304 Line No.: 36 Column: e

The totals do not include duplications of customers served under more than one rate schedule.

Schedule Page: 304.1 Line No.: 10 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).

Schedule Page: 304 Line No.: 41 Column: d

The totals do not include duplications of customers served under more than one rate schedule.

Schedule Page: 304 Line No.: 41 Column: e

The totals do not include duplications of customers served under more than one rate schedule.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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:
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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	246	231
3	Blue Ridge Electric Membership					
4	Corporation	AD	315			
5	Central Electric Power Cooperative,Inc.	RQ	336	582	531	521
6	Central Electric Power Cooperative,Inc.	AD	336			
7	City of Concord	RQ	327	178	173	172
8	City of Concord	AD	327			
9	City of Kings Mountain	RQ	331	22	27	26
10	City of Kings Mountain	AD	331			
11	City of Greenwood, SC	RQ	334	59	57	55
12	City of Greenwood, SC	AD	334			
13	Haywood Electric Membership Corporation	RQ	335	22	25	22
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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

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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	Lockhart Power Company	RQ	332	42	62	61
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	88	87	83
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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

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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	Rutherford Electric Membership					
2	Corporation	RQ	317	215	268	264
3	Rutherford Electric Membership					
4	Corporation	AD	317			
5	Town of Dallas	RQ	328	13	14	13
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	23	22
10	Town of Forest City	AD	330			
11	Town of Highlands	RQ	337	8	9	8
12	Town of Highlands	AD	337			
13	Town of Prosperity	RQ	333	2	2	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

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	(a)	(b)	(c)	(d)	(e)	(f)
1	Western Carolina University	RQ	338	7	9	8
2	Western Carolina University	AD	338			
3	Broad River Energy, LLC	OS	4			
4	Cargill Power Markets, LLC	OS	4			
5	North Carolina Municipal Power Agency 1	OS	4			
6	Piedmont Municipal Power Agency	OS	4			
7	Southern Power Company - Rowan Plant	OS	4			
8	Southern Power Company -Cleveland Plant	OS	4			
9	North Carolina Electric Membership					
10	Corporation	OS	273			
11	Cargill Power Markets, LLC	OS	5			
12	Cargill Power Markets, LLC	OS	6			
13	EDF Trading North America, LLC	OS	5			
14	Exelon Generation Company, LLC	OS	5			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SALES FOR RESALE (Account 447)

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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Midcontinent Independent System					
2	Operator, Inc.	OS	5			
3	Morgan Stanley Capital Group	OS	5			
4	PJM Settlement, Inc.	OS	5			
5	PJM Settlement, Inc.	AD	5			
6	South Carolina Electric & Gas Company	OS	5			
7	South Carolina Electric & Gas Company	OS	294			
8	South Carolina Public Service Authority	OS	293			
9	Southern Company Services, Inc.	OS	5			
10	Tennessee Valley Authority	OS	3			
11	The Energy Authority, Inc.	OS	5			
12	Westar Energy	OS	5			
13	Brookfield Energy Marketing LP	OS	4			
14	Cargill Power Markets, LLC	OS	4			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SALES FOR RESALE (Account 447)

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1	City of Seneca, South Carolina	OS	4			
2	Eagle Energy Partners	OS	4			
3	Energy United Electric Membership					
4	Corporation	OS	4			
5	Exelon Generation Co., LLC	OS	4			
6	Lockhart Power Company	OS	4			
7	Macquarie Energy	OS	4			
8	Morgan Stanley Capital Group Inc.	OS	4			
9	North Carolina Electric Membership					
10	Corporation	OS	4			
11	North Carolina Municipal Power Agency 1	OS	4			
12	Piedmont Municipal Power Agency	OS	4			
13	South Carolina Electric & Gas Company	OS	4			
14	South Carolina Public Service Authority	OS	4			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	Southern Power Company	OS	4			
2	The Energy Authority, Inc.	OS	4			
3	Duke Energy Progress, Inc.	LF	341			
4	Duke Energy Progress, Inc.	AD	341			
5	Duke Energy Progress, Inc.	OS	10			
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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
1,352,828	38,479,821	33,020,784		71,500,605	2
					3
	-186,705	-184,815		-371,520	4
2,846,089	112,369,610	67,267,306		179,636,916	5
6,312	-3,986,845	-127,799		-4,114,644	6
943,694	33,496,476	22,798,663		56,295,139	7
	-129,735	-127,914		-257,649	8
155,086	4,410,845	3,739,791		8,150,636	9
	-14,531	-20,373		-34,904	10
298,773	11,309,023	7,062,998		18,372,021	11
	-43,980	-41,325		-85,305	12
122,789	3,805,085	2,902,737		6,707,822	13
	-22,894	-16,859		-39,753	14
8,052,479	293,753,428	192,931,673	0	486,685,101	
1,818,789	-4,902,691	72,898,253	380,209	68,375,771	
9,871,268	**288,850,737**	**265,829,926**	**380,209**	**555,060,872**	

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SALES FOR RESALE (Account 447) (Continued)

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MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
331,311	7,217,217	7,832,202		15,049,419	1
	-30,413	-42,702		-73,115	2
					3
391,244	12,974,802	9,249,024		22,223,826	4
	-279,553	-52,178		-331,731	5
					6
7,631	1,050,000	309,370		1,359,370	7
	1,814			1,814	8
					9
390,686	14,339,888	9,235,853		23,575,741	10
					11
	-73,955	-54,310		-128,265	12
53,373	8,290,094	1,261,747		9,551,841	13
	-102,636	-5,014		-107,650	14
8,052,479	293,753,428	192,931,673	0	486,685,101	
1,818,789	-4,902,691	72,898,253	380,209	68,375,771	
9,871,268	**288,850,737**	**265,829,926**	**380,209**	**555,060,872**	

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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
860,157	36,833,397	21,130,986		57,964,383	2
					3
	-183,747	-120,366		-304,113	4
72,237	2,347,076	1,758,433		4,105,509	5
	-839,285	-9,850		-849,135	6
12,490	388,115	295,286		683,401	7
	-1,626	-1,757		-3,383	8
118,626	3,703,283	2,878,577		6,581,860	9
	-15,593	-16,337		-31,930	10
48,387	1,653,100	1,203,912		2,857,012	11
	-20,123	-6,624		-26,747	12
11,054	349,588	261,307		610,895	13
	-1,968	-1,440		-3,408	14
8,052,479	293,753,428	192,931,673	0	486,685,101	
1,818,789	-4,902,691	72,898,253	380,209	68,375,771	
9,871,268	**288,850,737**	**265,829,926**	**380,209**	**555,060,872**	

SALES FOR RESALE (Account 447) (Continued)

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43,655	1,786,008	1,032,067		2,818,075	1
	-20,916	-5,971		-26,887	2
1,668			146,952	146,952	3
1,396			4,988	4,988	4
1,871			3,450	3,450	5
1,183			325	325	6
3,785			195,682	195,682	7
3,125			52,398	52,398	8
					9
153,827		19,336,379		19,336,379	10
21,753		969,103		969,103	11
371		6,680		6,680	12
91		4,530		4,530	13
275		11,490		11,490	14
8,052,479	293,753,428	192,931,673	0	486,685,101	
1,818,789	-4,902,691	72,898,253	380,209	68,375,771	
9,871,268	**288,850,737**	**265,829,926**	**380,209**	**555,060,872**	

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					1
50		10,438		10,438	2
840		40,145		40,145	3
24,732		1,189,350		1,189,350	4
		-16,530		-16,530	5
20,450		1,137,075		1,137,075	6
2,534		94,051		94,051	7
6,935		376,770		376,770	8
1,800		84,200		84,200	9
7,150		364,050		364,050	10
18,327		1,028,918		1,028,918	11
2,827		178,931		178,931	12
			-1,278	-1,278	13
			-2,103	-2,103	14
8,052,479	293,753,428	192,931,673	0	486,685,101	
1,818,789	-4,902,691	72,898,253	380,209	68,375,771	
9,871,268	**288,850,737**	**265,829,926**	**380,209**	**555,060,872**	

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			-186	-186	1
			-59	-59	2
					3
			-760	-760	4
			-1,551	-1,551	5
			-3	-3	6
140			-93	-93	7
			-54	-54	8
					9
			-5,115	-5,115	10
			-6,739	-6,739	11
			-2,091	-2,091	12
			-8	-8	13
			-1,135	-1,135	14
8,052,479	293,753,428	192,931,673	0	486,685,101	
1,818,789	-4,902,691	72,898,253	380,209	68,375,771	
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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.
			-2,322	-2,322	1
			-89	-89	2
1,527,800		48,644,492		48,644,492	3
1,733		-49,145		-49,145	4
183		13,590		13,590	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
8,052,479	293,753,428	192,931,673	0	486,685,101	
1,818,789	-4,902,691	72,898,253	380,209	68,375,771	
9,871,268	**288,850,737**	**265,829,926**	**380,209**	**555,060,872**	

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: 310.3 Line No.: 8 Column: j
Represents Generation imbalance 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.: 4 Column: j
Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 5 Column: j
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Schedule Page: 310.5 Line No.: 6 Column: j
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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.: 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: j

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

Schedule Page: 310.6 Line No.: 2 Column: j

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

Schedule Page: 310.6 Line No.: 3 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.: 4 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.: 5 Column: i

Represents intercompany sales pursuant to the VACAR agreement

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	14,817,549	17,295,745
5	(501) Fuel	864,621,618	861,230,298
6	(502) Steam Expenses	54,242,002	54,304,824
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.	-65	
9	(505) Electric Expenses	7,400,350	7,521,429
10	(506) Miscellaneous Steam Power Expenses	18,183,387	22,704,887
11	(507) Rents		
12	(509) Allowances	13,640,526	13,560,969
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	972,905,497	976,618,152
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	13,394,902	14,106,983
16	(511) Maintenance of Structures	5,486,862	11,634,673
17	(512) Maintenance of Boiler Plant	43,658,585	47,947,972
18	(513) Maintenance of Electric Plant	29,813,044	28,673,443
19	(514) Maintenance of Miscellaneous Steam Plant	6,657,814	4,359,705
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	99,011,207	106,722,776
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,071,916,704	1,083,340,928
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	36,307,644	42,426,059
25	(518) Fuel	308,365,109	294,289,658
26	(519) Coolants and Water	8,884,540	9,412,855
27	(520) Steam Expenses	49,123,796	54,191,543
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	21,303,114	21,403,012
31	(524) Miscellaneous Nuclear Power Expenses	182,739,652	195,974,619
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	606,723,855	617,697,746
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	73,266,249	80,760,772
36	(529) Maintenance of Structures	12,537,039	15,462,151
37	(530) Maintenance of Reactor Plant Equipment	86,762,995	100,785,997
38	(531) Maintenance of Electric Plant	57,836,639	68,365,994
39	(532) Maintenance of Miscellaneous Nuclear Plant	45,930,851	46,920,650
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	276,333,773	312,295,564
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	883,057,628	929,993,310
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	7,652,327	7,775,296
45	(536) Water for Power		
46	(537) Hydraulic Expenses	-830,335	-393,973
47	(538) Electric Expenses	5,613,211	4,981,931
48	(539) Miscellaneous Hydraulic Power Generation Expenses	8,951,738	8,459,044
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	21,386,941	20,822,298
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	2,614,689	2,646,565
54	(542) Maintenance of Structures	1,270,898	2,360,326
55	(543) Maintenance of Reservoirs, Dams, and Waterways	3,553,530	3,913,813
56	(544) Maintenance of Electric Plant	6,721,117	7,055,932
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,941,237	4,489,779
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	18,101,471	20,466,415
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	39,488,412	41,288,713

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	5,341,868	5,773,267
63	(547) Fuel	299,835,877	306,632,815
64	(548) Generation Expenses	1,653,542	1,799,411
65	(549) Miscellaneous Other Power Generation Expenses	10,651,187	8,867,308
66	(550) Rents	-33,910	-92,924
67	TOTAL Operation (Enter Total of lines 62 thru 66)	317,448,564	322,979,877
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	3,451,402	2,309,143
70	(552) Maintenance of Structures	7,142,474	7,254,035
71	(553) Maintenance of Generating and Electric Plant	7,437,884	8,001,357
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	5,419,576	5,300,975
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	23,451,336	22,865,510
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	340,899,900	345,845,387
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	348,770,283	333,120,270
77	(556) System Control and Load Dispatching	7,922	83,913
78	(557) Other Expenses	198,416,760	157,170,300
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	547,194,965	490,374,483
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,882,557,609	2,890,842,821
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	10,256	-7,346
84			
85	(561.1) Load Dispatch-Reliability	1,245,799	1,044,569
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	8,471,596	9,694,695
87	(561.3) Load Dispatch-Transmission Service and Scheduling	811,724	788,004
88	(561.4) Scheduling, System Control and Dispatch Services	1,614	2,992
89	(561.5) Reliability, Planning and Standards Development	231,610	237,219
90	(561.6) Transmission Service Studies	22,370	5,831
91	(561.7) Generation Interconnection Studies	-37,269	118,737
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,692,699	2,323,295
94	(563) Overhead Lines Expenses	1,068,110	952,854
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	2,637,455	4,530,988
97	(566) Miscellaneous Transmission Expenses	10,875,479	8,179,748
98	(567) Rents	68,458	132,588
99	TOTAL Operation (Enter Total of lines 83 thru 98)	27,099,901	28,004,174
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		7,607
102	(569) Maintenance of Structures	152,022	160,432
103	(569.1) Maintenance of Computer Hardware	221,392	143,687
104	(569.2) Maintenance of Computer Software	2,129,308	2,935,589
105	(569.3) Maintenance of Communication Equipment	23,389	38,060
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	7,865,412	7,971,145
108	(571) Maintenance of Overhead Lines	15,857,393	18,032,818
109	(572) Maintenance of Underground Lines	10,622	-3,315
110	(573) Maintenance of Miscellaneous Transmission Plant	14,870	26,539
111	TOTAL Maintenance (Total of lines 101 thru 110)	26,274,408	29,312,562
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	53,374,309	57,316,736

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	667,947	982,737
135	(581) Load Dispatching	7,315,735	8,618,763
136	(582) Station Expenses	1,711,226	1,995,917
137	(583) Overhead Line Expenses	3,269,939	2,686,618
138	(584) Underground Line Expenses	11,119,860	10,949,320
139	(585) Street Lighting and Signal System Expenses	1,168,723	1,029,885
140	(586) Meter Expenses	16,022,534	9,439,732
141	(587) Customer Installations Expenses	7,449,234	11,063,689
142	(588) Miscellaneous Expenses	45,397,509	43,050,259
143	(589) Rents	252,043	170,934
144	TOTAL Operation (Enter Total of lines 134 thru 143)	94,374,750	89,987,854
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	272,276	239,167
147	(591) Maintenance of Structures		463
148	(592) Maintenance of Station Equipment	3,701,202	3,937,870
149	(593) Maintenance of Overhead Lines	152,481,665	156,188,739
150	(594) Maintenance of Underground Lines	8,920,262	5,298,182
151	(595) Maintenance of Line Transformers	1,866,435	2,082,975
152	(596) Maintenance of Street Lighting and Signal Systems	5,111,083	4,066,976
153	(597) Maintenance of Meters	2,549,231	2,513,820
154	(598) Maintenance of Miscellaneous Distribution Plant	6,912,040	6,443,881
155	TOTAL Maintenance (Total of lines 146 thru 154)	181,814,194	180,772,073
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	276,188,944	270,759,927
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	396,348	383,643
160	(902) Meter Reading Expenses	3,650,664	3,840,527
161	(903) Customer Records and Collection Expenses	68,063,002	66,250,226
162	(904) Uncollectible Accounts	11,758,924	12,554,370
163	(905) Miscellaneous Customer Accounts Expenses	367,337	477,636
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	84,236,275	83,506,402

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	320	1,925
169	(909) Informational and Instructional Expenses	105,180	193,698
170	(910) Miscellaneous Customer Service and Informational Expenses	20,614,998	20,414,171
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	20,720,498	20,609,794
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	267	
175	(912) Demonstrating and Selling Expenses	10,789,667	9,509,762
176	(913) Advertising Expenses	793,089	844,907
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	11,583,023	10,354,669
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	123,190,385	178,166,476
182	(921) Office Supplies and Expenses	80,674,709	74,651,424
183	(Less) (922) Administrative Expenses Transferred-Credit	40,066,555	45,576,833
184	(923) Outside Services Employed	75,094,166	68,015,112
185	(924) Property Insurance	10,862,755	19,725,087
186	(925) Injuries and Damages	27,990,183	46,034,933
187	(926) Employee Pensions and Benefits	130,547,563	141,456,621
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	11,375,477	12,084,698
190	(929) (Less) Duplicate Charges-Cr.	31,140,037	26,136,284
191	(930.1) General Advertising Expenses	5,439,844	3,532,922
192	(930.2) Miscellaneous General Expenses	-29,328,249	-34,884,222
193	(931) Rents	47,215,358	51,520,771
194	TOTAL Operation (Enter Total of lines 181 thru 193)	411,855,599	488,590,705
195	Maintenance		
196	(935) Maintenance of General Plant	2,287,672	2,504,832
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	414,143,271	491,095,537
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,742,803,929	3,824,485,886

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 $91,942,445.

Schedule Page: 320 Line No.: 12 Column: b

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 $591,816.

Also includes $11,387,785 that represents the amount 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.: 197 Column: b

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

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	ACTIVE CONCEPTS LLC	LU	(1)			
3	AKS REAL ESTATE HOLDINGS LLC	LU	(1)			
4	ALAMANCE HYDRO, LLC	LU	(1)			
5	ALL-STATES MEDICAL SUPPLY INC.	LU	(1)			
6	AMETHYST SOLAR , LLC	LU	(1)			
7	ANDREWS TRUSS,INC	LU	(1)			
8	ANGEL SOLAR , LLC	LU	(1)			
9	APPLE DATA CENTER PV2	IU	(1)			
10	APPLE FUEL CELL FACILITY	LU	(1)			
11	APPLE FUEL CELL FACILITY	AD	(1)			
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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	APPLE PV1	AD	(1)			
3	Aquenergy - Piedmont Hydro	LU	(1)			
4	Aquenergy - Ware Shoals Hydro	LU	(1)			
5	ARARAT ROCK SOLAR, LLC	LU	(1)			
6	ARCADIA COMMUNITY SOLAR, LLC	LU	(1)			
7	ARNDT FARM LLC	LU	(1)			
8	ASHLEY SOLAR	LU	(1)			
9	AUDREY SOLAR , LLC	LU	(1)			
10	AVALON HYDROPOWER, LLC	LU	(1)			
11	BANK OF AMERICA	LU	(1)			
12	Barbara Ann Evans	LU	(1)			
13	BARRY BINGHAM	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	BARRY R WHARTON	LU	(1)			
2	BATTLEGROUND SOLAR I, LLC	LU	(1)			
3	BEETLE SOLAR, LLC	LU	(1)			
4	BELWOOD FARM, LLC	LU	(1)			
5	BENJAMIN R. EUSTICE	LU	(1)			
6	BERNHARDT FURNITURE COMPANY	LU	(1)			
7	BETH SOLAR LLC	LU	(1)			
8	BETTY HAYGOOD	LU	(1)			
9	BG STEWART SOLAR FARM, LLC	LU	(1)			
10	BIG BOY SOLAR,LLC	LU	(1)			
11	BIOMERIEUX, INC	LU	(1)			
12	BLACK HAWK INC	LU	(1)			
13	BLUE BRIGHT VENTURES, 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

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OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BLUM, INC.	LU	(1)			
2	BOYD LEON HYDER	LU	(1)			
3	BRANCH,JAMES DAVID DR	LU	(1)			
4	BRIAN M ATTIS	LU	(1)			
5	BRYAN C TURNER	LU	(1)			
6	BUDDY SOLAR, LLC	LU	(1)			
7	BURLINGTON HYDRO LLC	LU	(1)			
8	Byron P Matthews	LU	(1)			
9	C2 Solar	IU	(1)			
10	CAROL JEAN SOLAR,LLC	LU	(1)			
11	CARRBORO COMMUNITY SOLAR LLC	LU	(1)			
12	Catawba County - Blackburn Landfill	LU	(1)			
13	CATAWBA GREEN STEP SOLAR, 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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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	CATAWBA SOLAR, LLC	LU	(1)			
2	CATAWBA SOLAR, LLC	AD	(1)			
3	CATHERINE C HOOKS	LU	(1)			
4	CHAD COLLINS	LU	(1)			
5	CHAPEL HILL TIRE CO	LU	(1)			
6	CHAPEL HILL TIRE COMPANY, INC.	LU	(1)			
7	CHARLES BRANDON MITCHELL	LU	(1)			
8	CHARLES BRECKHEIMER	LU	(1)			
9	CHARLIE SOLAR, LLC	LU	(1)			
10	CHARLOTTE SOLAR, LLC	LU	(1)			
11	CHEROKEE FALLS HYDRO	LU	(1)			
12	CHEROKEE FALLS HYDRO	AD	(1)			
13	CHRISTOPHER D HARDIN	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

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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	CISCO SYSTEMS INC	IU	(1)			
2	CITY OF CHARLOTTE	LU	(1)			
3	CITY VIEW COMMERCIAL LLC	LU	(1)			
4	CLARK H MIZELL	LU	(1)			
5	CLEAN ENERGY,LLC	LU	(1)			
6	Cliffside Mills LLC	LU	(1)			
7	CLINE SOLAR, LLC	LU	(1)			
8	CLOVER SCHOOL DISTRICT 2	LU	(1)			
9	COC SURRY LFG,LLC	LU	(1)			
10	COMMONWEALTH BRANDS INC	LU	(1)			
11	CONCEPTS BY GARY	LU	(1)			
12	CONCORD ENERGY LLC	LU	(1)			
13	CONGOLINA SOLAR, 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Converse Energy - Clifton Dam #3 Hydro	LU	(1)			
2	Converse Energy - Clifton Dam #3 Hydro	AD	(1)			
3	COUNTY HOME SOLAR CENTER LLC	LU	(1)			
4	COUNTY HOME SOLAR CENTER LLC	AD	(1)			
5	CT WILSON PROPERTIES, LLC	LU	(1)			
6	DANIEL E SUMAN	LU	(1)			
7	DANIEL FARM, LLC	LU	(1)			
8	DANIELLE SEAMAN	LU	(1)			
9	DAVID BOYER	LU	(1)			
10	DAVID H NEWMAN	LU	(1)			
11	DAVID W WALTERS	LU	(1)			
12	DAVID ZIMMER	LU	(1)			
13	DAVIDSON GAS PRODUCERS, 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	DDM MORTGAGE CORPORATION	LU	(1)			
2	DECISION SUPPORT	LU	(1)			
3	DEE INDUSTRIES	LU	(1)			
4	DELTA PRODUCTS CORP.	LU	(1)			
5	DIANE E JAMES	LU	(1)			
6	DIBRELL FARM, LLC	LU	(1)			
7	DIRK J SPRUYT	LU	(1)			
8	DIXON DAIRY ROAD, LLC	LU	(1)			
9	DOMENICO SANTILLI	LU	(1)			
10	DON A BICKNELL	LU	(1)			
11	DOUGLAS ALBRIGHT THOMPSON	LU	(1)			
12	DRAGSTRIP FARM	LU	(1)			
13	DURHAM LANDFILL ELECTRICITY 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	DURHAM SOLAR , LLC	LU	(1)			
2	EARNHARDT-CHILDRESS RACING	LU	(1)			
3	TECHNOLOGIES,LLC					
4	ELLIANA SOLAR, LLC	LU	(1)			
5	ELON COMMUNITY SOLAR, LLC	LU	(1)			
6	ELSEWHERE LIVING MUSEUM	LU	(1)			
7	ERIC L GAYLORD	LU	(1)			
8	ESTES EXPRESS LINES, INC	LU	(1)			
9	FACILE SOLAR, LLC	LU	(1)			
10	FISHER SOLAR FARM, LLC	LU	(1)			
11	FLASH SOLAR , LLC	LU	(1)			
12	FLS OWNER II, LLC	LU	(1)			
13	FOOTHILLS WINEWORX 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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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	FREEMONT SOLAR CENTER, LLC	LU	(1)			
2	Freightliner Corp	LU	(1)			
3	FREIRICH FOODS, LLC	LU	(1)			
4	FRESH AIR ENERGY XV, LLC	LU	(1)			
5	FRESH AIR ENERGY XXIX, LLC	LU	(1)			
6	GAIL SEVERS SCHNEITLER	LU	(1)			
7	GAS RECOVERY SYSTEMS, LLC	LU	(1)			
8	GASTON COUNTY	LU	(1)			
9	GENERAL ELECTRIC COMPANY	LU	(1)			
10	GERALD W. MEISNER	LU	(1)			
11	GERMANTOWN SOLAR, LLC	LU	(1)			
12	GOOD SOLAR ELECTRIC, LLC	IU	(1)			
13	GREENSBORO PLUMBING SUPPLY 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	GREENVILLE COUNTY SCHOOLS	LU	(1)			
2	GREENVILLE GAS PRODUCERS, LLC	LU	(1)			
3	GWENYTH T REID	LU	(1)			
4	Haneline Power, LLC	LU	(1)			
5	HAROLD FERGUSON	LU	(1)			
6	Haw River Hydro Co - Saxapahaw Hydro	LU	(1)			
7	HAYNES FARM, LLC	LU	(1)			
8	HMS Holdings Limited Partnership	LU	(1)			
9	HOFFMAN & HOFFMAN	LU	(1)			
10	HOWELL MIDLAND FARM, LLC	LU	(1)			
11	HUSKY SOLAR LLC	LU	(1)			
12	HUTCHINSON FARM,LLC	LU	(1)			
13	INDUSTRIAL CENTERS, LLC	LU	(1)			
14						
	Total					

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	INNOVATIVE SOLAR 14, LLC	LU	(1)			
2	INNOVATIVE SOLAR 15, LLC	LU	(1)			
3	INNOVATIVE SOLAR 16, LLC	LU	(1)			
4	INNOVATIVE SOLAR 18, LLC	LU	(1)			
5	INNOVATIVE SOLAR 23, LLC	LU	(1)			
6	INNOVATIVE SOLAR 26, LLC	LU	(1)			
7	IRVINE RIVER COMPANY	LU	(1)			
8	ITRON INC	LU	(1)			
9	JACOB SOLAR LLC	LU	(1)			
10	Jafasa Farms Greenhouse	LU	(1)			
11	Jafasa Farms Residence	LU	(1)			
12	JAMES EDWARD ROWELL JR	LU	(1)			
13	JAMES J BOYLE	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.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	JARROD W BARTRON	LU	(1)			
2	JEFFERY LYNN PARDUE	LU	(1)			
3	JIM AND LINDA ALEXANDER	LU	(1)			
4	JOHN B ROBBINS	LU	(1)			
5	JOHN H. DILIBERTI	LU	(1)			
6	JUBA ALUMINUM PRODUCTS	LU	(1)			
7	COMPANY INC					
8	KAREN STURGIS	LU	(1)			
9	KENNETH A BOLLEN	LU	(1)			
10	KEVIN NEWELL	LU	(1)			
11	KMBA, LLC	LU	(1)			
12	LAFAYETTE SOLAR I, LLC	LU	(1)			
13	LAMAR BAILES	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	LARRY STENGER	LU	(1)			
2	LAURA J BALLANCE	LU	(1)			
3	LAWRENCE ELECTRIC	LU	(1)			
4	LEON'S BEAUTY SCHOOL, INC	LU	(1)			
5	LINCOLN SOLAR LLC	LU	(1)			
6	LOCKHART - LOWER PACOLET HYDRO	LU	(1)			
7	LOCKHART - UPPER PACOLET HYDRO	LU	(1)			
8	LOCKHART BIOENERGY, LLC	LU	(1)			
9	LOCKHART BIOENERGY, LLC	AD	(1)			
10	LOCKHART Minimum Flow	LU	(1)			
11	LOCKHART Minimum Flow	AD	(1)			
12	LOCKHART POWER COMPANY	LU	(1)			
13	LOTUS SOLAR 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	LUX SOLAR I LLC	LU	(1)			
2	LUX SOLAR I LLC	AD	(1)			
3	LYNWOOD SOLAR I LLC	LU	(1)			
4	MARIPOSA SOLAR CENTER LLC	LU	(1)			
5	MARK S TRUSTIN	LU	(1)			
6	MARKET FARM, LLC	LU	(1)			
7	MARSHVILLE FARM ,LLC	LU	(1)			
8	MARTIN JOSEPH LASHUA	LU	(1)			
9	MARTIN TRUEX JR. LLC	LU	(1)			
10	MATTHEW C ROBERTS	LU	(1)			
11	MATTHEW T. EWERS	LU	(1)			
12	MAYBERRY SOLAR LLC	LU	(1)			
13	Mayo Hydropower LLC - Mayo Hydro	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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.

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1	MEADOWBROOK SOLAR, LLC	LU	(1)			
2	MEADOWBROOK SOLAR, LLC	AD	(1)			
3	MEHUL SHAH	LU	(1)			
4	MIDTOWN SHOPS, LLC	LU	(1)			
5	Mill Shoals Hydro - High Shoals Hydro	LU	(1)			
6	MILL SOLAR I LLC	LU	(1)			
7	MILLIKAN FARM, LLC	LU	(1)			
8	MILO SOLAR, LLC	LU	(1)			
9	MINNESOTA MINING & MFG CO	LU	(1)			
10	MINNIE SOLAR , LLC	LU	(1)			
11	MISENHEIMER FARM, LLC	LU	(1)			
12	MOCKSVILLE FARM,LLC	LU	(1)			
13	MONROE MOORE 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	MOORE SOLAR FARM,LLC	LU	(1)			
2	NARENCO	LU	(1)			
3	NATHANIEL J POOVEY	LU	(1)			
4	NC SOLAR DOCKS LLC	LU	(1)			
5	NEISLER STREET SOLAR I LLC	LU	(1)			
6	Net metering for SC DERP	LU	(1)			
7	NEWTON-CONOVER CITY SCHOOLS	LU	(1)			
8	NICK SOLAR,LLC	LU	(1)			
9	Northbrook Carolina - Boyds Mill Hydro	IU	(1)			
10	Northbrook Carolina - Holliday's	IU	(1)			
11	Bridge Hydro					
12	Northbrook Carolina - Saluda Hydro	IU	(1)			
13	Northbrook Carolina - Turner Shoals	IU	(1)			
14	Hydro					
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NYPRO,INC	LU	(1)			
2	OAKDALE HOLDING LLC	LU	(1)			
3	OENOPHILIA	LU	(1)			
4	OLD DOMINION FREIGHT LINE INC	LU	(1)			
5	OLD PAGELAND-MONROE ROAD SOLAR	LU	(1)			
6	ORBIT ENERGY CHARLOTTE,LLC	LU	(1)			
7	ORBIT ENERGY CHARLOTTE,LLC	AD	(1)			
8	OWEN SOLAR , LLC	LU	(1)			
9	PAUL M NEUBAUER	LU	(1)			
10	Pelzer Hydro Co - Lower Pelzer Hydro	LU	(1)			
11	Pelzer Hydro Co - Upper Pelzer Hydro	LU	(1)			
12	PHARR YARNS LLC	IU	(1)			
13	PHILIP E MINER	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	Pickins Mill Hydro LLC	IU	(1)			
2	PIERRE BURKE	LU	(1)			
3	PRS-PK ENGINES,LLC	LU	(1)			
4	PUBLIC LIBRARY OF CHARLOTTE	LU	(1)			
5	R B SOLAR LLC	LU	(1)			
6	R B SOLAR LLC	AD	(1)			
7	R LAWRENCE ASHE JR	LU	(1)			
8	RAINER DAMMERS	LU	(1)			
9	RAJAH Y CHACKO	LU	(1)			
10	RAJENDRA MOREY	LU	(1)			
11	RAMONA L SHERWOOD	LU	(1)			
12	RAYLEN VINEYARDS INC	LU	(1)			
13	REBECCA A DURANTE	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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	REBECCA G LASKODY	LU	(1)			
2	REBECCA T COBEY	LU	(1)			
3	REDMON SOLAR FARM, LLC	LU	(1)			
4	REI 2 LLC	LU	(1)			
5	ROBERT SKIRBOLL	LU	(1)			
6	ROBERT W STONE	LU	(1)			
7	ROCKWELL SOLAR, LLC	LU	(1)			
8	RONNIE B POWERS	LU	(1)			
9	ROPER FARM, LLC	LU	(1)			
10	ROUSCH & YATES RACING ENGINES, LLC	LU	(1)			
11	RUNAWAY PROPERTIES LLC	LU	(1)			
12	RUSSELL VON STEIN	LU	(1)			
13	RUTHERFORD FARM, LLC	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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SAIA MOTOR FREIGHT LINE, LLC	LU	(1)			
2	SALEM ENERGY SYSTEMS, LLC	LU	(1)			
3	SANDAN FARM	LU	(1)			
4	SHELBY RANDOLPH ROAD SOLAR I , LLC	LU	(1)			
5	SHELDON R PINNELL	LU	(1)			
6	SHOE SHOW, INC	LU	(1)			
7	SID SOLAR I, LLC	LU	(1)			
8	SIGMON CATAWBA FARM,LLC	LU	(1)			
9	SONNE TWO,LLC	LU	(1)			
10	SOPHIE SOLAR, LLC	LU	(1)			
11	SOUTH WINSTON FARM, LLC	LU	(1)			
12	South Yadkin Power, Inc.	LU	(1)			
13	SOUTHDATA 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SPARTANBURG WATER SYSTEM	LU	(1)			
2	SPENCER FARM, LLC	LU	(1)			
3	SPENCER MOUNTAIN HYDROPOWER, LLC	LU	(1)			
4	SPENCER YOST	LU	(1)			
5	STANLEY CHAMBERLAIN	LU	(1)			
6	Star Solar, LLC	LU	(1)			
7	Steve Mason Ent., Inc. - Long Shoals	LU	(1)			
8	Hydro					
9	STIKELEATHER FARM, LLC	LU	(1)			
10	STONEVILLE SOLAR LLC	LU	(1)			
11	STOUT FARM LLC	LU	(1)			
12	SUMMIT SHOPPING CENTER COMPANY	LU	(1)			
13	SUN CAPITAL,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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

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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	SUN EDISON LLC	LU	(1)			
2	SUN LIGHT 1 LLC	LU	(1)			
3	SUSAN E REYNOLDS	LU	(1)			
4	T.S. DESIGNS, INC.	LU	(1)			
5	TEMPLE EMANUEL	LU	(1)			
6	TENCARVA MACHINERY COMPANY	LU	(1)			
7	TerraForm LLC; DBA: SunE B9	LU	(1)			
8	Holdings, LLC					
9	TerraForm LLC; DBA: SunE B9	AD	(1)			
10	Holdings, LLC					
11	THE CITY OF CHARLOTTE	LU	(1)			
12	THE MEASURED DOSE PHARMACY INC.	LU	(1)			
13	THE NORTHWESTERN MUTUAL LIFE	LU	(1)			
14	INSURANCE					
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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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	THE ROCKET SHOP, LLC	LU	(1)			
2	THE ROPER GROUP, LLC	IU	(1)			
3	THOMAS SCHOPLER	LU	(1)			
4	THOMAS W BATES	LU	(1)			
5	TIBURON HOLDINGS LLC	LU	(1)			
6	TIMBERLYNE LEGION, LLC	LU	(1)			
7	TONY M SMITH	LU	(1)			
8	Town of Chapel Hill	LU	(1)			
9	Town Of Lake Lure - Lake Lure Hydro	LU	(1)			
10	TRINITY POWER NC, LLC	LU	(1)			
11	TRIPPLE STATE FARM, LLC	LU	(1)			
12	TRIPPLE STATE FARM, LLC	AD	(1)			
13	TROPICAL NUT & FRUIT 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	TWC ADMINISTRATION LLC	LU	(1)			
2	TWC ADMINISTRATION LLC	AD	(1)			
3	TWO LINES FARM, LLC	LU	(1)			
4	UNC - CHAPEL HILL	LU	(1)			
5	UNIFI MANUFACTURING, INC	LU	(1)			
6	UNITED SEWING MACHINE SALES, LLC	LU	(1)			
7	UNITED THERAPEUTICS CORPORATION	LU	(1)			
8	URBAN MINISTRIES OF DURHAM	LU	(1)			
9	VETRORESINA LLC	LU	(1)			
10	VIDYA SAGAR SETHI	LU	(1)			
11	VOLT SOLAR, LLC	LU	(1)			
12	W B MOORE CO OF CHAR	LU	(1)			
13	WACO 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	WALLACE & GRAHAM PA	LU	(1)			
2	WALTER C. MCGERVEY	LU	(1)			
3	WALTER O BRADLEY	LU	(1)			
4	WANDA J WILLIAMS	LU	(1)			
5	WATAUGA COUNTY	LU	(1)			
6	WEST SALISBURY FARM, LLC	LU	(1)			
7	WHITE CROSS FARM, LLC	LU	(1)			
8	WHITE CROSS SOLAR LLC	LU	(1)			
9	WHITE CROSS SOLAR LLC	AD	(1)			
10	WHITE OAK OF SALUDA, LLC	LU	(1)			
11	WILKES COUNTY	LU	(1)			
12	WILLIAM D MOORE	LU	(1)			
13	WILLIAM P MILLER	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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.

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OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	WM RENEWABLE ENERGY,LLC	LU	(1)			
2	WM3 PROPERTIES	LU	(1)			
3	WRIGHT OF THOMASVILLE INC	LU	(1)			
4	YADKIN 601 FARM,LLC	LU	(1)			
5	YADKINVILLE SOLAR, LLC	LU	(1)			
6	YORK ROAD SOLAR I , LLC	LU	(1)			
7	YUZE HOLDINGS LLC	IU	(1)			
8	YVES NAAR	LU	(1)			
9	Southeastern Power Administration	OS	124			
10	Residential Solar Credit	OS				
11	North Carolina Municipal Power Agency	EX	271			
12	North Carolina Electric Member	EX	273			
13	Corporation					
14	Small Customer Generator Credits	OS				
	Total					

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Piedmont Municipal Power Agency	EX	314			
2	North Carolina Municipal Power Agency	OS	271			
3	North Carolina Electric Member	OS	273			
4	Corporation					
5	Piedmont Municipal Power Agency	OS	313			
6	Blue Ridge Electric Membership	RQ	315			
7	Corporation					
8	Cargill Power Markets, LLC	OS	(2)			
9	Cherokee County Cogeneration	OS	(2)			
10	Partners, LLC					
11	City of Concord, North Carolina	RQ	327			
12	City of Kings Mountain, North Carolina	RQ	331			
13	DE Progress	OS	341			
14	DE Progress	AD	341			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	EDF Trading North America, LLC	OS	(2)			
2	Exelon Generation Company, LLC	OS	(2)			
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	RQ	326			
8	NC Electric Member Corporation	OS	(2)			
9	North Carolina Municipal Power Agency	RQ	318			
10	Number 1					
11	North Carolina Municipal Power Agency	OS	(2)			
12	Number 1					
13	Piedmont Electric Membership	RQ	316			
14	Corporation					
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Piedmont Municipal Power Agency	RQ	340			
2	PJM Settlements, Inc	OS	(2)			
3	PJM Settlements, Inc	AD	(2)			
4	South Carolina Electric & Gas Company	AD	(2)			
5	South Carolina Electric & Gas Company	OS	(2)			
6	Transmission					
7	Southern Company Services, Inc.	OS	(2)			
8	Southern Company Services, Inc.	AD	(2)			
9	Tennessee Valley Authority	OS	(2)			
10	Tennessee Valley Authority	OS	(2)			
11	Transmission					
12	The Energy Authority	OS	(2)			
13	Town of Dallas, North Carolina	RQ	328			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Town of Forest City, North Carolina	RQ	330			
2	Broad River Energy Center c/o Calpine	EX	(3)			
3	Corp					
4	Cargill-Alliant, LLC	EX	(3)			
5	Macquarie Energy LLC	EX	(3)			
6	NCMPA	EX	(3)			
7	Piedmont Municipal Power Agency	EX	(3)			
8	Southern Power Company - Cleveland	EX	(3)			
9	Plant					
10	Southern Power Company - Rowan Plant	EX	(3)			
11	City of Seneca	EX	(4)			
12	EnergyUnited Electric Memb	EX	(4)			
13	NC Electric Membership Corpor	EX	(4)			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	NCMPA	EX	(4)			
2	Piedmont Municipal Power Agenc	EX	(4)			
3	SCE&G COMPANY	EX	(4)			
4	South Carolina Public Service	EX	(4)			
5	Authority - p2p					
6	Brookfield Energy Marketing LP	OS	Ferc 890			
7	Cargill-Alliant, LLC	OS	Ferc 890			
8	Eagle Energy Partners	OS	Ferc 890			
9	Exelon Power Team	OS	Ferc 890			
10	Lockhart Power Company	OS	Ferc 890			
11	Macquarie Energy LLC	OS	Ferc 890			
12	Morgan Stanley Capital Group Inc	OS	Ferc 890			
13	Rainbow Energy Marketing	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	South Carolina Public Service	OS	Ferc 890			
2	Authority - p2p					
3	Southern Wholesale	OS	Ferc 890			
4	The Energy Authority	OS	Ferc 890			
5	Westar Energy	OS	Ferc 890			
6	Operating Regulating	EX	(5)			
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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)	
1,071				71,432		71,432	1
101				5,161		5,161	2
3				166		166	3
452				28,257		28,257	4
73				3,233		3,233	5
5,868				392,517		392,517	6
				3		3	7
9,353				622,568		622,568	8
39,600				2,335,668		2,335,668	9
77,631				4,449,394		4,449,394	10
				111,397		111,397	11
36,444				2,154,424		2,154,424	12
9,880				658,549		658,549	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	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.
39,731				2,849,531		2,849,531	1
				82,201		82,201	2
4,096				225,058		225,058	3
4,243				230,724		230,724	4
5,888				447,009		447,009	5
				10		10	6
9,019				690,916		690,916	7
7,007				463,387		463,387	8
5,107				340,502		340,502	9
3,673				260,257		260,257	10
10				688		688	11
315				16,659		16,659	12
1				51		51	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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				158		158	1
5,906				386,949		386,949	2
6,221				417,739		417,739	3
7,409				563,595		563,595	4
4				220		220	5
1,771				117,320		117,320	6
8,696				571,621		571,621	7
3				132		132	8
9,912				697,652		697,652	9
5,166				342,852		342,852	10
143				7,244		7,244	11
5				230		230	12
129				8,582		8,582	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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.
2,424				156,932		156,932	1
13				641		641	2
12				576		576	3
2				80		80	4
8				331		331	5
6,724				448,647		448,647	6
681				48,926		48,926	7
				7		7	8
26				1,511		1,511	9
6,496				421,495		421,495	10
6				302		302	11
17,770				764,092		764,092	12
867				56,585		56,585	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,680				182,267		182,267	1
302				17,028		17,028	2
				6		6	3
				4		4	4
21				1,068		1,068	5
5				232		232	6
				10		10	7
				6		6	8
7,587				442,964		442,964	9
9,388				624,670		624,670	10
8,030				432,524		432,524	11
1				49		49	12
2				81		81	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
117				5,886		5,886	1
2,632				129,897		129,897	2
6				311		311	3
4				188		188	4
13,137				562,645		562,645	5
1,265				62,940		62,940	6
3,227				238,909		238,909	7
48				2,727		2,727	8
6,392				448,704		448,704	9
225				11,303		11,303	10
6				309		309	11
65,844				4,582,742		4,582,742	12
1,248				82,009		82,009	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,746				150,991		150,991	1
				1,208		1,208	2
3,781				252,619		252,619	3
56				5,560		5,560	4
48				3,055		3,055	5
1				37		37	6
9,225				613,176		613,176	7
6				352		352	8
4				158		158	9
2				83		83	10
4				204		204	11
				5		5	12
13,202				918,991		918,991	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
107				5,470		5,470	1
39				1,959		1,959	2
7				339		339	3
33				1,665		1,665	4
6				341		341	5
9,337				717,597		717,597	6
5				236		236	7
6,982				534,882		534,882	8
6				256		256	9
5				258		258	10
				7		7	11
9,027				603,714		603,714	12
15,407				893,769		893,769	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
6,262				415,302		415,302	1
91				3,673		3,673	2
							3
9,635				687,179		687,179	4
3				118		118	5
6				298		298	6
1				43		43	7
898				60,620		60,620	8
3,630				240,126		240,126	9
9,703				643,086		643,086	10
8,563				567,031		567,031	11
5				257		257	12
36				1,826		1,826	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

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.
9,247				619,719		619,719	1
1				17		17	2
104				4,963		4,963	3
6,029				404,914		404,914	4
5,553				370,912		370,912	5
9				459		459	6
28,034				1,877,244		1,877,244	7
29,786				1,861,650		1,861,650	8
1,369				92,524		92,524	9
6				290		290	10
2,942				206,968		206,968	11
8				398		398	12
76				3,831		3,831	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
34				1,872		1,872	1
15,008				727,807		727,807	2
4				210		210	3
402				28,101		28,101	4
6				287		287	5
4,200				307,278		307,278	6
8,411				644,024		644,024	7
70				2,802		2,802	8
147				7,366		7,366	9
9,413				626,839		626,839	10
8,541				570,788		570,788	11
10,157				682,320		682,320	12
98				6,304		6,304	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	
3,596				275,611		275,611	1
3,351				257,580		257,580	2
3,105				207,411		207,411	3
3,663				243,564		243,564	4
3,884				259,077		259,077	5
3,655				242,161		242,161	6
3,428				246,412		246,412	7
80				4,066		4,066	8
9,252				651,934		651,934	9
5				230		230	10
9				439		439	11
1				55		55	12
5				243		243	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
11				506		506	1
5				237		237	2
1				47		47	3
10				419		419	4
10				473		473	5
13				641		641	6
							7
3				172		172	8
1				26		26	9
4				223		223	10
13				657		657	11
3,513				236,753		236,753	12
6				307		307	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
27				1,329		1,329	1
8				347		347	2
3				126		126	3
44				2,202		2,202	4
9,286				599,319		599,319	5
3,534				247,036		247,036	6
4,137				289,156		289,156	7
18,740				1,011,965		1,011,965	8
3				142		142	9
4,682				327,298		327,298	10
				30		30	11
11,496				738,024		738,024	12
7,537				501,463		501,463	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,012				270,473		270,473	1
64				3,380		3,380	2
190				9,679		9,679	3
9,638				639,806		639,806	4
3				143		143	5
8,923				597,132		597,132	6
8,442				646,267		646,267	7
1				29		29	8
76				3,858		3,858	9
7				327		327	10
				10		10	11
1,492				112,283		112,283	12
3,030				219,719		219,719	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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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)	
9,864				658,771		658,771	1
25				1,423		1,423	2
3				111		111	3
75				5,029		5,029	4
2,812				196,003		196,003	5
1,607				108,951		108,951	6
10,034				666,844		666,844	7
5,963				394,667		394,667	8
7				542		542	9
5,816				384,205		384,205	10
9,451				629,837		629,837	11
9,101				694,925		694,925	12
9,540				635,713		635,713	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,771				672,350		672,350	1
935				46,410		46,410	2
3				145		145	3
12				787		787	4
3,183				215,977		215,977	5
544				26,265		26,265	6
178				9,037		9,037	7
9,122				698,913		698,913	8
2,693				135,174		135,174	9
8,528				425,914		425,914	10
							11
4,529				224,837		224,837	12
11,360				564,385		564,385	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

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)	
225				11,211		11,211	1
26				1,302		1,302	2
24				1,194		1,194	3
2,125				108,030		108,030	4
10,206				717,834		717,834	5
2,867				177,603		177,603	6
29				1,838		1,838	7
9,691				646,751		646,751	8
4				183		183	9
5,972				324,673		324,673	10
4,685				255,911		255,911	11
3				90		90	12
7				367		367	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
944				45,458		45,458	1
12				590		590	2
4				174		174	3
28				1,333		1,333	4
7,017				451,265		451,265	5
722				42,982		42,982	6
6				282		282	7
2				99		99	8
3				140		140	9
5				217		217	10
5				272		272	11
558				37,064		37,064	12
				7		7	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4				206		206	1
				9		9	2
4,018				265,752		265,752	3
8,816				380,313		380,313	4
3				138		138	5
1				52		52	6
6,100				404,807		404,807	7
481				22,520		22,520	8
9,993				666,969		666,969	9
149				5,962		5,962	10
11				570		570	11
2				85		85	12
135,200				8,365,662		8,365,662	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
372				25,024		25,024	1
27,273				1,502,910		1,502,910	2
31				1,551		1,551	3
3,658				246,140		246,140	4
3				121		121	5
5,708				290,817		290,817	6
8,861				597,770		597,770	7
9,162				609,211		609,211	8
9,718				650,230		650,230	9
8,179				544,511		544,511	10
9,490				674,036		674,036	11
775				56,229		56,229	12
12				613		613	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,184				71,055		71,055	1
7,790				533,682		533,682	2
952				56,865		56,865	3
3				144		144	4
9				453		453	5
9,682				643,856		643,856	6
1,686				119,393		119,393	7
							8
9,266				613,857		613,857	9
13				650		650	10
9,038				592,667		592,667	11
21				1,293		1,293	12
27				1,335		1,335	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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.
11,684				792,170		792,170	1
180				9,094		9,094	2
12				583		583	3
12				594		594	4
6				312		312	5
183				9,089		9,089	6
15,983				1,083,667		1,083,667	7
							8
				5,682		5,682	9
							10
400				27,019		27,019	11
6				316		316	12
5				264		264	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2				104		104	1
67				3,621		3,621	2
7				363		363	3
1				33		33	4
9,052				607,548		607,548	5
9				425		425	6
4				227		227	7
4				225		225	8
5,224				342,291		342,291	9
3				205		205	10
10,187				658,093		658,093	11
1,469				84,462		84,462	12
28				1,395		1,395	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
1,305				86,261		86,261	1
102				6,471		6,471	2
8,809				680,328		680,328	3
7,054				380,221		380,221	4
1,419				95,282		95,282	5
377				24,241		24,241	6
5,240				331,390		331,390	7
4				214		214	8
384				30,324		30,324	9
5				271		271	10
1,379				88,666		88,666	11
32				1,650		1,650	12
9,155				705,813		705,813	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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.

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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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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)	
137				6,966		6,966	1
1				64		64	2
7				339		339	3
1				41		41	4
139				6,050		6,050	5
8,913				608,495		608,495	6
8,755				659,719		659,719	7
3,886				257,529		257,529	8
507				28,846		28,846	9
1				37		37	10
10				475		475	11
6				314		314	12
3				147		147	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
14,669				958,566		958,566	1
5				255		255	2
99				5,024		5,024	3
5,580				370,380		370,380	4
6,642				438,831		438,831	5
3,736				248,124		248,124	6
34				1,930		1,930	7
3				166		166	8
				114,047		114,047	9
				16,460		16,460	10
	3,698,216	3,415,441	-733,805	4,929,958		4,196,153	11
69,445	3,032,931	2,801,023	-601,799	3,315,836		2,714,037	12
							13
				2,796		2,796	14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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.

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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	1,232,739	1,138,483	-244,603	442,406		197,803	1
-2,450		2,450		-52,358		-52,358	2
-2,010		2,010		-42,939		-42,939	3
							4
-817		817		-17,453		-17,453	5
291,577			8,002,177	7,440,208		15,442,385	6
							7
123,724				4,806,976		4,806,976	8
622,523			10,480,820	21,433,078		31,913,898	9
							10
734			9,309	32,953		42,262	11
			107,748			107,748	12
5,313,446				145,066,188		145,066,188	13
1,792				51,573		51,573	14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	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.
1,264				27,967		27,967	1
10,035				235,300		235,300	2
78,408			2,033,680	1,981,162		4,014,842	3
							4
45,008				1,704,036		1,704,036	5
2,160				49,260		49,260	6
			53,296			53,296	7
2,820				181,750		181,750	8
467,732				13,097,418		13,097,418	9
							10
1,175				27,525		27,525	11
							12
140,160			3,780,046	3,601,093		7,381,139	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
243,200				6,630,992		6,630,992	1
528,908				14,230,292		14,230,292	2
				-6,263		-6,263	3
				850		850	4
				44,926		44,926	5
							6
40,519				531,440		531,440	7
-184				-1,840		-1,840	8
9,910				325,730		325,730	9
				19,968		19,968	10
							11
2,683				71,480		71,480	12
			7,008			7,008	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
			238,272			238,272	1
1,444				47,354		47,354	2
							3
1,780				16,551		16,551	4
351				7,766		7,766	5
6,223				300,147		300,147	6
1,918				22,867		22,867	7
7,074				165,042		165,042	8
							9
34,570				983,908		983,908	10
	49			1,892		1,892	11
	884			26,494		26,494	12
	529			19,769		19,769	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
	8,432			448,033		448,033	1
	1,308			30,234		30,234	2
	125			4,058		4,058	3
	30,318			935,095		935,095	4
							5
				396		396	6
				548		548	7
				7		7	8
				508		508	9
				17		17	10
				40		40	11
				117		117	12
				3		3	13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				88		88	1
							2
				730		730	3
				63		63	4
				12		12	5
	103,423	102,623					6
							7
							8
							9
							10
							11
							12
							13
							14
9,478,719	8,108,954	7,462,847	23,132,149	325,638,134		348,770,283	

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 Carolina Utilities Commission and the South Carolina Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326.27 Line No.: 8 Column: c

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

Schedule Page: 326.30 Line No.: 2 Column: c

(3) Settlement for imbalance exchange.

Schedule Page: 326.30 Line No.: 11 Column: c

(4)Settlement for imbalance exchange.

Schedule Page: 326.32 Line No.: 6 Column: c

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

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Brookfield Energy Marketing LP	Various	Various	LFP
2	Brookfield Energy Marketing LP	Various	Various	LFP
3	Brookfield Energy Marketing LP	Various	Various	SFP
4	Brookfield Energy Marketing LP	Various	Various	OS
5	Calpine Power Services Company	Various	Various	OS
6	Cargill-Alliant LLC	Various	Various	OS
7	Cargill-Alliant LLC	Various	Various	SFP
8	Carolina Power & Light	Various	Various	LFP
9	Carolina Power & Light	Various	Various	LFP
10	Carolina Power & Light	Various	Various	LFP
11	Carolina Power & Light	Various	Various	LFP
12	Carolina Power & Light	Various	Various	LFP
13	Carolina Power & Light	Various	Various	OS
14	Carolina Power & Light	Various	Various	SFP
15	EDF Trading North America	Various	Various	OS
16	EDF Trading North America	Various	Various	SFP
17	Endure Energy LLC	Various	Various	OS
18	Exelon Power Team	Various	Various	OS
19	Exelon Power Team	Various	Various	SFP
20	FPLEMT (Regulated Marketing Arm of FP&L)	Various	Various	OS
21	Florida Power Corp	Various	Various	OS
22	J.P. Morgan Ventures Energy Corporation	Various	Various	OS
23	Macquarie Energy LLC	Various	Various	OS
24	Macquarie Energy LLC	Various	Various	SFP
25	Mercuria Energy America Inc.	Various	Various	OS
26	Morgan Stanley Capital Group Inc	Various	Various	OS
27	Morgan Stanley Capital Group Inc	Various	Various	SFP
28	NC Electric Membership Corporation	Various	Various	LFP
29	NC Electric Membership Corporation	Various	Various	LFP
30	NC Electric Membership Corporation	Various	Various	LFP
31	NC Electric Membership Corporation	Various	Various	LFP
32	NC Electric Membership Corporation	Various	Various	OS
33	NC Electric Membership Corporation	Various	Various	SFP
34	NCMPA	Various	Various	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	NCMPA	Various	Various	SFP
2	Rainbow Energy Marketing	Various	Various	OS
3	Rainbow Energy Marketing	Various	Various	SFP
4	South Carolina Public Service Authority - P2P	Various	Various	LFP
5	South Carolina Public Service Authority - P2P	Various	Various	LFP
6	South Carolina Public Service Authority - P2P	Various	Various	OS
7	Southern Wholesale	Various	Various	LFP
8	Southern Wholesale	Various	Various	OS
9	Southern Wholesale	Various	Various	SFP
10	Tenaska Power Services Co.	Various	Various	OS
11	The Energy Authority	Various	Various	OS
12	The Energy Authority	Various	Various	SFP
13	Westar Energy	Various	Various	OS
14	Westar Energy	Various	Various	SFP
15	Point to Point MWH(s) for all entries above			
16	Blue Ridge Electric Membership Corporation	Various	Various	FNO
17	Central Electric Power Coop	Various	Various	FNO
18	City of Concord	Various	Various	FNO
19	City of Kings Mountain	Various	Various	FNO
20	City of Seneca	Various	Various	FNO
21	EnergyUnited Electric Membership	Various	Various	FNO
22	Greenwood Commissioners of Public Works	Various	Various	FNO
23	Haywood Electric Membership Corporation	Various	Various	FNO
24	Lockhart	Various	Various	FNO
25	NC Electric Membership Corporation	Various	Various	FNO
26	NCMPA	Various	Various	FNO
27	Piedmont Electric Membership Corporation	Various	Various	FNO
28	Piedmont Municipal Power Agency	Various	Various	FNO
29	Rutherford Electric Membership Corporation	Various	Various	FNO
30	SCE&G COMPANY	Various	Various	FNO
31	SCPSA - Network	Various	Various	FNO
32	Southern Power Rowan	Various	Various	FNO
33	Dallas	Various	Various	FNO
34	Due West	Various	Various	FNO
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	Forest City	Various	Various	FNO
2	Town of Highlands	Various	Various	FNO
3	Prosperity	Various	Various	FNO
4	US Dept of Energy	Various	Various	FNO
5	Western Carolina Energy LLC	Various	Various	FNO
6	Revenue Accrual	Various	Various	
7				
8				
9				
10				
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12				
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33				
34				
	TOTAL			

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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.
454	Various	Various	99			1
454	Various	Various	200			2
443	Various	Various				3
444	Various	Various				4
45	Various	Various				5
119	Various	Various				6
187	Various	Various				7
390	Various	Various	100			8
401	Various	Various	850			9
382	Various	Various	150			10
470	Various	Various	150			11
405	Various	Various	300			12
35	Various	Various				13
163	Various	Various				14
319	Various	Various				15
318	Various	Various				16
412	Various	Various				17
195	Various	Various				18
194	Various	Various				19
149	Various	Various				20
292	Various	Various				21
415	Various	Various				22
486	Various	Various				23
485	Various	Various				24
476	Various	Various				25
19	Various	Various				26
308	Various	Various				27
389D	Various	Various	50			28
474	Various	Various	100			29
472	Various	Various	50			30
471	Various	Various	55			31
334	Various	Various				32
387	Various	Various				33
134	Various	Various				34
			2,336	**34,597,442**	**34,494,721**	

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.
152	Various	Various				1
4	Various	Various				2
341	Various	Various				3
33	Various	Various	10			4
33	Various	Various	22			5
33	Various	Various				6
473	Various	Various	200			7
12	Various	Various				8
161	Various	Various				9
60	Various	Various				10
48	Various	Various				11
306	Various	Various				12
279	Various	Various				13
278	Various	Various				14
				13,152,480	13,049,999	15
	Various	Various		1,350,321	1,350,321	16
	Various	Various		2,828,250	2,828,250	17
	Various	Various		945,967	945,967	18
	Various	Various		156,432	156,432	19
	Various	Various		154,422	154,422	20
	Various	Various		2,678,428	2,678,428	21
	Various	Various		315,977	315,977	22
	Various	Various		122,612	122,612	23
	Various	Various		274,827	274,827	24
	Various	Various		2,066,504	2,066,504	25
	Various	Various		5,295,123	5,295,123	26
	Various	Various		390,127	390,127	27
	Various	Various		2,347,063	2,347,063	28
	Various	Various		1,277,123	1,277,123	29
	Various	Various		4,903	4,903	30
	Various	Various		916,956	916,956	31
	Various	Various				32
	Various	Various		72,597	72,597	33
	Various	Various		12,659	12,659	34
			2,336	**34,597,442**	**34,494,721**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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		119,854	119,854	1
	Various	Various		48,317	48,317	2
	Various	Various		12,000	12,000	3
	Various	Various		10,902	10,662	4
	Various	Various		43,598	43,598	5
	Various	Various				6
						7
						8
						9
						10
						11
						12
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						31
						32
						33
						34
			2,336	**34,597,442**	**34,494,721**	

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.
1,923,075	2,371		1,925,446	1
3,885,000	305		3,885,305	2
		-119,439	-119,439	3
-287,770		80,984	-206,786	4
-280	1,937	5,409	7,066	5
-1,728	43,815	679,229	721,316	6
	99,368	2,232,586	2,331,954	7
				8
				9
				10
				11
				12
-10,060	82	-6,709	-16,687	13
				14
-12,552		249,502	236,950	15
		7,353	7,353	16
-994		1,370	376	17
-147,225		278,736	131,511	18
		1,583,804	1,583,804	19
-2,272		4,646	2,374	20
-3,465		75,227	71,762	21
-18			-18	22
-201,927	21,474	59,363	-121,090	23
	115,580	373,368	488,948	24
-816			-816	25
-65,743		710,329	644,586	26
		57,765	57,765	27
971,250			971,250	28
				29
				30
				31
-64,246		165,127	100,881	32
		48,746	48,746	33
-194,780		1,062,180	867,400	34
63,497,802	**284,932**	**22,297,053**	**86,079,787**	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		901,847	901,847	1
		9,601	9,601	2
		3,758	3,758	3
194,250			194,250	4
				5
-10,271			-10,271	6
1,535,735		-10,925	1,524,810	7
-365,328		2,791,129	2,425,801	8
		1,274,083	1,274,083	9
-23			-23	10
-39,624		553,801	514,177	11
		60,170	60,170	12
-2,481		35,840	33,359	13
		2,426	2,426	14
				15
3,133,718		941,170	4,074,888	16
7,175,053		2,118,924	9,293,977	17
2,229,278		667,515	2,896,793	18
316,138		94,521	410,659	19
401,594		65,234	466,828	20
7,503,123		1,193,242	8,696,365	21
748,450		224,607	973,057	22
298,606		89,659	388,265	23
827,118		248,423	1,075,541	24
5,971,089		-3,618	5,967,471	25
11,127,899		966,205	12,094,104	26
1,126,712		336,673	1,463,385	27
5,787,643		659,674	6,447,317	28
3,590,175		1,077,269	4,667,444	29
15,441		4,251	19,692	30
2,954,589		495,524	3,450,113	31
		-450,579	-450,579	32
165,134		49,351	214,485	33
33,084		9,092	42,176	34
63,497,802	**284,932**	**22,297,053**	**86,079,787**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
256,417		76,895	333,312	1
109,275		32,796	142,071	2
29,276		7,004	36,280	3
399,399		114,045	513,444	4
109,947		32,954	142,901	5
2,090,937		74,916	2,165,853	6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
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				29
				30
				31
				32
				33
				34
63,497,802	**284,932**	**22,297,053**	**86,079,787**	

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.: 2 Column: l
Energy charges include loss compensation.

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

Schedule Page: 328 Line No.: 5 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.: 5 Column: l
Energy charges include loss compensation.

Schedule Page: 328 Line No.: 5 Column: m
Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 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 Line No.: 6 Column: l
Energy charges include loss compensation.

Schedule Page: 328 Line No.: 6 Column: m
Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328 Line No.: 7 Column: l
Energy charges include loss compensation.

Schedule Page: 328 Line No.: 7 Column: m
Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

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 12/31/17.

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 6/30/18.

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: h

This long term firm transaction with Carolina Power & Light expires 12/31/19.

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: h

This long term firm transaction with Carolina Power & Light expires 12/31/20.

Schedule Page: 328 Line No.: 12 Column: a

Carolina Power & Light is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 12 Column: h

This long term firm transaction with Carolina Power & Light expires 12/31/34.

Schedule Page: 328 Line No.: 13 Column: a

Carolina Power & Light is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 13 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.: 13 Column: l

Energy charges include loss compensation.

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: a

Carolina Power & Light is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 15 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.: 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: 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.: 17 Column: m

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

Schedule Page: 328 Line No.: 18 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.: 18 Column: m

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

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: 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.: 20 Column: m

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

Schedule Page: 328 Line No.: 21 Column: a

Florida Power Corp is an affiliate of Duke Energy Carolinas, LLC.

Schedule Page: 328 Line No.: 21 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.: 21 Column: m

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

Schedule Page: 328 Line No.: 22 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.: 23 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.: 23 Column: l

Energy charges include loss compensation.

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: l

Energy charges include loss compensation.

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: 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: 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: m

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

Schedule Page: 328 Line No.: 27 Column: m

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

Schedule Page: 328 Line No.: 28 Column: h

This long term firm transaction with NC Electric Membership Corporation expires 9/30/19.

Schedule Page: 328 Line No.: 28 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.: 29 Column: h

This long term firm transaction with NC Electric Membership Corporation expires 12/31/20.

Schedule Page: 328 Line No.: 30 Column: h

This long term firm transaction with NC Electric Membership Corporation expires 12/31/21.

Schedule Page: 328 Line No.: 31 Column: h

This long term firm transaction with NC Electric Membership Corporation expires 12/31/21.

Schedule Page: 328 Line No.: 32 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.: 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: 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.: 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: 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: h

This long term firm transaction with SC Public Service Authority expires 12/31/18.

Schedule Page: 328.1 Line No.: 4 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.: 5 Column: h

This long term firm transaction with SC Public Service Authority expires 12/31/21.

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 Southern Wholesale expires 5/31/17.

Schedule Page: 328.1 Line No.: 7 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: m

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

Schedule Page: 328.1 Line No.: 8 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.: 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: 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.: 11 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.: 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: 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.: 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: m
Other charges include base transmission and ancillary service charges (scheduling/dispatch and reactive support).

Schedule Page: 328.1 Line No.: 16 Column: k
Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 17 Column: k
Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 18 Column: k
Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 19 Column: k
Reflects transmission provided to Network customers under the Duke Energy Carolinas, LLC Open Access Transmission Tariff.

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.: 29 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.: 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.: 3 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: n

FERC Audit 1Q17 74,916
2016 OATT Settlement Accrual Reversal 4Q17 4,190,939
2017 OATT Settlement Accrual Adjustment 4Q17 -2,100,000
Rounding 4Q17 -2

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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					
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25					
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28					
29					
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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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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			28,801			28,801
2	NCEMC	OS			44,338			44,338
3	Energy United	OS			110,281			110,281
4	Carolina Power & Light	NF				2,275,427	13,074	2,288,501
5	Carolina Power & Light	SFP				152,186	11,614	163,800
6	Tennesse Valley Authort	NF				1,734		1,734
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL				183,420	2,429,347	24,688	2,637,455

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,153,958
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,553,172
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	75,395
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	-37,225,133
6	Dues and Subscriptions to various organizations:	
7	Agribusiness Henderson County	500
8	Alamance County CoC	1,000
9	Alliance for Transportation Electrification	10,000
10	American Society of Corporate Executives	2,938
11	Anderson Area CoC	2,306
12	Artisphere	1,000
13	Asheboro Randolph CoC	1,000
14	Better Business Bureau of Central North Carolina	955
15	Better Business Bureau of Northwest North Carolina	800
16	Cabarrus Regional CoC	2,000
17	Caldwell County CoC	2,045
18	Catawba County CoC	5,000
19	CEB Corporate Leadership Council	24,387
20	Chapel Hill Carrboro CoC	3,300
21	Charlotte CoC	50,000
22	Charlotte Community Affairs Professionals	3,000
23	Cherokee County CoC (NC)	500
24	Chester County CoC	1,250
25	Coal Utilization Research Council	21,066
26	Downtown Winston-Salem Partnership	500
27	E4 Carolinas	7,022
28	Eden CoC	835
29	Energy Corporate Board of Advisors	17,555
30	European American CoC	5,000
31	Franklin Area CoC	500
32	Gaston Regional CoC	1,452
33	Greater Durham CoC	9,300
34	Greater Easley CoC	850
35	Greater Greer CoC	1,090
36	Greater Mauldin CoC	500
37	Greater Oconee CoC	750
38	Greater Raleigh CoC	48,000
39	Greater Statesville CoC	1,384
40	Greater York CoC	520
41	Greensboro CoC	16,014
42	Greenville CoC	21,475
43	Greenwood CoC	986
44	Guardians of the Green Business Sponsorship	1,000
45	Henderson County CoC	1,138
46	TOTAL	-29,328,249

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Henderson County Partners for Economic Progress	1,200
7	Hickory Nut Gorge CoC	500
8	High Point CoC	3,500
9	Hillsborough/Orange County CoC	2,640
10	Hispanic Chamber of the United States	3,511
11	Industrial Asset Management Council	576
12	Jackson CoC	500
13	Keystone Policy Center	5,267
14	King CoC	575
15	Lake Norman CoC	1,200
16	Lake Wylie CoC	920
17	Lancaster County Economic Development Corp	2,300
18	Laurens County Development Corp	10,000
19	Lenoir-Rhyne University Business Council	1,500
20	Lincolnton-Lincoln County CoC	672
21	Manufacturers Association of Florida	1,053
22	McDowell CoC	660
23	Montcross Area CoC	1,580
24	Mooresville-South Iredell CoC	541
25	Mount Airy CoC	1,010
26	Municipal Association of South Carolina	1,250
27	Nature Conservancy	8,778
28	North Carolina Business Committee for Education	3,300
29	North Carolina Museum of Life & Science	1,214
30	North Carolina Zoo Society	3,000
31	Palmetto Business Council	2,125
32	Reidsville CoC	585
33	Ripon Society	9,085
34	Rotary Club of Greenwood	535
35	Rutherford CoC	750
36	Simpsonville Area CoC	660
37	Smoky Mountain Host of NC	1,000
38	South Carolina Association of Counties	1,750
39	South Carolina CoC	12,400
40	South Carolina Manufacturers Alliance	2,920
41	Spartanburg Area CoC	7,727
42	Spartanburg County Municipal Association	500
43	Union County CoC	1,470
44	Upstate Employers Network	1,818
45	U. S. Nuclear Infrastructure Council	2,107
46	TOTAL	-29,328,249

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	VisitGreenvilleSC	1,250
7	Wilkes CoC	1,828
8	Winston-Salem CoC	11,465
9	World 50 Inc	20,035
10	York County Regional CoC	3,400
11	York Rotary Club	640
12	Chamber of Commerce (14)	4,325
13	Miscellaneous	3,841
14		
15	Transferred Employee Homes	1,870,121
16		
17	Leased Circuit Charges	6,054
18		
19	Director's Fees and Expenses	1,819,803
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
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44		
45		
46	TOTAL	-29,328,249

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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			52,622,957		52,622,957
2	Steam Production Plant	266,090,728				266,090,728
3	Nuclear Production Plant	224,364,025				224,364,025
4	Hydraulic Production Plant-Conventional	18,229,686				18,229,686
5	Hydraulic Production Plant-Pumped Storage	20,642,769				20,642,769
6	Other Production Plant	76,626,728				76,626,728
7	Transmission Plant	73,707,356				73,707,356
8	Distribution Plant	245,873,664				245,873,664
9	Regional Transmission and Market Operation					
10	General Plant	58,834,371		127,339		58,961,710
11	Common Plant-Electric					
12	TOTAL	984,369,327		52,750,296		1,037,119,623

B. Basis for Amortization Charges

Limited term electric depreciable plant base is $403,505,386, 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	Steam:						
13	Land Rights	2,022					
14	Other	6,663,927					
15	Subtotal:	6,665,949					
16							
17	Nuclear						
18	Land Rights	957					
19	Other	8,333,757					
20	Subtotal:	8,334,714					
21							
22	Hydro:						
23	Land Rights	23,590					
24	Other	2,106,881					
25	Subtotal:	2,130,471					
26							
27	Other Production:						
28	CT's	2,353,292					
29	Solar	177,358					
30	Subtotal:	2,530,650					
31							
32	Transmission:						
33	Land Rights	162,659					
34	Other	3,660,740					
35	Subtotal:	3,823,399					
36							
37	Distribution:						
38	Land Rights	9,376					
39	Other	11,282,035					
40	Subtotal:	11,291,411					
41							
42	General:						
43	EDP	83,042					
44	Other	934,540					
45	Subtotal:	1,017,582					
46	Total	35,794,176					
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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	North Carolina Utilities Commission:				
2	NCUC Regulatory Fee - Electric	6,607,320		6,607,320	
3	Coal Ash Management Commission Fee per NC				
4	Senate Bill 729				
5	Docket E-7, Sub 989		247,000	247,000	995,666
6	Docket E-7, Sub 1029		210,000	210,000	896,372
7	Docket M-100, Sub 142		-1,003,730	-1,003,730	1,620,363
8					
9					
10	Public Service Commission of South Carolina:				
11	SC PSC Fees	2,488,226		2,488,226	
12	Docket 2009-226-E		10,133	10,133	180,904
13	Docket 2011-271-E		15,945	15,945	387,153
14	Docket 2003-59-E		5,000	5,000	663,331
15	Docket 2015-362-E				
16					
17					
18	Federal Energy Regulatory Commission:				
19	Annual FERC Billing	2,795,583		2,795,583	
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	11,891,129	-515,652	11,375,477	4,743,789

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
Electric	928	6,607,320					2
							3
Electric	928						4
Electric	182				247,000	748,666	5
Electric	182				210,000	686,372	6
Electric	928	-1,003,730	1,003,730			2,624,093	7
							8
							9
							10
Electric	928	2,488,226					11
Electric	182				10,133	170,771	12
Electric	182				15,945	371,208	13
Electric	186				5,000	658,331	14
Electric	928						15
							16
							17
							18
		2,795,583					19
							20
							21
							22
							23
							24
							25
							26
							27
							28
							29
							30
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							43
							44
							45
		10,887,399	1,003,730		488,078	5,259,441	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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) Distribution:	Research & Development Administration Costs
3		
4		
5	(6) Other:	Others (less than $50K each)
6		
7	(7) Total Cost Incurred	
8		
9		
10	B. Electric R,D & D Performed Externally:	
11	(1) Research Support to:	
12	Electric Power Research Institute	Electric Power Research Institute Memberships
13		EPRI Nuclear Co-Funds
14		EPRI DNP Support
15		Others (less than $50K each)
16	(4) Research Support to Others	
17		Alternative Energy (Advanced Energy Resc.)
18		Centre for Energy Advancement through Technological Innovation
19		Clemson University
20		Georgia Tech Research Corporation
21		University of North Carolina
22		
23		
24		
25	(5) Total Cost Incurred	
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
133,468		930.7	133,468		2
					3
					4
					5
					6
133,468			133,468		7
					8
					9
					10
					11
	7,455,753	Various	7,455,753		12
	1,560,331	Various	1,560,331		13
	104,455	524	104,455		14
	23,398	Various	23,398		15
					16
	1,997,959	930.8	1,997,959		17
	99,500	930.7	99,500		18
	80,000	930.7	80,000		19
	160,000	930.7	160,000		20
	82,245	930.7	82,245		21
					22
					23
					24
	11,563,641		11,563,641		25
					26
					27
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					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	332,020,353		
4	Transmission	14,885,959		
5	Regional Market			
6	Distribution	35,227,597		
7	Customer Accounts	30,292,218		
8	Customer Service and Informational	8,171,252		
9	Sales	7,936,976		
10	Administrative and General	133,003,559		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	561,537,914		
12	Maintenance			
13	Production	232,907,543		
14	Transmission	8,094,535		
15	Regional Market			
16	Distribution	38,128,893		
17	Administrative and General	589,446		
18	TOTAL Maintenance (Total of lines 13 thru 17)	279,720,417		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	564,927,896		
21	Transmission (Enter Total of lines 4 and 14)	22,980,494		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	73,356,490		
24	Customer Accounts (Transcribe from line 7)	30,292,218		
25	Customer Service and Informational (Transcribe from line 8)	8,171,252		
26	Sales (Transcribe from line 9)	7,936,976		
27	Administrative and General (Enter Total of lines 10 and 17)	133,593,005		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	841,258,331	5,761,902	847,020,233
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	841,258,331	5,761,902	847,020,233
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	215,530,608	20,329,989	235,860,597
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	215,530,608	20,329,989	235,860,597
72	Plant Removal (By Utility Departments)			
73	Electric Plant	28,079,276		28,079,276
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	28,079,276		28,079,276
77	Other Accounts (Specify, provide details in footnote):			
78	Non-Regulated Products & Services	4,179,290		4,179,290
79	Other Work in Progress	8,568,547		8,568,547
80	Other Accounts	3,143,163		3,143,163
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	15,891,000		15,891,000
96	TOTAL SALARIES AND WAGES	1,100,759,215	26,091,891	1,126,851,106

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	2,573,885	3,520,912	7,593,991	14,224,030
3	Net Sales (Account 447)	723,861	1,091,399	1,174,453	1,183,257
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	3,297,746	4,612,311	8,768,444	15,407,287

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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			179,929			1,830,528
2	Reactive Supply and Voltage	97,560	MWH	170,680	7,635,468	MWH	7,082,087
3	Regulation and Frequency Response						520,965
4	Energy Imbalance	13,463,399	MWH	1,606,671	13,505,044	MWH	138,565
5	Operating Reserve - Spinning						1,369,973
6	Operating Reserve - Supplement						1,369,973
7	Other	582,268	MWH	1,548,354	37,900	MWH	206,583
8	Total (Lines 1 thru 7)	14,143,227		3,505,634	21,178,412		12,518,674

Schedule Page: 398 Line No.: 1 Column: g

$439,648 is based on upon $/MWH and $7,635,468 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

$2,683,047 is based upon $/MWH and $7,635,468 MWH. The remainder is based upon Load Ratio Share (LRS) calculation. The LRS calculation uses a twelve month rolling average from coincidental peak demand.

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

Energy Imbalance is also reported on FERC Form 1 pages 326-327.

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

Energy Imbalance is also reported on FERC Form 1, pages 326-327.

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

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.: 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

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

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

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

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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	21,819	9	9	13,849	4,346	2,324		1,300	
2	February	18,479	10	8	12,040	3,469	2,346		624	
3	March	20,275	16	8	12,821	3,927	2,346		1,181	
4	Total for Quarter 1				38,710	11,742	7,016		3,105	
5	April	17,333	29	17	11,491	3,355	2,333		154	
6	May	19,348	19	16	13,103	3,622	2,346		277	
7	June	20,734	15	16	13,931	4,054	2,094		655	
8	Total for Quarter 2				38,525	11,031	6,773		1,086	
9	July	22,305	12	17	15,014	4,540	2,146		605	
10	August	22,493	17	16	15,485	4,557	2,146		305	
11	September	20,189	27	17	13,809	3,929	2,146		305	
12	Total for Quarter 3				44,308	13,026	6,438		1,215	
13	October	19,606	11	17	13,217	3,784	2,146		459	
14	November	17,583	20	8	12,126	3,325	2,132			
15	December	19,532	13	8	12,966	3,804	2,146		616	
16	Total for Quarter 4				38,309	10,913	6,424		1,075	
17	Total Year to Date/Year				159,852	46,712	26,651		6,481	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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									

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	77,435,296
3	Steam	25,693,083			
4	Nuclear	44,387,028	23	Requirements Sales for Resale (See instruction 4, page 311.)	8,052,479
5	Hydro-Conventional	1,517,922			
6	Hydro-Pumped Storage	3,397,841	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,818,789
7	Other	10,970,939			
8	Less Energy for Pumping	4,265,898	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	81,700,915	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	158,616
10	Purchases	9,478,719	27	Total Energy Losses	4,463,282
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	91,928,462
12	Received	8,108,954			
13	Delivered	7,462,847			
14	Net Exchanges (Line 12 minus line 13)	646,107			
15	Transmission For Other (Wheeling)				
16	Received	34,597,442			
17	Delivered	34,494,721			
18	Net Transmission for Other (Line 16 minus line 17)	102,721			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	91,928,462			

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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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	7,834,913	115,259	16,743	9	900
30	February	6,445,260	48,887	14,118	10	800
31	March	7,551,125	389,667	15,524	16	800
32	April	6,921,299	359,803	12,661	29	1700
33	May	7,460,935	177,223	14,626	17	1600
34	June	8,122,986	128,801	16,078	15	1600
35	July	9,219,474	92,182	17,342	20	1700
36	August	8,842,111	139,217	17,422	17	1500
37	September	7,420,592	116,582	15,441	27	1600
38	October	7,100,928	97,733	15,027	11	1600
39	November	6,977,360	45,821	13,408	20	800
40	December	8,031,479	107,614	15,088	13	800
41	TOTAL	91,928,462	1,818,789			

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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)	2250			2066		
7	Plant Hours Connected to Load	7022			8596		
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	180			194		
12	Net Generation, Exclusive of Plant Use - KWh	9608222000			9224649000		
13	Cost of Plant: Land and Land Rights	21851141			5829127		
14	Structures and Improvements	297642853			83536992		
15	Equipment Costs	1753575968			1459928094		
16	Asset Retirement Costs	210058922			234867573		
17	Total Cost	2283128884			1784161786		
18	Cost per KW of Installed Capacity (line 17/5) Including	916.4776			841.9829		
19	Production Expenses: Oper, Supv, & Engr	3899739			4364772		
20	Fuel	271578920			276206861		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	17385445			16064347		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	22			18		
25	Electric Expenses	1366824			2278529		
26	Misc Steam (or Nuclear) Power Expenses	6145676			4681930		
27	Rents	0			0		
28	Allowances	2452			2303		
29	Maintenance Supervision and Engineering	4214764			3500405		
30	Maintenance of Structures	4860185			4657275		
31	Maintenance of Boiler (or reactor) Plant	17651580			13807262		
32	Maintenance of Electric Plant	8883829			13217205		
33	Maintenance of Misc Steam (or Nuclear) Plant	1798336			1718819		
34	Total Production Expenses	337787772			340499726		
35	Expenses per Net KWh	0.0352			0.0369		
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	3506001	57379	0	3517945	32005	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12456	137881	0	12422	137686	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	73.050	75.280	0.000	74.480	70.940	0.000
41	Average Cost of Fuel per Unit Burned	75.230	74.562	0.000	76.750	70.185	0.000
42	Average Cost of Fuel Burned per Million BTU	3.020	12.875	0.000	3.089	12.137	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.028	0.000	0.030	0.030	0.000
44	Average BTU per KWh Net Generation	9167.000	9167.000	0.000	9495.000	9495.000	0.000

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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	1849			0		
20	Fuel	301259			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	60155			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			418		
26	Misc Steam (or Nuclear) Power Expenses	702227			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	15218			0		
30	Maintenance of Structures	-8924453			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	210			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	41049			0		
34	Total Production Expenses	-7802486			418		
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

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Buck* (b)			Plant Name: *Buck* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Combustion Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1953			1970		
4	Year Last Unit was Installed	1953			1970		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	1203			702528		
20	Fuel	13660			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	195			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			980		
26	Misc Steam (or Nuclear) Power Expenses	24115			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	430393			321		
30	Maintenance of Structures	120755			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1616			9900		
33	Maintenance of Misc Steam (or Nuclear) Plant	5930			0		
34	Total Production Expenses	597867			713729		
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

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *McGuire* (b)			Plant Name: *Catawba* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear			Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1981			1985		
4	Year Last Unit was Installed	1984			1986		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2440.60			463.90		
6	Net Peak Demand on Plant - MW (60 minutes)	2398			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	1262			1091		
12	Net Generation, Exclusive of Plant Use - KWh	18795536000			3792748210		
13	Cost of Plant: Land and Land Rights	595904			779551		
14	Structures and Improvements	684130158			244082998		
15	Equipment Costs	2566386032			581052016		
16	Asset Retirement Costs	-303637730			-11991426		
17	Total Cost	2947474364			813923139		
18	Cost per KW of Installed Capacity (line 17/5) Including	1207.6843			1754.5228		
19	Production Expenses: Oper, Supv, & Engr	18076929			3697312		
20	Fuel	134756913			27145414		
21	Coolants and Water (Nuclear Plants Only)	3621456			945207		
22	Steam Expenses	23647951			4085137		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2562587			521152		
26	Misc Steam (or Nuclear) Power Expenses	77516844			14678191		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	27291588			5231416		
30	Maintenance of Structures	5057237			1298328		
31	Maintenance of Boiler (or reactor) Plant	44602120			8094387		
32	Maintenance of Electric Plant	28163889			4128979		
33	Maintenance of Misc Steam (or Nuclear) Plant	18946059			4284285		
34	Total Production Expenses	384243573			74109808		
35	Expenses per Net KWh	0.0204			0.0195		
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	188259000	0	2976388	197817000	0	2768063
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	45.228	0.000	0.000	50.854	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.715	0.000	0.000	0.711	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.007	0.000	0.000	0.007	0.000
44	Average BTU per KWh Net Generation	0.000	10016.000	0.000	0.000	10038.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Dan River* (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional					
3	Year Originally Constructed	2012					
4	Year Last Unit was Installed	2012					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	697.90			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	715			0		
7	Plant Hours Connected to Load	8219			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	706			0		
10	When Limited by Condenser Water	662			0		
11	Average Number of Employees	45			0		
12	Net Generation, Exclusive of Plant Use - KWh	4891418000			0		
13	Cost of Plant: Land and Land Rights	119364			0		
14	Structures and Improvements	145134556			0		
15	Equipment Costs	510717011			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	655970931			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	939.9211			0		
19	Production Expenses: Oper, Supv, & Engr	1487364			0		
20	Fuel	127948202			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	2294162			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	865469			0		
30	Maintenance of Structures	1989670			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	5897648			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	140482515			0		
35	Expenses per Net KWh	0.0287			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	Barrels				
38	Quantity (Units) of Fuel Burned	33685427	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1036	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.796	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.796	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.663	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7137.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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			163.20			108.00			5
1103			168			97			6
2550			610			1194			7
0			0			0			8
1161			173			82			9
1098			170			84			10
110			48			0			11
994305000			40117000			87276000			12
584928			167823			0			13
85891781			15117907			546489			14
1079757877			79878979			59517954			15
175098292			0			0			16
1341332878			95164709			60064443			17
1168.0015			583.1171			556.1523			18
2220435			1165272			319605			19
40312353			2284241			4295687			20
0			0			0			21
5275110			764158			0			22
0			0			0			23
10			1			0			24
1512109			364105			326829			25
2344851			1022161			0			26
0			0			0			27
193			1			0			28
1925823			400255			-242537			29
2079344			548522			306802			30
3150699			37750			0			31
4451272			415596			654186			32
497051			1417083			0			33
63769250			8419145			5660572			34
0.0641			0.2099			0.0649			35
Coal	Oil		Coal	Oil	Gas	Gas	Oil		36
Tons	Barrels		Tons	Barrels	MCF	MCF	Barrels		37
471035	27376	0	0	0	571707	826962	9999	0	38
11487	137780	0	0	0	1031	1029	137000	0	39
75.230	71.910	0.000	0.000	0.000	3.955	3.985	74.140	0.000	40
78.470	71.445	0.000	0.000	0.000	3.955	3.985	99.070	0.000	41
3.415	12.346	0.000	0.000	0.000	3.837	3.873	17.218	0.000	42
0.039	0.039	0.000	0.000	0.000	0.056	0.049	0.049	0.000	43
11047.000	11047.000	0.000	0.000	0.000	14688.000	10408.000	10408.000	0.000	44

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
		7657			0			0	7
		0			0			0	8
		1400			0			0	9
		1388			0			0	10
		116			0			0	11
		5825790000			0			0	12
		597577			0			0	13
		244262653			0			0	14
		2592827509			315010			360253	15
		179964900			0			0	16
		3017652639			315010			360253	17
		1971.6776			0			0	18
		3164301			-23			0	19
		184241299			1562			0	20
		0			0			0	21
		14692590			0			0	22
		0			0			0	23
		13			0			0	24
		1878782			0			0	25
		3219336			43091			0	26
		0			0			0	27
		471			0			0	28
		2907691			354			0	29
		2046754			98480			0	30
		9011294			0			0	31
		2843148			169			0	32
		1180732			3440			0	33
		225186411			147073			0	34
		0.0387			0.0000			0.0000	35
Coal	Oil		Coal	Oil		Gas	Oil		36
Tons	Barrels		Tons	Barrels		MCF	Barrels		37
2160861	60491	0	0	0	0	0	0	0	38
12131	137494	0	0	0	0	0	0	0	39
77.990	78.170	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
81.200	79.908	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
3.347	13.837	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.031	0.031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
9058.000	9058.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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			827			2624	6
		0			125			8760	7
		0			0			0	8
		0			1488			2618	9
		0			1193			2554	10
		0			13			1325	11
		0			17603000			21798744000	12
		0			3021923			1504454	13
		0			28611853			957083439	14
		0			374970892			3303779748	15
		0			0			-291973683	16
		0			406604668			3970393958	17
		0			231.8685			1488.8791	18
		0			431431			14533404	19
		0			1502669			146462782	20
		0			0			4317878	21
		0			0			21390708	22
		0			0			0	23
		0			0			0	24
		-687			2954101			18219375	25
		0			0			90544616	26
		0			0			0	27
		0			0			0	28
		0			936213			40743246	29
		0			636088			6181473	30
		0			0			34066488	31
		0			1759608			25543770	32
		0			0			22700507	33
		-687			8220110			424704247	34
		0.0000			0.4670			0.0195	35
Coal	Oil		Gas	Oil		MBTUs	Nuclear	Grams of	36
Tons	Barrels		MCF	Barrels				Uranium	37
0	0	0	324512	1374	0	221679000	0	3450475	38
0	0	0	1037	138513	0	0	0	0	39
0.000	0.000	0.000	3.799	70.860	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	3.799	80.463	0.000	0.000	42.427	0.000	41
0.000	0.000	0.000	3.665	13.830	0.000	0.000	0.661	0.000	42
0.000	0.000	0.000	0.076	0.076	0.000	0.000	0.007	0.000	43
0.000	0.000	0.000	19565.000	19565.000	0.000	0.000	10169.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *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			697.90			5
717			896			716			6
265			1303			8598			7
0			0			0			8
739			895			697			9
563			825			668			10
9			12			47			11
46843000			678171000			5111562000			12
5063537			967095			0			13
29643614			3351892			146198564			14
221318821			296033334			521616836			15
0			0			0			16
256025972			300352321			667815400			17
320.3528			307.2658			956.8927			18
251350			494473			1533908			19
4164043			27010058			132145348			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
1558184			1792533			1824148			25
0			0			0			26
0			0			0			27
0			0			0			28
484828			600979			763178			29
286383			336284			3586800			30
0			0			0			31
1011780			1874513			1414178			32
0			0			0			33
7756568			32108840			141267560			34
0.1656			0.0473			0.0276			35
Gas	Oil		Gas	Oil		Gas	Oil		36
MCF	Barrels		MCF	Barrels		MCF	Barrels		37
534224	18734	0	7185779	5937	0	34837558	0	0	38
1032	137390	0	1039	139834	0	1036	0	0	39
3.716	0.000	0.000	3.679	0.000	0.000	3.791	0.000	0.000	40
3.716	112.436	0.000	3.679	81.837	0.000	3.791	0.000	0.000	41
3.601	19.485	0.000	3.542	13.935	0.000	3.659	0.000	0.000	42
0.087	0.087	0.000	0.040	0.040	0.000	0.026	0.000	0.000	43
14072.000	14072.000	0.000	11055.000	11055.000	0.000	7063.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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: 403 Line No.: 20 Column: f

Lee Combustion Turbine Total fuel costs exclude $508,888 for Lee CC pre-commercial generation.

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 $247,720 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.

Schedule Page: 403.1 Line No.: 20 Column: e

Riverbend Steam Total fuel costs reflect Sale of Fly Ash.

Riverbend Steam Accounts 0501007, 0501008, and 0501009 for Coal Ash Beneficial Reuse in the amount of $91,694,725 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.: 20 Column: b

Dan River Combined Cycle Total fuel costs include Biogas accounts 0547106 and 0547107 in the amount of $591,816

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.: 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: 402.2 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 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2232 Plant Name: Bridgewater (b)	FERC Licensed Project No. 2232 Plant Name: Rhodhiss (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	2011	1925
4	Year Last Unit was Installed	2011	1925
5	Total installed cap (Gen name plate Rating in MW)	27.73	25.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	35	37
7	Plant Hours Connect to Load	3,218	5,620
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	3	4
12	Net Generation, Exclusive of Plant Use - Kwh	51,905,000	61,738,000
13	Cost of Plant		
14	Land and Land Rights	1,229,866	525,914
15	Structures and Improvements	65,117,164	4,003,189
16	Reservoirs, Dams, and Waterways	105,399,463	7,546,537
17	Equipment Costs	35,540,185	19,142,063
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	207,286,678	31,217,703
21	Cost per KW of Installed Capacity (line 20 / 5)	7,475.1777	1,224.2236
22	Production Expenses		
23	Operation Supervision and Engineering	297,684	138,860
24	Water for Power	0	0
25	Hydraulic Expenses	-117,356	-6,913
26	Electric Expenses	149,781	125,078
27	Misc Hydraulic Power Generation Expenses	135,500	127,410
28	Rents	0	0
29	Maintenance Supervision and Engineering	27,733	30,308
30	Maintenance of Structures	2,146	9,704
31	Maintenance of Reservoirs, Dams, and Waterways	210,609	57,889
32	Maintenance of Electric Plant	78,103	53,098
33	Maintenance of Misc Hydraulic Plant	76,828	76,009
34	Total Production Expenses (total 23 thru 33)	861,028	611,443
35	Expenses per net KWh	0.0166	0.0099

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	166	72
7	Plant Hours Connect to Load	1,472	8,399
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	15	8
12	Net Generation, Exclusive of Plant Use - Kwh	120,352,000	98,272,000
13	Cost of Plant		
14	Land and Land Rights	12,451,413	2,707,611
15	Structures and Improvements	16,410,674	6,476,079
16	Reservoirs, Dams, and Waterways	32,511,353	19,141,813
17	Equipment Costs	58,841,608	21,971,673
18	Roads, Railroads, and Bridges	2,240,416	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	122,455,464	50,297,176
21	Cost per KW of Installed Capacity (line 20 / 5)	349.8728	838.2863
22	Production Expenses		
23	Operation Supervision and Engineering	1,891,432	302,226
24	Water for Power	0	0
25	Hydraulic Expenses	-553,498	-170,600
26	Electric Expenses	307,063	133,084
27	Misc Hydraulic Power Generation Expenses	1,240,890	298,300
28	Rents	0	0
29	Maintenance Supervision and Engineering	360,215	59,854
30	Maintenance of Structures	12,949	4,580
31	Maintenance of Reservoirs, Dams, and Waterways	152,735	61,763
32	Maintenance of Electric Plant	583,832	182,719
33	Maintenance of Misc Hydraulic Plant	241,185	164,457
34	Total Production Expenses (total 23 thru 33)	4,236,803	1,036,383
35	Expenses per net KWh	0.0352	0.0105

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2232 Plant Name: Rocky Creek (b)	FERC Licensed Project No. 2232 Plant Name: Cedar Creek (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1909	1926
4	Year Last Unit was Installed	1909	1926
5	Total installed cap (Gen name plate Rating in MW)	28.00	45.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	48
7	Plant Hours Connect to Load	0	8,036
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	4
12	Net Generation, Exclusive of Plant Use - Kwh	-164,000	113,070,000
13	Cost of Plant		
14	Land and Land Rights	36,552	7,899
15	Structures and Improvements	1,198,093	3,527,794
16	Reservoirs, Dams, and Waterways	3,534,847	6,701,676
17	Equipment Costs	79,490	16,245,223
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	4,848,982	26,482,592
21	Cost per KW of Installed Capacity (line 20 / 5)	173.1779	588.5020
22	Production Expenses		
23	Operation Supervision and Engineering	95,604	185,006
24	Water for Power	0	0
25	Hydraulic Expenses	21,071	15
26	Electric Expenses	18,463	173,032
27	Misc Hydraulic Power Generation Expenses	102,395	222,180
28	Rents	0	0
29	Maintenance Supervision and Engineering	27,319	43,970
30	Maintenance of Structures	493	10,727
31	Maintenance of Reservoirs, Dams, and Waterways	108,822	52,399
32	Maintenance of Electric Plant	23,952	71,679
33	Maintenance of Misc Hydraulic Plant	33,234	123,367
34	Total Production Expenses (total 23 thru 33)	431,353	882,375
35	Expenses per net KWh	0.0000	0.0078

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	157.60	21.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	144	22
7	Plant Hours Connect to Load	402	3,728
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	6	4
12	Net Generation, Exclusive of Plant Use - Kwh	31,780,000	65,193,000
13	Cost of Plant		
14	Land and Land Rights	21,905,557	1,153,815
15	Structures and Improvements	8,237,027	2,896,279
16	Reservoirs, Dams, and Waterways	17,440,014	4,897,153
17	Equipment Costs	89,753,525	3,529,514
18	Roads, Railroads, and Bridges	0	46,024
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	137,336,123	12,522,785
21	Cost per KW of Installed Capacity (line 20 / 5)	871.4221	579.7586
22	Production Expenses		
23	Operation Supervision and Engineering	91,467	183,306
24	Water for Power	0	0
25	Hydraulic Expenses	-212,793	68,840
26	Electric Expenses	1,220,457	6,224
27	Misc Hydraulic Power Generation Expenses	336,181	76,554
28	Rents	0	0
29	Maintenance Supervision and Engineering	48,676	51,820
30	Maintenance of Structures	109,371	141,783
31	Maintenance of Reservoirs, Dams, and Waterways	473,782	56,071
32	Maintenance of Electric Plant	866,858	30,647
33	Maintenance of Misc Hydraulic Plant	238,414	199,458
34	Total Production Expenses (total 23 thru 33)	3,172,413	814,703
35	Expenses per net KWh	0.0998	0.0125

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2232 Plant Name: Oxford (d)	FERC Licensed Project No. 2232 Plant Name: Lookout Shoals (e)	FERC Licensed Project No. 2232 Plant Name: Mountain Island (f)	Line No.
Storage	Run-of-River	Storage	1
Conventional	Conventional	Conventional	2
1928	1915	1923	3
1928	1915	1923	4
36.00	25.80	60.00	5
23	31	62	6
1,065	8,750	2,742	7
			8
44	28	62	9
40	28	58	10
3	1	1	11
59,387,000	87,427,000	90,428,000	12
			13
1,247,589	550,590	800,211	14
4,009,902	2,536,303	2,367,161	15
26,382,458	5,662,643	5,531,690	16
22,353,467	13,189,657	19,454,392	17
0	0	0	18
0	0	0	19
53,993,416	21,939,193	28,153,454	20
1,499.8171	850.3563	469.2242	21
			22
113,945	71,395	267,587	23
0	0	0	24
-77,006	22,422	-26,551	25
119,975	172,919	121,570	26
181,463	122,932	222,381	27
0	0	0	28
39,842	25,274	67,462	29
689	7,948	5,641	30
56,889	52,012	46,074	31
114,487	228,769	102,275	32
243,685	141,527	30,849	33
793,969	845,198	837,288	34
0.0134	0.0097	0.0093	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2232 Plant Name: Fishing Creek (d)	FERC Licensed Project No. 2232 Plant Name: Great Falls (e)	FERC Licensed Project No. 2232 Plant Name: Dearborn (f)	Line No.
Storage	Run-of-River	Run-of-River	1
Conventional	Conventional	Conventional	2
1916	1907	1923	3
1916	1907	1923	4
42.30	12.00	45.00	5
54	3	48	6
8,078	39	7,644	7
			8
56	14	47	9
49	11	42	10
3	5	2	11
111,618,000	-16,000	135,574,000	12
			13
364,037	27,613	0	14
4,376,021	90,259	2,137,143	15
15,283,129	0	1,506,206	16
27,274,267	189,236	15,933,123	17
0	0	633,636	18
0	0	0	19
47,297,454	307,108	20,210,108	20
1,118.1431	25.5923	449.1135	21
			22
195,633	62,866	143,474	23
0	0	0	24
26,207	4	15	25
179,435	9,645	176,882	26
168,681	229,356	280,429	27
0	0	0	28
40,825	14,923	44,693	29
5,582	-17,397	910	30
37,279	15,233	73,392	31
137,599	107,529	235,044	32
105,494	59,155	40,562	33
896,735	481,314	995,401	34
0.0080	0.0000	0.0073	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	12.00	0.00	5
92	18	0	6
8,760	8,746	0	7
			8
90	20	0	9
85	10	0	10
2	2	0	11
170,321,000	50,584,700	0	12
			13
627,436	151,343	0	14
9,056,227	1,258,479	0	15
15,013,969	11,666,336	0	16
26,813,920	11,643,402	0	17
0	0	0	18
0	0	0	19
51,511,552	24,719,560	0	20
919.8491	2,059.9633	0.0000	21
			22
460,600	169,882	0	23
0	0	0	24
42,863	47,975	0	25
164,285	101,422	0	26
247,993	194,331	0	27
0	0	0	28
56,736	17,790	0	29
50,542	43,395	0	30
81,890	113,096	0	31
507,676	279,487	0	32
161,721	27,485	0	33
1,774,306	994,863	0	34
0.0104	0.0197	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
4,345	3,770	0	7
			8
51	11	0	9
37	7	0	10
2	0	0	11
186,479,000	28,960,000	0	12
			13
469,013	475,718	0	14
2,167,386	355,878	0	15
10,944,994	4,890,494	0	16
6,807,416	2,545,532	0	17
239,971	72,590	0	18
0	0	0	19
20,628,780	8,340,212	0	20
477.5181	772.2419	0.0000	21
			22
343,726	93,995	0	23
0	0	0	24
43,033	0	0	25
81,885	3,917	0	26
228,968	36,985	0	27
0	0	0	28
163,548	3,623	0	29
303,967	1,311	0	30
117,622	32,516	0	31
168,071	29,448	0	32
165,038	119,401	0	33
1,615,858	321,196	0	34
0.0087	0.0111	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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

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Schedule Page: 406 Line No.: 10 Column: b

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Schedule Page: 406 Line No.: 10 Column: c

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Schedule Page: 406.1 Line No.: 10 Column: f

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Schedule Page: 406.1 Line No.: 11 Column: e

Remote control operation.

Schedule Page: 406.2 Line No.: 9 Column: b

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Schedule Page: 406.3 Line No.: 11 Column: b

Remote control operation.

Schedule Page: 406.3 Line No.: 11 Column: e

Remote control operation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 2503 Plant Name: Jocassee (b)
1	Type of Plant Construction (Conventional or Outdoor)	Outdoor
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)	778
6	Plant Hours Connect to Load While Generating	3,031
7	Net Plant Capability (in megawatts)	780
8	Average Number of Employees	9
9	Generation, Exclusive of Plant Use - Kwh	1,160,560,000
10	Energy Used for Pumping	1,410,615,000
11	Net Output for Load (line 9 - line 10) - Kwh	-250,055,000
12	Cost of Plant	
13	Land and Land Rights	5,273,013
14	Structures and Improvements	29,368,463
15	Reservoirs, Dams, and Waterways	49,709,478
16	Water Wheels, Turbines, and Generators	70,908,823
17	Accessory Electric Equipment	12,707,493
18	Miscellaneous Powerplant Equipment	3,445,715
19	Roads, Railroads, and Bridges	415,508
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	171,828,493
22	Cost per KW of installed cap (line 21 / 4)	242.0120
23	Production Expenses	
24	Operation Supervision and Engineering	659,663
25	Water for Power	
26	Pumped Storage Expenses	33,350
27	Electric Expenses	886,729
28	Misc Pumped Storage Power generation Expenses	1,747,330
29	Rents	
30	Maintenance Supervision and Engineering	601,586
31	Maintenance of Structures	238,681
32	Maintenance of Reservoirs, Dams, and Waterways	297,177
33	Maintenance of Electric Plant	995,518
34	Maintenance of Misc Pumped Storage Plant	441,506
35	Production Exp Before Pumping Exp (24 thru 34)	5,901,540
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	5,901,540
38	Expenses per KWh (line 37 / 9)	0.0051

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 2740 Plant Name: Bad Creek (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
Outdoor			1
1991			2
1991			3
1,065			4
1,398			5
3,341			6
1,360			7
35			8
2,237,281,000			9
2,855,285,000			10
-618,004,000			11
			12
1,145,342			13
228,018,939			14
455,268,967			15
235,645,719			16
57,466,038			17
28,135,649			18
17,869,699			19
			20
1,023,550,353			21
961.0801			22
			23
1,309,629			24
			25
-937			26
1,162,972			27
2,358,121			28
			29
852,251			30
297,523			31
452,747			32
1,420,808			33
1,076,297			34
8,929,411			35
			36
8,929,411			37
0.0040			38

Schedule Page: 408 Line No.: 36 Column: b

Total pumping expenses for all pumped storage hydro units, consisting of fuel costs associated with Kwh reported on Line 10, are estimated to be $98,657,287.

Schedule Page: 408 Line No.: 36 Column: c

Total pumping expenses for all pumped storage hydro units, consisting of fuel costs associated with Kwh reported on Line 10, are estimated to be $98,657,287.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	1,229,000	11,323,982
3	Bryson - Project 2601	1925	1.00	1.0	4,400,100	6,547,000
4	Cedar Cliff - Project 2698	1952	6.40	7.0	15,207,000	7,234,174
5	Franklin - Project 2603	1925	1.00	1.0	3,043,900	8,141,009
6	Gaston Shoals - Project 2332	1908	5.30	5.0	5,789,010	20,329,993
7	Missions - Project 2619	1924	1.80	2.0	3,640,000	8,107,147
8	Queen's Creek - Project 2694	1949	1.40	2.0	2,822,000	1,318,518
9	Tuckasegee - Project 2686	1950	3.00	3.0	4,188,000	3,772,932
10	Tuxedo	1920	5.00	8.0	14,694,000	10,916,239
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12						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
1,258,220	111,209		110,681			2
6,547,000	101,332		93,402			3
1,130,340	68,528		64,690			4
8,141,009	67,524		68,924			5
3,835,848	458,291		462,643			6
4,503,971	149,364		374,622			7
941,799	50,716		223,521			8
1,257,644	110,973		131,434			9
2,183,248	177,686		229,292			10
						11
						12
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Antioch Tie	Appalachian Power	525.00	525.00	Tower	27.89		1
2	Cliffside Steam Sta #6	McGuire SW	525.00	525.00	Tower	48.70		1
3	Cliffside Stm	Cliffside SW	525.00	525.00	Tower & Pole	1.14		1
4	Jocassee Tie	Bad Creek HYD	525.00	525.00	Tower	9.27		1
5	Jocassee Tie	Cliffside Tie	525.00	525.00	Tower	70.57		1
6	McGuire SW	Antioch Tie	525.00	525.00	Tower	54.83		1
7	MCGuire SW	Woodleaf Switching	525.00	525.00	Tower	29.96		1
8	Newport Tie	Progress Energy Rockingham	525.00	525.00	Tower	48.33		1
9	Newport Tie	McGuire Switching	525.00	525.00	Tower & Pole	32.43		1
10	Oconee Nuclear	Newport Tie	525.00	525.00	Tower	107.47		1
11	Oconee Nuclear	South Hall	525.00	525.00	Tower & Pole	22.46		1
12	Oconee Nuclear	Jocassee Tie	525.00	525.00	Tower	20.89		1
13	Pleasant Garden Tie	Parkwood Tie	525.00	525.00	Tower	49.29		1
14	Woodleaf Switching	Pleasant Garden Tie	525.00	525.00	Tower	52.75		1
15								
16	TOTAL 525 KV LINES					575.98		14
17								
18	Allen Steam	Catawba Nuclear	230.00	230.00	Tower	10.91		2
19	Allen Steam	Riverbend Steam	230.00	230.00	Tower	12.58		2
20	Allen Steam	Winecoff Tie	230.00	230.00	Tower	32.17		2
21	Allen Steam	Woodlawn Tie	230.00	230.00	Tower & Pole	8.40		2
22	Anderson Tie	Hodges Tie	230.00	230.00	Tower	25.69		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	28.29		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	14.90		2
35	Catawba Nuclear	Ripp Switching Station	230.00	230.00	Tower	24.32		2
36					TOTAL	8,242.91	43.89	2,430

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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	1.67		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	15.77		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	21.38		2
10	Hartwell Hydro	Anderson Tie	230.00	230.00	Tower	11.97		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	36.19		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	8,242.91	43.89	2,430

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	Pleasant GardenTie	Eno Tie	230.00	230.00	Tower	42.52		2
2	Ripp Switching	Riverview Switching	230.00	230.00	Tower	9.68		2
3	Ripp Switching	Shelby Tie	230.00	230.00	Tower	9.96		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	5.63		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	18.29		2
14	Winecoff Tie	Buck Tie	230.00	230.00	Tower	24.09		2
15								
16	TOTAL 230 KV LINES					1,394.24		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	54.93		5
34	100 KV Lines		100.00	100.00	Tower	746.05		235
35	100 KV Lines		100.00	100.00	Pole	188.70		245
36					TOTAL	8,242.91	43.89	2,430

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	100 KV Lines		100.00	100.00	Underground	5.47		7
2	100 kV Lines		100.00		Tower & Pole	2,616.40		399
3	TOTAL 100 - 138 KV LINES					3,618.05		892
4								
5	66 KV Lines		66.00	66.00	Pole	101.01		25
6	66 KV Lines		66.00	66.00	Tower & Pole	4.56		3
7								
8	TOTAL 66 KV LINES					105.57		28
9								
10	44 KV Lines		44.00	44.00	Tower	0.14		8
11	44 KV Lines		44.00	44.00	Pole	1,408.48		1,038
12	44 KV Lines		44.00	44.00	Underground	7.39		15
13	44 kV Lines		44.00	44.00	Tower & Pole	933.35		193
14	TOTAL 44 KV LINES					2,349.36		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	49.36		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	26.41		52
20	4 to 12 KV Lines		12.00	12.00	Underground	0.24		2
21								
22	TOTAL 4-33 KV LINES					92.98		95
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,242.91	43.89	2,430

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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
2515								1
2515								2
2515								3
2515								4
2515								5
2515								6
2515								7
2515								8
2515								9
2515								10
2515								11
2515								12
2515								13
2515								14
	20,656,136	106,928,868	127,585,004					15
	20,656,136	106,928,868	127,585,004					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
	178,391,379	1,803,928,976	1,982,320,355	1,068,110	15,868,015		16,936,125	36

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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
	178,391,379	1,803,928,976	1,982,320,355	1,068,110	15,868,015		16,936,125	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) 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	274,984,540	316,378,249					15
	41,393,709	274,984,540	316,378,249					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	111,186,644	114,923,183					29
	3,736,539	111,186,644	114,923,183					30
								31
477								32
								33
								34
								35
	178,391,379	1,803,928,976	1,982,320,355	1,068,110	15,868,015		16,936,125	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) 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
	76,790,048	888,517,198	965,307,246					2
	76,790,048	888,517,198	965,307,246					3
								4
								5
								6
	5,793,848	38,065,793	43,859,641					7
	5,793,848	38,065,793	43,859,641					8
								9
								10
								11
								12
	29,591,521	376,319,040	405,910,561					13
	29,591,521	376,319,040	405,910,561					14
								15
								16
								17
								18
								19
								20
	429,578	7,926,893	8,356,471					21
	429,578	7,926,893	8,356,471					22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
				1,068,110	15,868,015		16,936,125	35
	178,391,379	1,803,928,976	1,982,320,355	1,068,110	15,868,015		16,936,125	36

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) X An Original (2) __ A Resubmission	04/12/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: h

For column (h) the number of circuits - 1 & 2

Schedule Page: 422 Line No.: 1 Column: i

All Conductors in column (i) are ACSR shown in MCM.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	Sun City Retail Tap		0.11	Poles	27.30	1	1
3	Monroe Solar Tap		0.05	Poles	20.50	1	1
4	Dixon School Rd Sw Sta Svc		0.04	Poles	23.50	1	1
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15	Major Rebuilds / Removals						
16	Victor Hill Tap 44 to 100 conv		3.83	Towers	7.30	1	1
17	Dixon School Rd Sw Sta		0.06	Towers	50.00	2	2
18	Stonewater Tie (line relocate)	Conley Switching Station	0.23	Towers	13.00	2	2
19	Stonewater Tie (line relocate)	Lincolnton Tie	0.27	Towers	11.30	2	2
20	Stonewater Tie (line relocate)	Westfork Switching Station	0.27	Towers	11.00	2	2
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		4.86		163.90	12	12

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 KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
556	ACSR		100		184,137	75,552		259,689	2
556	ACSR		100		122,333	171,212		293,545	3
556	ACSR		44		36,795	15,164		51,959	4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
556	ACSR		100			458,450	25,335	483,785	16
795	ACSR	Dbl horiz	230		1,665,645	627,864		2,293,509	17
1272	ACSR		100		348,755	170,890	117,488	637,133	18
795	ACSS/TW		100		520,154	68,660	742	589,556	19
477	ACSR	Dbl horiz	100		865,582	301,470	51,997	1,219,049	20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					3,743,401	1,889,262	195,562	5,828,225	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	500.00	24.00	24.00
32	BAD CREEK HYDRO BAD CREEK SC	TRANS	500.00	24.00	24.00
33	BAD CREEK HYDRO BAD CREEK SC	TRANS	500.00	24.00	24.00
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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BEECH ST RET HENDERSONVILLE NC	DIST	44.00	2.40	
2	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 Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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 Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
2	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 Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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 Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	

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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	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	

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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	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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 Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(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	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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

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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	CORNING CABLE SYSTEMS T&D HICKORY NC	DIST	44.00	6.90	
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	2.40
29	CORONACA RET CORONACA SC	DIST	44.00	13.00	
30	CORONACA RET CORONACA SC	DIST	44.00	13.00	
31	CORONACA TIE CORONACA SC	TRANS	100.00	44.00	
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	24.00	0.20	
35	COTTONWOOD RET CORNELIUS NC	DIST	100.00	13.00	
36	COUNTRYSIDE RD RET KINGS MOUNTAIN NC	DIST	100.00	24.00	
37	COUNTRYSIDE RD RET KINGS MOUNTAIN NC	DIST	100.00	24.00	
38	COWANS FORD HYDRO STANLEY NC	TRANS	230.00	13.00	13.00
39	COWANS FORD HYDRO STANLEY NC	TRANS	230.00	13.00	13.00
40	COWANS FORD HYDRO STANLEY NC	TRANS	13.00	0.60	

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SUBSTATIONS

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1	COWANS FORD HYDRO STANLEY NC	TRANS	13.00	0.60	
2	COWANS FORD HYDRO STANLEY NC	TRANS	44.00	0.60	
3	COWPENS RET COWPENS SC	DIST	44.00	6.90	2.40
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	13.00	
8	CREST ST RET DURHAM NC	DIST	100.00	6.90	
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	CRETO TIE NINETY SIX SC	TRANS	100.00	44.00	
16	CRUMP RD RET HUDSON NC	DIST	100.00	13.00	
17	CRUMP RD RET HUDSON NC	DIST	100.00	13.00	
18	CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	
19	CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	
20	CYCLE RET ELKIN NC	DIST	44.00	13.00	
21	CYCLE RET ELKIN NC	DIST	44.00	13.00	
22	CYPRESS TIE ABBEVILLE SC	TRANS	100.00	44.00	
23	CYPRESS TIE ABBEVILLE SC	TRANS	100.00	44.00	
24	CYPRESS TIE ABBEVILLE SC	TRANS	24.00	0.20	
25	DACIAN AVE RET DURHAM NC	DIST	100.00	24.00	
26	DACIAN AVE RET DURHAM NC	DIST	100.00	24.00	
27	DALLAS CITY DEL 2 DALLAS NC	DIST	44.00	13.00	
28	DALLAS CITY DEL 2 DALLAS NC	DIST	44.00	13.00	
29	DAN RIVER STEAM STA EDEN NC	TRANS	138.00	100.00	13.80
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	2.40	0.60	
34	DAN VALLEY RET STONEVILLE NC	DIST	100.00	13.00	
35	DAN VALLEY RET STONEVILLE NC	DIST	100.00	13.00	
36	DANBURY RET DANBURY NC	DIST	44.00	24.00	13.00
37	DANIELS RET GREENVILLE SC	DIST	100.00	13.00	
38	DANIELS RET GREENVILLE SC	DIST	100.00	13.00	
39	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
40	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	13.00	
4	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
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 RIVER RET PISGAH FOREST NC	TRANS	100.00	13.00	
8	DAVIS RET WILLIAMSTON SC	DIST	100.00	13.00	
9	DEARBORN HYDRO GREAT FALLS SC	TRANS	100.00	66.00	
10	DEARBORN HYDRO GREAT FALLS SC	TRANS	44.00	6.90	
11	DEARBORN HYDRO GREAT FALLS SC	TRANS	44.00	6.90	
12	DEERFIELD RET MOORESVILLE NC	DIST	100.00	13.00	
13	DENNY RD RET GREENSBORO NC	DIST	100.00	24.00	
14	DENNY RD RET GREENSBORO NC	DIST	100.00	24.00	
15	DENNY RD RET GREENSBORO NC	DIST	100.00	24.00	
16	DENTON RET DENTON NC	DIST	100.00	13.00	
17	DEPOT ST RET FRANKLIN NC	DIST	66.00		
18	DEPOT ST RET FRANKLIN NC	DIST	69.00	13.00	
19	DERITA RET CHARLOTTE NC	DIST	100.00	24.00	
20	DERITA RET CHARLOTTE NC	DIST	100.00	24.00	
21	DERITA RET CHARLOTTE NC	DIST	100.00	24.00	
22	DILWORTH DIST CHARLOTTE NC	DIST	24.00	2.40	0.60
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	6.90	2.40
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	DIXIE TIE GASTONIA NC	TRANS	100.00	44.00	
31	DIXIE TIE GASTONIA NC	TRANS	100.00	44.00	
32	DIXIE TIE GASTONIA NC	TRANS	100.00	0.20	
33	DIXON RET ANDERSON SC	DIST	100.00	13.00	
34	DOBSON RET DOBSON NC	DIST	44.00	6.90	
35	DOBSON RET DOBSON NC	DIST	44.00	6.90	
36	DOBSON RET DOBSON NC	DIST	44.00	6.90	2.40
37	DOBSON RET DOBSON NC	DIST	44.00	6.90	2.40
38	DOCHENO RET HONEA PATH SC	DIST	44.00	13.00	
39	DOCHENO RET HONEA PATH SC	DIST	44.00	13.00	
40	DRAKA COMTEQ T&D CLAREMONT NC	DIST	100.00	24.00	13.00

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	DUKE UNIV MN DURHAM NC	DIST	100.00	44.00	
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	24.00	0.20	
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 STA 1 DURHAM NC	DIST	44.00	13.00	
9	DUKE UNIV STA 1 DURHAM NC	DIST	44.00	13.00	
10	DUKE UNIV STA 2 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 3 DURHAM NC	DIST	44.00	13.00	
14	DUKE UNIV STA 3 DURHAM NC	DIST	44.00	13.00	
15	DUKE UNIV STA 4 DURHAM NC	DIST	44.00	13.00	
16	DUKE UNIV STA 4 DURHAM NC	DIST	44.00	13.00	
17	DUKE UNIV STA 5 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	DUNBAR RET MOORESVILLE NC	DIST	100.00	13.00	
21	DUNBAR RET MOORESVILLE NC	DIST	100.00	13.00	
22	DUNCAN RET DUNCAN SC	DIST	44.00	13.00	
23	DUNCAN RET DUNCAN SC	DIST	44.00	13.00	
24	DURHAM MN DURHAM NC	DIST	100.00	13.00	
25	DURHAM MN DURHAM NC	DIST	100.00	13.00	
26	DURHAM MN DURHAM NC	DIST	100.00	13.00	
27	E BRYSON RET BRYSON CITY NC	DIST	66.00	13.00	
28	E CHESTER RET CHESTER SC	DIST	100.00	13.00	
29	E CHESTER RET CHESTER SC	DIST	100.00	13.00	
30	E DURHAM TIE DURHAM NC	TRANS	230.00	100.00	44.00
31	E DURHAM TIE DURHAM NC	TRANS	230.00	100.00	44.00
32	E DURHAM TIE DURHAM NC	TRANS	44.00	0.40	
33	E FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
34	E FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
35	E GANTT RET CONESTEE SC	DIST	44.00	13.00	
36	E GANTT RET CONESTEE SC	DIST	44.00	13.00	
37	E MAIDEN RET MAIDEN NC	DIST	44.00	6.90	
38	E MAIDEN RET MAIDEN NC	DIST	44.00	6.90	2.40
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) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	E MAIDEN RET MAIDEN NC	DIST	44.00	13.00	
2	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
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	6.90	2.40
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	44.00	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 SYLVA RET SYLVA NC	DIST	66.00	13.00	
13	E SYLVA RET SYLVA NC	DIST	66.00	13.00	
14	E THOMASVILLE RET THOMASVILLE NC	DIST	100.00	13.00	
15	E THOMASVILLE RET THOMASVILLE NC	DIST	100.00	13.00	
16	EASLEY CITY DEL 3 EASLEY SC	DIST	100.00	24.00	13.00
17	EASLEY CITY DEL 3 EASLEY SC	DIST	100.00	44.00	24.00
18	EASLEY CITY DEL 4 EASLEY SC	DIST	100.00	13.00	
19	EASLEY MN EASLEY SC	TRANS	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	44.00	
23	EASLEY MN EASLEY SC	TRANS	100.00	44.00	
24	EASTATOE RET PICKENS SC	DIST	100.00	13.00	
25	EASTFIELD RD RET CONCORD NC	DIST	100.00	13.00	
26	EASTFIELD RD RET CONCORD NC	DIST	100.00	24.00	
27	EASTGATE RET CHAPEL HILL NC	DIST	100.00	13.00	
28	EASTGATE RET CHAPEL HILL NC	DIST	100.00	13.00	
29	EASTOVER RET GREENVILLE SC	DIST	100.00	13.00	
30	EASTOVER RET GREENVILLE SC	DIST	100.00	13.00	
31	EASY ST RET CONCORD NC	DIST	44.00	13.00	
32	EBENEZER RET TRAVELERS REST SC	DIST	100.00	13.00	
33	EBERT RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
34	EDNEYVILLE RET HENDERSONVILLE NC	DIST	44.00	13.00	
35	EDNEYVILLE RET HENDERSONVILLE NC	DIST	44.00	13.00	
36	EFLAND RET EFLAND NC	DIST	44.00	13.00	
37	EFLAND RET EFLAND NC	DIST	44.00	13.00	
38	ELECTROLUX ANDERSON PL ANDERSON SC	DIST	44.00	13.00	
39	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	24.00	
40	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	24.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	24.00	
2	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	13.00	
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	24.00	4.10	2.40
6	ELIZABETH AVE RET CHARLOTTE NC	DIST	24.00	4.10	2.40
7	ELK VALLEY RET ELKIN NC	DIST	100.00	13.00	
8	ELK VALLEY RET ELKIN NC	DIST	100.00	13.00	
9	ELKIN RET ELKIN NC	DIST	44.00	2.40	
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	0.60
13	ELKIN RET ELKIN NC	DIST	44.00	6.90	2.40
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	ELLERBEE RET CHAPEL HILL NC	DIST	100.00	13.00	
18	ELLIOTT RET SHELBY NC	DIST	100.00	13.00	
19	ELLIOTT RET SHELBY NC	DIST	100.00	13.00	
20	ELLIS RD RET DURHAM NC	DIST	100.00	24.00	
21	ELLIS RD RET DURHAM NC	DIST	100.00	24.00	
22	ELMWOOD RET ELMWOOD NC	DIST	100.00	24.00	
23	EMERALD RD RET GREENWOOD SC	DIST	100.00	13.00	
24	ENERGYUNITED EMC DEL 11 TAYLORSVILLE NC	DIST	100.00	24.00	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	ENO RET DURHAM NC	DIST	44.00	24.00	
29	ENO RET DURHAM NC	DIST	44.00	24.00	13.00
30	ENO TIE DURHAM NC	TRANS	230.00	100.00	44.00
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	13.00
34	ENO TIE DURHAM NC	TRANS	44.00		
35	ENO TIE DURHAM NC	TRANS	44.00		
36	ENO TIE DURHAM NC	TRANS	44.00	0.40	
37	ENO TIE DURHAM NC	TRANS	13.00	0.40	0.20
38	ENOCHVILLE RET KANNAPOLIS NC	DIST	100.00	13.00	
39	ENOCHVILLE RET KANNAPOLIS NC	DIST	100.00	13.00	
40	ENOLA RET SPARTANBURG SC	DIST	100.00	13.00	

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1	ENOLA RET SPARTANBURG SC	DIST	100.00	13.00	
2	FAIR GROVE RET THOMASVILLE NC	DIST	100.00	13.00	
3	FAIRFAX RD RET GREENSBORO NC	DIST	100.00	24.00	
4	FAIRFAX RD RET GREENSBORO NC	DIST	100.00	24.00	
5	FAIRFAX RD RET GREENSBORO NC	DIST	100.00	24.00	
6	FAIRNTOSH RET DURHAM NC	DIST	100.00	24.00	
7	FAIRNTOSH RET DURHAM NC	DIST	100.00	24.00	
8	FAIRPLAINS RET NORTH WILKESBORO NC	DIST	100.00	13.00	
9	FAIRPLAINS RET NORTH WILKESBORO NC	DIST	100.00	13.00	
10	FAIRVIEW TIE FOREST CITY NC	TRANS	100.00	44.00	
11	FAIRVIEW TIE FOREST CITY NC	TRANS	100.00	44.00	
12	FAIRVIEW TIE FOREST CITY NC	TRANS	100.00	44.00	
13	FAITH RET SALISBURY NC	DIST	100.00	13.00	
14	FAITH RET SALISBURY NC	DIST	100.00	13.00	
15	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	2.40
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	
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	2.40
22	FANTS GROVE RET PENDLETON SC	DIST	44.00	13.00	
23	FANTS GROVE RET PENDLETON SC	DIST	44.00	24.00	
24	FANTS GROVE RET PENDLETON SC	DIST	44.00	24.00	
25	FIDDLERS CREEK RET WINSTON-SALEM NC	DIST	100.00	13.00	
26	FIDDLERS CREEK RET WINSTON-SALEM NC	DIST	100.00	13.00	
27	FINGERVILLE RET FINGERVILLE SC	DIST	100.00	13.00	
28	FIRST ST RET HICKORY NC	DIST	44.00	13.00	4.10
29	FIRST ST RET HICKORY NC	DIST	44.00	13.00	4.10
30	FIRST ST RET HICKORY NC	DIST	44.00	6.90	2.40
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	FISHER SS CHARLOTTE NC	DIST	100.00	24.00	
35	FISHER SS CHARLOTTE NC	DIST	100.00	24.00	
36	FISHER SS CHARLOTTE NC	DIST	24.00	4.10	
37	FISHER SS CHARLOTTE NC	DIST	24.00	4.10	
38	FISHING CREEK HYDRO GREAT FALLS SC	TRANS	100.00	6.90	
39	FISHING CREEK HYDRO GREAT FALLS SC	TRANS	100.00	6.90	
40	FLAT ROCK RET ANDERSON SC	DIST	44.00	13.00	

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1	FLAT ROCK RET ANDERSON SC	DIST	44.00	13.00	
2	FLAT ROCK RET ANDERSON SC	DIST	44.00	13.00	
3	FLAY RET LINCOLNTON NC	DIST	44.00	6.90	2.40
4	FLAY RET LINCOLNTON NC	DIST	44.00	6.90	2.40
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	FLORIDA AVE RET GREENWOOD SC	DIST	44.00	6.90	2.40
8	FLORIDA AVE RET GREENWOOD SC	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	13.00	
11	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
12	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
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 3 FOREST CITY NC	DIST	44.00	13.00	
19	FOREST CITY DEL 3 FOREST CITY NC	DIST	44.00	13.00	
20	FOREST HILL RET GREENWOOD SC	DIST	44.00	13.00	
21	FOREST HILL RET GREENWOOD SC	DIST	44.00	13.00	
22	FOREST LAKE RET FORT MILL SC	DIST	44.00	24.00	
23	FOUR SEASONS RET CHARLOTTE NC	DIST	100.00	24.00	
24	FOUR SEASONS RET CHARLOTTE NC	DIST	100.00	24.00	
25	FRIEDEN RET GIBSONVILLE NC	DIST	100.00	24.00	
26	FRIEDEN RET GIBSONVILLE NC	DIST	100.00	24.00	
27	FRIENDSHIP RET GREENSBORO NC	DIST	100.00	24.00	
28	FRIENDSHIP RET GREENSBORO NC	DIST	100.00	24.00	
29	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
30	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
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	FURR RD RET HUNTERSVILLE NC	DIST	44.00	13.00	
36	GAFFNEY CITY DEL 1A & 1B GAFFNEY SC	DIST	100.00	24.00	
37	GAFFNEY CITY DEL 1A & 1B GAFFNEY SC	DIST	100.00	24.00	
38	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
39	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
40	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	

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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	44.00	0.20	
6	GAFFNEY TIE GAFFNEY SC	TRANS	44.00	0.20	
7	GARRETT RD RET DURHAM NC	DIST	100.00	24.00	
8	GARRETT RD RET DURHAM NC	DIST	100.00	24.00	
9	GASTONIA CITY DEL 10 GASTONIA NC	DIST	100.00	13.00	
10	GASTONIA CITY DEL 10 GASTONIA NC	DIST	100.00	13.00	
11	GASTONIA CITY DEL 10 GASTONIA NC	DIST			
12	GASTONIA CITY DEL 11 GASTONIA NC	DIST	100.00	13.00	
13	GASTONIA CITY DEL 11 GASTONIA NC	DIST	100.00	13.00	
14	GASTONIA CITY DEL 12 GASTONIA NC	DIST	100.00	13.00	
15	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	
16	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	2.40
17	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	2.40
18	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	2.40
19	GASTONIA CITY DEL 6 GASTONIA NC	DIST	100.00	13.00	
20	GASTONIA CITY DEL 6 GASTONIA NC	DIST	100.00	13.00	
21	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	6.90	2.40
22	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	6.90	2.40
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	13.00	6.90
26	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	13.00	6.90
27	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	13.00	6.90
28	GASTONIA CITY DEL 9 GASTONIA NC	DIST	100.00	13.00	
29	GASTONIA CITY DEL 9 GASTONIA NC	DIST	100.00	13.00	
30	GATEWAY RET WHITTIER NC	DIST	66.00	13.00	
31	GATEWAY RET WHITTIER NC	DIST	66.00		
32	GATEWOOD RET GATEWOOD NC	DIST	44.00	13.00	
33	GENELEE RET DURHAM NC	DIST	100.00	24.00	
34	GENELEE RET DURHAM NC	DIST	100.00	24.00	
35	GILBREATH RET GRAHAM NC	DIST	100.00	24.00	
36	GILBREATH RET GRAHAM NC	DIST	100.00	24.00	
37	GILBREATH RET GRAHAM NC	DIST	24.00	13.00	
38	GILBREATH RET GRAHAM NC	DIST	24.00	13.00	
39	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	13.00	
40	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	6.90	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	6.90	
2	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	6.90	
3	GLEN RAVEN MN GLEN RAVEN NC	TRANS	100.00	24.00	
4	GLEN RAVEN MN GLEN RAVEN NC	TRANS	100.00	24.00	
5	GLEN RAVEN MN GLEN RAVEN NC	TRANS	100.00	24.00	
6	GLENOLA RET GLENOLA NC	DIST	100.00	13.00	
7	GLENOLA RET GLENOLA NC	DIST	100.00	13.00	
8	GLENWAY SS STATESVILLE NC	DIST	100.00	24.00	
9	GLENWOOD RET MARION NC	DIST	100.00	13.00	
10	GLENWOOD RET MARION NC	DIST	100.00	13.00	
11	GOODWILL CHURCH RD RET BELEWS CREEK NC	DIST	100.00	13.00	
12	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	13.00	
13	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	13.00	
14	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	24.00	
15	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	24.00	
16	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	24.00	
17	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
18	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
19	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
20	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
21	GRANITE FALLS CITY DEL 2 GRANITE FALLS NC	DIST	44.00	13.00	
22	GRASSY POND RET GRASSY POND SC	DIST	44.00	13.00	
23	GRASSY POND RET GRASSY POND SC	DIST	44.00	13.00	
24	GREAT FALLS HYDRO STA GREAT FALLS SC	TRANS	44.00	2.40	
25	GREAT FALLS HYDRO STA GREAT FALLS SC	TRANS	44.00	2.40	
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 SW STA GREAT FALLS SC	TRANS	100.00	44.00	
29	GREAT FALLS SW STA GREAT FALLS SC	TRANS	100.00	44.00	
30	GREEN POND RET ANDERSON SC	DIST	44.00	13.00	
31	GREEN POND RET ANDERSON SC	DIST	44.00	13.00	
32	GREEN ST RET DURHAM NC	DIST	100.00	13.00	
33	GREEN ST RET DURHAM NC	DIST	100.00	13.00	
34	GREENBRIAR SW STA SIMPSONVILLE SC	DIST	100.00	13.00	
35	GREENBRIAR SW STA SIMPSONVILLE SC	DIST	100.00	13.00	
36	GREENBRIAR SW STA SIMPSONVILLE SC	DIST	100.00	13.00	
37	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40
38	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40
39	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40
40	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
2	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
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	GREENVILLE MN GREENVILLE SC	TRANS	100.00	13.00	
7	GREENVILLE MN GREENVILLE SC	TRANS	100.00	13.00	
8	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
9	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
10	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
11	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	24.00
12	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
13	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
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	24.00	0.20	
19	GREENWOOD CITY DEL 1 GREENWOOD SC	DIST	44.00	13.00	
20	GREENWOOD CITY DEL 1 GREENWOOD SC	DIST	44.00	13.00	
21	GREENWOOD CITY DEL 3 GREENWOOD SC	DIST	44.00	13.00	
22	GREENWOOD CITY DEL 4 GREENWOOD SC	DIST	44.00	13.00	
23	GREENWOOD CITY DEL 4 GREENWOOD SC	DIST	44.00	13.00	
24	GREENWOOD CITY DEL 5 GREENWOOD SC	DIST	44.00	13.00	
25	GREENWOOD TIE GREENWOOD SC	TRANS	100.00	44.00	
26	GREENWOOD TIE GREENWOOD SC	TRANS	100.00	44.00	
27	GREENWOOD TIE GREENWOOD SC	TRANS	100.00	44.00	
28	GREENWOOD TIE GREENWOOD SC	TRANS	24.00	0.20	
29	GREER CITY STA 2 GREER SC	DIST	100.00	13.00	4.10
30	GREER CITY STA 2 GREER SC	DIST	100.00	13.00	4.10
31	GREER RET GREER SC	DIST	100.00	13.00	
32	GREY RET CHAPEL HILL NC	DIST	100.00	13.00	
33	GREY RET CHAPEL HILL NC	DIST	100.00	13.00	
34	GRIFFITH RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
35	GRIFFITH RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
36	GROOMTOWN RET GREENSBORO NC	DIST	100.00	24.00	
37	GROOMTOWN RET GREENSBORO NC	DIST	100.00	24.00	
38	GROOMTOWN RET GREENSBORO NC	DIST	100.00	13.00	
39	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
40	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	

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SUBSTATIONS

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1	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
2	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
3	GUTHRIE RET WINSTON-SALEM NC	DIST	100.00	13.00	
4	GUTHRIE RET WINSTON-SALEM NC	DIST	100.00	13.00	
5	HAMPTON AVE RET SPARTANBURG SC	DIST	100.00	13.00	
6	HAMPTON AVE RET SPARTANBURG SC	DIST	100.00	13.00	
7	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
8	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
9	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
10	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
11	HARRISBURG TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
12	HARRISBURG TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
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	44.00		
16	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	0.60	
17	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	0.60	
18	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	0.60	
19	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	2.40	0.60
20	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	2.40	0.60
21	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	2.40	0.60
22	HARTFORD AVE RET BESSEMER CITY NC	DIST	44.00	13.00	
23	HARTFORD AVE RET BESSEMER CITY NC	DIST	44.00	13.00	
24	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
25	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
26	HAW RIVER RET HAW RIVER NC	DIST	44.00	13.00	
27	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
28	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
29	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	24.00	
30	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	24.00	
31	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
32	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
33	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
34	HAYS RET HAYS NC	DIST	44.00	13.00	
35	HEATH RET RANDLEMAN NC	DIST	100.00	13.00	
36	HEATH RET RANDLEMAN NC	DIST	100.00	13.00	
37	HENDERSONVILLE TIE EAST FLAT ROCK NC	TRANS	100.00	44.00	
38	HENDERSONVILLE TIE EAST FLAT ROCK NC	TRANS	100.00	44.00	
39	HENDERSONVILLE TIE EAST FLAT ROCK NC	TRANS	24.00	0.20	
40	HENSLEY RD RET FORT MILL SC	DIST	13.00	2.40	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HENSLEY RD RET FORT MILL SC	DIST	13.00	2.40	
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	44.00	6.90	
5	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
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	HICKORY GROVE RET CHARLOTTE NC	DIST	100.00	13.00	
12	HICKORY GROVE RET CHARLOTTE NC	DIST	100.00	13.00	
13	HICKORY GROVE RET CHARLOTTE NC	DIST	100.00	13.00	
14	HICKORY TIE HICKORY NC	TRANS	100.00	44.00	
15	HICKORY TIE HICKORY NC	TRANS	100.00	44.00	
16	HICKORY TIE HICKORY NC	TRANS	100.00	44.00	
17	HICKORY TIE HICKORY NC	TRANS	24.00	0.20	
18	HIDDENITE RET HIDDENITE NC	DIST	44.00	13.00	
19	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	
20	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	
21	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	2.40
22	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	2.40
23	HIGH SHOALS RET HIGH SHOALS NC	DIST	13.00	2.40	
24	HIGH SHOALS RET HIGH SHOALS NC	DIST	13.00	2.40	
25	HIGH SHOALS RET HIGH SHOALS NC	DIST	13.00	2.40	
26	HIGH SHOALS RET HIGH SHOALS NC	DIST	44.00	13.00	
27	HIGH SHOALS RET HIGH SHOALS NC	DIST	44.00	13.00	13.00
28	HIGHLANDS RET HIGHLANDS NC	DIST	66.00	13.00	
29	HIGHLANDS RET HIGHLANDS NC	DIST	66.00	13.00	
30	HIGHTOWER RET TAYLORS SC	DIST	100.00	13.00	
31	HIGHTOWER RET TAYLORS SC	DIST	100.00	13.00	
32	HILL ST RET CHARLOTTE NC	DIST	100.00	24.00	
33	HILL ST RET CHARLOTTE NC	DIST	100.00	24.00	
34	HILL ST RET CHARLOTTE NC	DIST	100.00	24.00	
35	HILLBROOK RET SPARTANBURG SC	DIST	100.00	13.00	
36	HILLBROOK RET SPARTANBURG SC	DIST	100.00	13.00	
37	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
38	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
39	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
40	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	

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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	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
3	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	100.00	44.00	
4	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	100.00	44.00	
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	24.00	0.20	
8	HINSHAW RET WINSTON-SALEM NC	DIST	100.00	13.00	
9	HINSHAW RET WINSTON-SALEM NC	DIST	100.00	13.00	
10	HINSHAW RET WINSTON-SALEM NC	DIST	100.00	13.00	
11	HITACHI METALS LTD CHINA GROVE NC	DIST	44.00	13.00	
12	HODGES TIE HODGES SC	TRANS	230.00	100.00	44.00
13	HODGES TIE HODGES SC	TRANS	230.00	100.00	44.00
14	HODGES TIE HODGES SC	TRANS	44.00		
15	HODGES TIE HODGES SC	TRANS	44.00	0.40	
16	HOLCOMBE RD RET PIEDMONT SC	DIST	100.00	13.00	
17	HOLLY HILL RET THOMASVILLE NC	DIST	100.00	13.00	
18	HOLLY HILL RET THOMASVILLE NC	DIST	100.00	13.00	
19	HOMESTEAD RET CHAPEL HILL NC	DIST	100.00	13.00	
20	HOMESTEAD RET CHAPEL HILL NC	DIST	100.00	13.00	
21	HOPE VALLEY RET DURHAM NC	DIST	100.00	13.00	
22	HOPE VALLEY RET DURHAM NC	DIST	100.00	13.00	
23	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	
24	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	2.40
25	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	2.40
26	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	2.40
27	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	100.00	13.00
28	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	100.00	13.00
29	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	44.00	
30	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	44.00	
31	HORSESHOE TIE HENDERSONVILLE NC	TRANS	24.00	0.20	
32	HORSESHOE TIE HENDERSONVILLE NC	TRANS	24.00	0.20	
33	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	44.00	
34	HORSESHOE TIE HENDERSONVILLE NC	TRANS	24.00	0.20	
35	HORTON RD RET DURHAM NC	DIST	100.00	13.00	
36	HORTON RD RET DURHAM NC	DIST	100.00	13.00	
37	HUDLOW RET RUTHERFORDTON NC	DIST	100.00	13.00	
38	HUDSON ST RET GREENVILLE SC	DIST	100.00	13.00	
39	HUDSON ST RET GREENVILLE SC	DIST	100.00	13.00	
40	HUDSON ST RET GREENVILLE SC	DIST	100.00	13.00	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	HUNTERSVILLE CITY HUNTERSVILLE NC	DIST	44.00	13.00	
2	HUNTERSVILLE CITY HUNTERSVILLE NC	DIST	44.00	13.00	
3	HURRICANE CREEK RET ANDERSON SC	DIST	100.00	13.00	
4	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	13.00	
5	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	13.00	
6	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	24.00	
7	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	24.00	
8	ICARD RET ICARD NC	DIST	44.00	6.90	
9	ICARD RET ICARD NC	DIST	44.00	6.90	
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	IMPERIAL RET DURHAM NC	DIST	100.00	24.00	
16	IMPERIAL RET DURHAM NC	DIST	100.00	24.00	
17	IMPERIAL RET DURHAM NC	DIST	100.00	24.00	
18	INDIAN LAND RET FORT MILL SC	DIST	100.00	13.00	
19	INDIAN LAND RET FORT MILL SC	DIST	100.00	24.00	
20	INMAN TIE INMAN SC	TRANS	100.00	44.00	
21	INMAN TIE INMAN SC	TRANS	100.00	44.00	
22	INMAN TIE INMAN SC	TRANS	100.00	44.00	
23	ISLAND FORD RD RET STATESVILLE NC	DIST	100.00	13.00	
24	JAMES ST RET CHAPEL HILL NC	DIST	100.00	13.00	6.90
25	JAMES ST RET CHAPEL HILL NC	DIST	100.00	13.00	
26	JENKINS BRANCH RET BRYSON CITY NC	DIST	66.00	13.00	
27	JENKINS BRANCH RET BRYSON CITY NC	DIST	66.00	13.00	
28	JESSUPTOWN RET GREENSBORO NC	DIST	100.00	24.00	
29	JESSUPTOWN RET GREENSBORO NC	DIST	100.00	24.00	
30	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
31	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
32	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
33	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
34	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
35	JOCASSEE HYDRO JOCASSEE SC	TRANS	4.10	0.60	
36	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
37	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
38	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
39	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
40	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	JOCASSEE HYDRO JOCASSEE SC	TRANS	4.10	0.60	
2	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
3	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
4	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.60	
5	JOCASSEE TIE JOCASSEE SC	TRANS	500.00	230.00	24.00
6	JOCASSEE TIE JOCASSEE SC	TRANS	500.00	230.00	24.00
7	JOCASSEE TIE JOCASSEE SC	TRANS	500.00	230.00	24.00
8	JOCASSEE TIE JOCASSEE SC	TRANS	230.00	13.00	13.00
9	JOHNS CREEK RET GREENWOOD SC	DIST	100.00	13.00	
10	JOHNS CREEK RET GREENWOOD SC	DIST	100.00	13.00	
11	JULIAN RD RET SALISBURY NC	DIST	100.00	13.00	
12	KANUGA RET HENDERSONVILLE NC	DIST	44.00	13.00	
13	KANUGA RET HENDERSONVILLE NC	DIST	44.00	13.00	
14	KENILWORTH RET CHARLOTTE NC	DIST	100.00	13.00	
15	KENILWORTH RET CHARLOTTE NC	DIST	100.00	13.00	
16	KENILWORTH RET CHARLOTTE NC	DIST	100.00	13.00	
17	KEOWEE HYDRO NEWRY SC	TRANS	230.00	13.00	13.00
18	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.20	
19	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.20	
20	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.60	
21	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.20	
22	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.60	
23	KEOWEE HYDRO NEWRY SC	TRANS	4.10	0.60	
24	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
25	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	44.00	13.00
26	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	44.00	13.00
27	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	44.00	13.00
28	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
29	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
30	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
31	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	24.00	13.00
32	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
33	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
34	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
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	KEY ST RET PILOT MOUNTAIN NC	DIST	44.00	13.00	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	KEY ST RET PILOT MOUNTAIN NC	DIST	44.00	13.00	
2	KILDARE RET GREENSBORO NC	DIST	100.00	24.00	
3	KILDARE RET GREENSBORO NC	DIST	100.00	24.00	
4	KIMESVILLE RET KIMESVILLE NC	DIST	44.00	13.00	
5	KIMESVILLE RET KIMESVILLE NC	DIST	44.00	13.00	
6	KINCAID RD RET HUDSON NC	DIST	100.00	13.00	
7	KINCAID RD RET HUDSON NC	DIST	100.00	13.00	
8	KING RET KING NC	DIST	100.00	13.00	
9	KING RET KING NC	DIST	100.00	13.00	
10	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
11	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
12	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
13	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
14	KINGS MTN MAIN KINGS MOUNTAIN NC	DIST	44.00	13.00	
15	KINGS MTN MAIN KINGS MOUNTAIN NC	DIST	44.00	13.00	
16	KINGSGATE RET GREENVILLE SC	DIST	100.00	13.00	
17	KIT CREEK RET DURHAM NC	DIST	100.00	24.00	
18	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
19	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
20	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
21	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
22	KIVETT DR RET HIGH POINT NC	DIST	24.00	13.00	13.00
23	KIVETT DR RET HIGH POINT NC	DIST	24.00	13.00	13.00
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	KNIGHTS RET ROCK HILL SC	DIST	100.00	24.00	
27	KNOLLWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
28	KNOLLWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
29	KUDZU RET CHARLOTTE NC	DIST	100.00	24.00	
30	KUDZU RET CHARLOTTE NC	DIST	100.00	13.00	
31	LAKE EMORY TIE FRANKLIN NC	TRANS	161.00	66.00	
32	LAKE EMORY TIE FRANKLIN NC	TRANS	161.00	66.00	
33	LAKE EMORY TIE FRANKLIN NC	TRANS	161.00	66.00	
34	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	0.60
35	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	0.60
36	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	0.60
37	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	
38	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	
39	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	
40	LAKE EMORY TIE FRANKLIN NC	TRANS	66.00	2.40	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LAKE LURE RET LAKE LURE NC	DIST	44.00	6.90	2.40
2	LAKE LURE RET LAKE LURE NC	DIST	44.00	6.90	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	13.00	
6	LAKE TOWNSEND RET GREENSBORO NC	DIST	100.00	24.00	
7	LAKE TOWNSEND RET GREENSBORO NC	DIST	100.00	24.00	
8	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	6.90	
9	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	6.90	
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	13.00	6.90
13	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	13.00	6.90
14	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	13.00	6.90
15	LAKEWOOD RET CHARLOTTE NC	DIST	44.00	4.10	
16	LAKEWOOD RET CHARLOTTE NC	DIST	44.00	4.10	
17	LAKEWOOD TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
18	LAKEWOOD TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
19	LAKEWOOD TIE CHARLOTTE NC	TRANS	44.00		
20	LAKEWOOD TIE CHARLOTTE NC	TRANS	44.00		
21	LAKEWOOD TIE CHARLOTTE NC	TRANS	44.00	0.40	
22	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	
23	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	
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	24.00
27	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	24.00
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	24.00	0.20	
31	LANCASTER RET LANCASTER SC	DIST	100.00	2.40	
32	LANCASTER RET LANCASTER SC	DIST	100.00	2.40	
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	13.00	
36	LANCASTER RET LANCASTER SC	DIST	100.00	13.00	
37	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	2.40	
38	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	2.40	
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	

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1	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	13.00	
2	LANDO RET LANDO SC	DIST	44.00	13.00	
3	LANDO RET LANDO SC	DIST	44.00	13.00	
4	LANDRUM RET LANDRUM SC	DIST	44.00	13.00	
5	LANDRUM RET LANDRUM SC	DIST	44.00	6.90	
6	LANDRUM RET LANDRUM SC	DIST	44.00	6.90	
7	LANDRUM RET LANDRUM SC	DIST	44.00	6.90	
8	LANGSTON CREEK RET GREENVILLE SC	DIST	100.00	13.00	
9	LANGSTON CREEK RET GREENVILLE SC	DIST	100.00	13.00	
10	LANGTREE RET MOORESVILLE NC	DIST	100.00	13.00	
11	LAUREL CREEK RET GREENVILLE SC	DIST	100.00	13.00	
12	LAUREL CREEK RET GREENVILLE SC	DIST	100.00	13.00	
13	LAURENS CITY CAROLINE STA LAURENS SC	DIST	100.00	13.00	
14	LAURENS CITY CAROLINE STA LAURENS SC	DIST	100.00	13.00	
15	LAURENS E C DEL 10 LAURENS LAURENS SC	DIST	44.00	6.90	
16	LAURENS E C DEL 10 LAURENS LAURENS SC	DIST	44.00	6.90	2.40
17	LAURENS E C DEL 10 LAURENS LAURENS SC	DIST	44.00	6.90	2.40
18	LAURENS E C DEL 25 MAULDIN MAULDIN SC	DIST	100.00	13.00	4.10
19	LAURENS E C DEL 25 MAULDIN MAULDIN SC	DIST	100.00	13.00	
20	LAURENS E C DEL 26 WALNUT GROVE SC	DIST	100.00	13.00	
21	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
22	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
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	44.00	13.00	6.90
29	LAURENS TIE LAURENS SC	TRANS	44.00	13.00	6.90
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	LAWNDALE RET LAWNDALE NC	DIST	44.00	13.00	
33	LAWSONS FORK TIE SPARTANBURG SC	TRANS	100.00	44.00	
34	LAWSONS FORK TIE SPARTANBURG SC	TRANS	100.00	44.00	
35	LEAFCREST RET CHARLOTTE NC	DIST	100.00	13.00	
36	LEE STEAM STA COMB TURB PELZER SC	TRANS	100.00	13.00	
37	LEE STEAM STA COMB TURB PELZER SC	TRANS	100.00	13.00	
38	LELIA RET WELLFORD SC	DIST	100.00	12.50	
39	LELIA RET WELLFORD SC	DIST	100.00	13.00	
40	LESLIE RET LESLIE SC	DIST	44.00	6.90	2.40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LESLIE RET LESLIE SC	DIST	44.00	6.90	2.40
2	LESLIE RET LESLIE SC	DIST	44.00	6.90	2.40
3	LESLIE RET LESLIE SC	DIST	44.00	6.90	
4	LESLIE RET LESLIE SC	DIST	44.00	13.00	
5	LEWISVILLE RET LEWISVILLE NC	DIST	100.00	13.00	
6	LEWISVILLE RET LEWISVILLE NC	DIST	100.00	13.00	
7	LEXINGTON CITY DEL 1 LEXINGTON NC	DIST	100.00	44.00	
8	LEXINGTON CITY DEL 1 LEXINGTON NC	DIST	100.00	44.00	
9	LEXINGTON CITY DEL 1 LEXINGTON NC	DIST	24.00	0.20	
10	LEXINGTON MN LEXINGTON NC	DIST	100.00	24.00	
11	LEXINGTON MN LEXINGTON NC	DIST	100.00	24.00	
12	LEXINGTON MN LEXINGTON NC	DIST	100.00	13.00	6.90
13	LEXINGTON MN LEXINGTON NC	DIST	100.00	13.00	6.90
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	LIBERTY RET NEW LIBERTY SC	DIST	100.00	13.00	
17	LIBERTY RET NEW LIBERTY SC	DIST	100.00	13.00	
18	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
19	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	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	LINCOLNTON CITY LINCOLNTON NC	DIST	100.00	13.00	6.90
27	LINCOLNTON CITY LINCOLNTON NC	DIST	100.00	13.00	6.90
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 TIE LINCOLNTON NC	TRANS	100.00	13.00	
31	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	13.00	
32	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	44.00	
33	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	44.00	
34	LINDE LLC MIDLAND NC	TRANS	100.00	13.00	
35	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
36	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
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	24.00	13.00
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	13.00	6.90

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	6.90	
3	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	6.90	
4	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
5	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
6	LINWOOD SS LEXINGTON NC	DIST	100.00	44.00	24.00
7	LIONS MOUNTAIN TIE CALVERT NC	TRANS	100.00	44.00	
8	LIONS MOUNTAIN TIE CALVERT NC	TRANS	100.00	44.00	
9	LIONS MOUNTAIN TIE CALVERT NC	TRANS	44.00	4.10	2.40
10	LIONS MOUNTAIN TIE CALVERT NC	TRANS	44.00	0.20	
11	LITTLE ROCK RET CHARLOTTE NC	DIST	100.00	13.00	
12	LITTLE ROCK RET CHARLOTTE NC	DIST	100.00	13.00	
13	LITTLE ROCK RET CHARLOTTE NC	DIST	100.00	24.00	
14	LOCKHART POWER CO DEL 1 PACOLET SC	DIST	100.00	44.00	33.00
15	LOCKHART POWER CO DEL 1 PACOLET SC	DIST	100.00	44.00	33.00
16	LOCKHART POWER CO DEL 1 PACOLET SC	DIST	33.00		
17	LOCUST RET LOCUST NC	DIST	100.00	13.00	
18	LONG FERRY RET SALISBURY NC	DIST	100.00	13.00	
19	LONG FERRY RET SALISBURY NC	DIST	100.00	13.00	
20	LONGVIEW RET LONG VIEW NC	DIST	44.00	13.00	
21	LONGVIEW RET LONG VIEW NC	DIST	44.00	13.00	
22	LONGVIEW TIE LONG VIEW NC	TRANS	230.00	100.00	44.00
23	LONGVIEW TIE LONG VIEW NC	TRANS	230.00	100.00	44.00
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	44.00		
27	LONGVIEW TIE LONG VIEW NC	TRANS	44.00		
28	LONGVIEW TIE LONG VIEW NC	TRANS	44.00	6.90	2.40
29	LONGVIEW TIE LONG VIEW NC	TRANS	44.00	6.90	2.40
30	LONGVIEW TIE LONG VIEW NC	TRANS	44.00	6.90	2.40
31	LOOKOUT HYDRO STATESVILLE NC	TRANS	100.00	6.90	
32	LOOKOUT HYDRO STATESVILLE NC	TRANS	100.00	6.90	
33	LOOKOUT TIE STATESVILLE NC	TRANS	100.00	44.00	
34	LOOKOUT TIE STATESVILLE NC	TRANS	100.00	44.00	
35	LOOKOUT TIE STATESVILLE NC	TRANS	100.00	44.00	
36	LOOKOUT TIE STATESVILLE NC	TRANS	24.00	0.20	
37	LUMBER LANE RET MOUNT HOLLY NC	DIST	100.00	13.00	
38	LUNSFORD RD RET KING NC	DIST	100.00	13.00	
39	MACEDONIA RET TAYLORSVILLE NC	DIST	100.00	13.00	
40	MADISON RET MADISON NC	DIST	100.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MADISON RET MADISON NC	DIST	100.00	13.00	
2	MADISON TIE MADISON NC	TRANS	100.00	44.00	
3	MADISON TIE MADISON NC	TRANS	100.00	44.00	
4	MADISON TIE MADISON NC	TRANS	100.00	44.00	
5	MAIDEN CITY DEL 2 MAIDEN NC	DIST	44.00	13.00	
6	MAIDEN CITY DEL 2 MAIDEN NC	DIST	44.00	13.00	
7	MAJOLICA RD RET SALISBURY NC	DIST	100.00	13.00	
8	MALLARD CREEK RET CHARLOTTE NC	DIST	100.00	13.00	
9	MALLARD CREEK RET CHARLOTTE NC	DIST	100.00	13.00	
10	MANCHESTER RET KANNAPOLIS NC	DIST	100.00	13.00	
11	MARBLE TIE MARBLE NC	TRANS	161.00	34.50	
12	MARBLE TIE MARBLE NC	TRANS	161.00	34.50	
13	MARBLE TIE MARBLE NC	TRANS	34.50	13.00	
14	MARBLE TIE MARBLE NC	TRANS	13.00	0.40	
15	MARBLE TIE MARBLE NC	TRANS	13.00	0.40	
16	MARBLE TIE MARBLE NC	TRANS	13.00	0.40	
17	MAR-DON DR RET WINSTON-SALEM NC	DIST	100.00	13.00	
18	MAR-DON DR RET WINSTON-SALEM NC	DIST	100.00	24.00	
19	MARIETTA TIE MARIETTA SC	TRANS	100.00	44.00	
20	MARIETTA TIE MARIETTA SC	TRANS	100.00	44.00	
21	MARIETTA TIE MARIETTA SC	TRANS	24.00	0.20	
22	MARION MN MARION NC	DIST	100.00	13.00	6.90
23	MARION MN MARION NC	DIST	100.00	13.00	6.90
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	44.00	6.90	2.40
27	MARION MN MARION NC	DIST	44.00	6.90	2.40
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	MARKET POINT RET GREENVILLE SC	DIST	100.00	13.00	
31	MARSHALL RET TERRELL NC	DIST	44.00	13.00	
32	MARSHALL STEAM STA YARD TERRELL NC	TRANS	230.00	24.00	
33	MARSHALL STEAM STA YARD TERRELL NC	TRANS	230.00	24.00	
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	4.10	0.60	
37	MARSHALL STEAM STA YARD TERRELL NC	TRANS	4.10	0.60	
38	MARSHALL STEAM STA YARD TERRELL NC	TRANS			
39	MARSHALL STEAM STA YARD TERRELL NC	TRANS			
40	MASCOT RET INMAN SC	DIST	44.00	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	MASCOT RET INMAN SC	DIST	44.00	13.00	
2	MATTHEWS RET CHARLOTTE NC	DIST	100.00	24.00	
3	MATTHEWS RET CHARLOTTE NC	DIST	100.00	24.00	
4	MATTHEWS RET CHARLOTTE NC	DIST	100.00	24.00	
5	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	100.00	44.00	
6	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	100.00	44.00	
7	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	100.00	44.00	
8	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	44.00	13.00	
9	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	44.00	13.00	
10	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	24.00	0.20	
11	MCALPINE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
12	MCALPINE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
13	MCALPINE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
14	MCDOWELL TIE MARION NC	TRANS	230.00	100.00	44.00
15	MCDOWELL TIE MARION NC	TRANS	100.00	44.00	
16	MCDOWELL TIE MARION NC	TRANS	44.00	24.00	
17	MCDOWELL TIE MARION NC	TRANS	44.00	24.00	
18	MCDOWELL TIE MARION NC	TRANS	44.00	24.00	
19	MCDOWELL TIE MARION NC	TRANS	44.00	2.40	0.60
20	MCDOWELL TIE MARION NC	TRANS	44.00	2.40	0.60
21	MCDOWELL TIE MARION NC	TRANS	44.00	2.40	0.60
22	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	230.00	24.00	
23	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	24.00	6.90	6.90
24	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	24.00	6.90	6.90
25	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	4.10	
26	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	4.10	
27	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	24.00	13.00	
28	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	230.00	24.00	
29	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	4.10	0.60	
30	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	4.10	0.60	
31	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	4.10	0.60	
32	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	4.10	0.60	
33	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	4.10	0.60	
34	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	4.10	0.60	
35	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
36	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
37	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
38	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
39	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
40	MCGUIRE NUC STA UNIT 1 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
2	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
3	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
4	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
5	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
6	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
7	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
8	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
9	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	4.10	
10	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	4.10	
11	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
12	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
13	MCGUIRE NUC STA UNIT 1 HUNTERSVILLE NC	TRANS	6.90	0.60	
14	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	500.00	24.00	
15	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	24.00	6.90	6.90
16	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	24.00	6.90	6.90
17	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	4.10	
18	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	4.10	
19	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	24.00	13.00	
20	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	500.00	24.00	
21	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
22	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
23	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
24	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
25	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
26	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	4.10	0.60	
27	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
28	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
29	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
30	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
31	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
32	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
33	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
34	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
35	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
36	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
37	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	0.60	
38	MCGUIRE NUC STA UNIT 2 HUNTERSVILLE NC	TRANS	6.90	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	

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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 RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
2	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
3	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
4	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
5	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00	230.00	24.00
6	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00	230.00	24.00
7	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00	230.00	24.00
8	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00	230.00	24.00
9	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	6.90	4.10	
10	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	24.00	4.10	
11	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
12	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
13	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
14	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
15	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
16	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
17	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS			
18	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS			
19	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS			
20	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	4.10		
21	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
22	MEADOW GREEN RET EDEN NC	DIST	100.00	13.00	
23	MEADOW GREEN RET EDEN NC	DIST	100.00	13.00	
24	MEBANE RET MEBANE NC	DIST	44.00	2.40	
25	MEBANE RET MEBANE NC	DIST	44.00	2.40	
26	MEBANE RET MEBANE NC	DIST	44.00	2.40	
27	MEBANE RET MEBANE NC	DIST	44.00	2.40	
28	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
29	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
30	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
31	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
32	MEBANE RET MEBANE NC	DIST	44.00	13.00	
33	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
34	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
35	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
36	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
37	MEBANE TIE MEBANE NC	TRANS	24.00	0.20	
38	MERRITT DR RET GREENSBORO NC	DIST	100.00	24.00	
39	MERRITT DR RET GREENSBORO NC	DIST	100.00	24.00	
40	MIDWAY SS UNION SC	TRANS	100.00	33.00	

SUBSTATIONS

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1	MIDWAY SS UNION SC	TRANS	100.00	33.00	
2	MILLER HILL RET LENOIR NC	DIST	100.00	13.00	
3	MILLER HILL RET LENOIR NC	DIST	100.00	13.00	
4	MILLER HILL RET LENOIR NC	DIST	100.00	13.00	
5	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
6	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
7	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
8	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
9	MILLERS CREEK RET NORTH WILKESBORO NC	DIST	100.00	13.00	
10	MILLERS CREEK RET NORTH WILKESBORO NC	DIST	100.00	13.00	
11	MILLIS RET HIGH POINT NC	DIST	100.00	24.00	
12	MILLIS RET HIGH POINT NC	DIST	100.00	24.00	
13	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
14	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
15	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
16	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
17	MINE SHAFT RET CHARLOTTE NC	DIST	100.00	24.00	
18	MINE SHAFT RET CHARLOTTE NC	DIST	100.00	24.00	
19	MINE SHAFT RET CHARLOTTE NC	DIST	100.00	24.00	
20	MINI RANCH RET WAXHAW NC	DIST	100.00	24.00	
21	MITCHELL RIVER TIE ELKIN NC	TRANS	230.00	100.00	44.00
22	MITCHELL RIVER TIE ELKIN NC	TRANS	230.00	100.00	44.00
23	MITCHELL RIVER TIE ELKIN NC	TRANS	230.00	100.00	44.00
24	MITCHELL RIVER TIE ELKIN NC	TRANS	44.00		
25	MITCHELL RIVER TIE ELKIN NC	TRANS	44.00		
26	MITCHELL RIVER TIE ELKIN NC	TRANS	44.00	0.40	
27	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
28	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
29	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
30	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
31	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	44.00	
32	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	44.00	
33	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	44.00	
34	MOCKSVILLE MN MOCKSVILLE NC	TRANS	24.00	0.20	
35	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	24.00	
36	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	24.00	
37	MOCKSVILLE SOLAR	TRANS	44.00		
38	MONROE MN MONROE NC	TRANS	44.00	6.90	2.40
39	MONROE MN MONROE NC	TRANS	44.00	6.90	2.40
40	MONROE MN MONROE NC	TRANS	44.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
2	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
3	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
4	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
5	MONROE MN MONROE NC	TRANS	100.00	44.00	
6	MONROE MN MONROE NC	TRANS	100.00	44.00	
7	MONROE RD RET CHARLOTTE NC	DIST	100.00	13.00	
8	MONROE RD RET CHARLOTTE NC	DIST	100.00	13.00	
9	MONROE RD RET CHARLOTTE NC	DIST	100.00	13.00	
10	MONROETON RET MONROETON NC	DIST	44.00	13.00	
11	MONTCLAIRE RET CHARLOTTE NC	DIST	100.00	24.00	
12	MONTCLAIRE RET CHARLOTTE NC	DIST	100.00	24.00	
13	MONTICELLO RET GREENSBORO NC	DIST	44.00	13.00	
14	MONTROYAL RD RET RURAL HALL NC	DIST	100.00	13.00	
15	MOONVILLE RET GREENVILLE SC	DIST	100.00	13.00	
16	MOONVILLE RET GREENVILLE SC	DIST	100.00	13.00	
17	MOORE RET MOORE SC	DIST	44.00	13.00	
18	MOORESBORO RET MOORESBORO NC	DIST	44.00	13.00	
19	MOORESBORO RET MOORESBORO NC	DIST	44.00	13.00	
20	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
21	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
22	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
23	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
24	MOORESVILLE TIE MOORESVILLE NC	TRANS	24.00	0.20	
25	MORGANTON CITY DEL 3 MORGANTON NC	DIST	44.00	13.00	
26	MORGANTON CITY DEL 3 MORGANTON NC	DIST	44.00	13.00	
27	MORGANTON CITY DEL 4 MATS MORGANTON NC	DIST	100.00	13.00	
28	MORGANTON TIE MORGANTON NC	TRANS	100.00	24.00	13.00
29	MORGANTON TIE MORGANTON NC	TRANS	100.00	24.00	13.00
30	MORGANTON TIE MORGANTON NC	TRANS	100.00	24.00	13.00
31	MORGANTON TIE MORGANTON NC	TRANS	100.00	44.00	
32	MORGANTON TIE MORGANTON NC	TRANS	100.00	44.00	
33	MORGANTON TIE MORGANTON NC	TRANS	100.00	44.00	
34	MORGANTON TIE MORGANTON NC	TRANS			
35	MORGANTON TIE MORGANTON NC	TRANS			
36	MORNING STAR TIE MATTHEWS NC	TRANS	230.00	100.00	44.00
37	MORNING STAR TIE MATTHEWS NC	TRANS	230.00	100.00	44.00
38	MORNING STAR TIE MATTHEWS NC	TRANS	230.00	100.00	44.00
39	MORNING STAR TIE MATTHEWS NC	TRANS	100.00	24.00	
40	MORNING STAR TIE MATTHEWS NC	TRANS	100.00	24.00	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MORNING STAR TIE MATTHEWS NC	TRANS	44.00	0.40	
2	MOTLEY TIE EDEN NC	TRANS	100.00	44.00	
3	MOTLEY TIE EDEN NC	TRANS	100.00	44.00	
4	MOTLEY TIE EDEN NC	TRANS	24.00	0.20	
5	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
6	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
7	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
8	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
9	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
10	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
11	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
12	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
13	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
14	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
15	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
16	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
17	MT OLIVE RET CONOVER NC	DIST	44.00	13.00	
18	MT OLIVE RET CONOVER NC	DIST	44.00	13.00	
19	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
20	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
21	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
22	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
23	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
24	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
25	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	13.00	4.10
26	MT TABOR RET WINSTON-SALEM NC	DIST	100.00	13.00	
27	MT TABOR RET WINSTON-SALEM NC	DIST	100.00	13.00	
28	MTN VIEW RET HICKORY NC	DIST	100.00	13.00	
29	MTN VIEW RET HICKORY NC	DIST	100.00	13.00	
30	MUD CREEK RD RET BOILING SPRINGS SC	DIST	100.00	13.00	
31	MUD CREEK RD RET BOILING SPRINGS SC	DIST	100.00	13.00	
32	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
33	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
34	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
35	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
36	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
37	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
38	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
39	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
40	MURDOCK RD RET TROUTMAN NC	DIST	44.00	13.00	

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1	MURDOCK RD RET TROUTMAN NC	DIST	44.00	13.00	
2	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
3	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
4	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
5	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	13.00	6.90
6	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
7	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	13.00	6.90
8	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	13.00	6.90
9	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
10	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
11	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
12	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
13	N FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
14	N GORDONTON RET THOMASVILLE NC	DIST	100.00	13.00	
15	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	13.00
16	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	44.00
17	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	13.00
18	N GREENSBORO TIE GREENSBORO NC	TRANS	100.00	44.00	
19	N GREENSBORO TIE GREENSBORO NC	TRANS	44.00		
20	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	44.00
21	N GREENSBORO TIE GREENSBORO NC	TRANS	44.00	0.40	
22	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
23	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
24	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
25	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
26	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00		
27	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00		
28	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00	2.40	0.60
29	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00	2.40	0.60
30	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00	2.40	0.60
31	N GREENWOOD RET GREENWOOD SC	DIST	44.00	13.00	
32	N GREENWOOD RET GREENWOOD SC	DIST	44.00	13.00	
33	N HICKORY RET HICKORY NC	DIST	100.00	13.00	
34	N HICKORY RET HICKORY NC	DIST	100.00	13.00	
35	N STANLEY RET STANLEY NC	DIST	100.00	13.00	4.10
36	N STANLEY RET STANLEY NC	DIST	100.00	13.00	
37	N WINSTON RET WINSTON-SALEM NC	DIST	100.00	13.00	
38	N WINSTON RET WINSTON-SALEM NC	DIST	100.00	13.00	
39	N WINSTON RET WINSTON-SALEM NC	DIST	100.00	13.00	
40	NANTAHALA HYDRO TOPTON NC	TRANS	161.00	13.00	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	NANTAHALA HYDRO TOPTON NC	TRANS	161.00	13.00	
2	NANTAHALA HYDRO TOPTON NC	TRANS	161.00	34.50	
3	NANTAHALA HYDRO TOPTON NC	TRANS	13.00	0.40	
4	NANTAHALA HYDRO TOPTON NC	TRANS	13.00	0.40	
5	NANTAHALA HYDRO TOPTON NC	TRANS	34.50	13.00	
6	NAPLES RET NAPLES NC	DIST	44.00	13.00	
7	NAPLES RET NAPLES NC	DIST	44.00	13.00	
8	NEALS CREEK RET ANDERSON SC	DIST	44.00	13.00	
9	NEALS CREEK RET ANDERSON SC	DIST	44.00	13.00	
10	NEBO RET MARION NC	DIST	100.00	13.00	
11	NELSON RET DURHAM NC	DIST	100.00	24.00	
12	NELSON RET DURHAM NC	DIST	100.00	24.00	
13	NEW CUT RD RET INMAN SC	DIST	100.00	13.00	
14	NEW HOPE RET GASTONIA NC	DIST	100.00	13.00	
15	NEW HOPE RET GASTONIA NC	DIST	100.00	13.00	
16	NEWBERRY MN NEWBERRY SC	TRANS	100.00	24.00	
17	NEWBERRY MN NEWBERRY SC	TRANS	100.00	24.00	
18	NEWELL RET CHARLOTTE NC	DIST	100.00	24.00	
19	NEWELL RET CHARLOTTE NC	DIST	100.00	24.00	
20	NEWPORT RET NEWPORT SC	DIST	44.00	13.00	
21	NEWPORT RET NEWPORT SC	DIST	44.00	13.00	
22	NEWPORT TIE NEWPORT SC	TRANS	230.00	100.00	44.00
23	NEWPORT TIE NEWPORT SC	TRANS	230.00	100.00	44.00
24	NEWPORT TIE NEWPORT SC	TRANS	230.00	100.00	44.00
25	NEWPORT TIE NEWPORT SC	TRANS	44.00	0.40	
26	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
27	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
28	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
29	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
30	NEWPORT TIE NEWPORT SC	TRANS	44.00		
31	NEWPORT TIE NEWPORT SC	TRANS	500.00		
32	NEWPORT TIE NEWPORT SC	TRANS	500.00		
33	NEWPORT TIE NEWPORT SC	TRANS	500.00		
34	NEWTON CITY DEL 2 NEWTON NC	DIST	100.00	13.00	6.90
35	NEWTON CITY DEL 2 NEWTON NC	DIST	100.00	13.00	6.90
36	NEWTON CITY DEL 2 NEWTON NC	DIST	100.00	13.00	6.90
37	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
38	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
39	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
40	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	

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1	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
2	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
3	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
4	NEWTON TIE NEWTON NC	TRANS	24.00	0.20	
5	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
6	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
7	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
8	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
9	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
10	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
11	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
12	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
13	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
14	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
15	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	24.00	0.20	
16	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	24.00	0.20	
17	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	24.00	0.20	
18	NIX RD RET HENDERSONVILLE NC	DIST	100.00	13.00	
19	NORRIS RET CATEECHEE SC	DIST	44.00	13.00	
20	NORRIS RET CATEECHEE SC	DIST	44.00	13.00	
21	NORTH DENVER RET DENVER NC	DIST	100.00	13.00	
22	NORTH LAKES RET HICKORY NC	DIST	100.00	13.00	
23	NORTH LINCOLN RET LINCOLNTON NC	DIST	44.00	13.00	
24	NORTH ST RET ANDERSON SC	DIST	44.00	13.00	
25	OAK RIDGE RET KERNERSVILLE NC	DIST	100.00	13.00	
26	OAK RIDGE RET KERNERSVILLE NC	DIST	100.00	13.00	
27	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
28	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
29	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
30	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
31	OAKBORO TIE OAKBORO NC	TRANS	230.00	100.00	44.00
32	OAKBORO TIE OAKBORO NC	TRANS	230.00	100.00	44.00
33	OAKBORO TIE OAKBORO NC	TRANS	230.00	100.00	44.00
34	OAKBORO TIE OAKBORO NC	TRANS	44.00		
35	OAKBORO TIE OAKBORO NC	TRANS	44.00	0.40	
36	OAKLAND RD RET SPINDALE NC	DIST	100.00	13.00	
37	OAKLAND RD RET SPINDALE NC	DIST	100.00	13.00	
38	OAKVALE TIE GREENVILLE SC	TRANS	100.00	24.00	
39	OAKVALE TIE GREENVILLE SC	TRANS	100.00	24.00	
40	OAKVALE TIE GREENVILLE SC	TRANS	100.00	24.00	

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1	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
2	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
3	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
4	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	24.00
5	OAKVALE TIE GREENVILLE SC	TRANS	100.00	13.00	
6	OAKVALE TIE GREENVILLE SC	TRANS	100.00	13.00	
7	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
8	OAKWOOD ST RET MEBANE NC	DIST	100.00	13.00	
9	OAKWOOD ST RET MEBANE NC	DIST	100.00	13.00	
10	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	230.00	4.10	
11	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	24.00	4.10	
12	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
13	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
14	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
15	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
16	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
17	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
18	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
19	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
20	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
21	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
22	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
23	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00		
24	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
25	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
26	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	230.00	24.00	
27	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	24.00	6.90	4.10
28	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
29	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
30	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
31	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
32	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
33	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
34	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
35	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
36	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
37	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
38	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
39	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	230.00	6.90	4.10
40	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	230.00	6.90	4.10

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1	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
2	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
3	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	230.00	24.00	
4	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	24.00	6.90	4.10
5	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
6	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
7	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
8	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
9	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
10	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
11	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
12	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
13	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
14	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
15	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	230.00	6.90	4.10
16	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
17	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
18	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
19	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
20	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	24.00	6.90	4.10
21	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
22	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
23	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
24	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
25	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
26	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
27	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
28	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
29	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
30	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	230.00	6.90	4.10
31	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	13.00	4.10	
32	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	13.00	4.10	
33	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	100.00	4.10	4.10
34	OCONEE SITE 100KV NEWRY SC	TRANS	100.00	24.00	
35	OCONEE SITE 100KV NEWRY SC	TRANS	100.00	24.00	
36	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
37	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
38	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
39	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
40	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
2	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
3	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
4	OLD FORT RET OLD FORT NC	DIST	44.00	13.00	
5	ONEAL RET GREER SC	DIST	100.00	13.00	
6	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
7	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
8	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
9	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
10	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	
11	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	
12	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	
13	OTTO RET OTTO NC	DIST	69.00	13.00	
14	OXFORD HYDRO CONOVER NC	TRANS	100.00	6.90	
15	OXFORD HYDRO CONOVER NC	TRANS	100.00	6.90	
16	OXFORD RD RET DURHAM NC	DIST	100.00	13.00	
17	OXFORD RD RET DURHAM NC	DIST	100.00	13.00	
18	OYAMA RET HICKORY NC	DIST	100.00	13.00	
19	OYAMA RET HICKORY NC	DIST	100.00	13.00	
20	PACOLET RET PACOLET SC	DIST	44.00	6.90	
21	PACOLET RET PACOLET SC	DIST	44.00	6.90	
22	PACOLET RET PACOLET SC	DIST	44.00	6.90	
23	PACOLET RET PACOLET SC	DIST	44.00	6.90	
24	PACOLET TIE PACOLET SC	TRANS	230.00	100.00	13.00
25	PACOLET TIE PACOLET SC	TRANS	230.00	100.00	44.00
26	PACOLET TIE PACOLET SC	TRANS	230.00	100.00	44.00
27	PARADISE RET FOREST CITY NC	DIST	44.00	13.00	
28	PARK RD RET CHARLOTTE NC	DIST	100.00	13.00	
29	PARK RD RET CHARLOTTE NC	DIST	100.00	13.00	
30	PARK RD RET CHARLOTTE NC	DIST	100.00	13.00	
31	PARKWAY SS GROVER NC	DIST	100.00	13.00	
32	PARKWAY SS GROVER NC	DIST	100.00	13.00	
33	PARKWOOD RET DURHAM NC	DIST	100.00	24.00	
34	PARKWOOD TIE DURHAM NC	TRANS	230.00	100.00	44.00
35	PARKWOOD TIE DURHAM NC	TRANS	230.00	100.00	44.00
36	PARKWOOD TIE DURHAM NC	TRANS	230.00	100.00	44.00
37	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
38	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
39	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
40	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
2	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
3	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
4	PARKWOOD TIE DURHAM NC	TRANS	44.00	0.40	
5	PARKWOOD TIE DURHAM NC	TRANS	13.00	0.40	
6	PATTERSON SPRINGS RET SHELBY NC	DIST	100.00	13.00	
7	PATTERSON SPRINGS RET SHELBY NC	DIST	100.00	13.00	
8	PEACE HAVEN RD RET CLEMMONS NC	DIST	100.00	13.00	
9	PEACE HAVEN RD RET CLEMMONS NC	DIST	100.00	13.00	
10	PEACH VALLEY TIE SPARTANBURG SC	TRANS	230.00	100.00	44.00
11	PEACH VALLEY TIE SPARTANBURG SC	TRANS	230.00	100.00	44.00
12	PEACH VALLEY TIE SPARTANBURG SC	TRANS	230.00	100.00	44.00
13	PEACH VALLEY TIE SPARTANBURG SC	TRANS	44.00		
14	PEACH VALLEY TIE SPARTANBURG SC	TRANS	44.00		
15	PEACH VALLEY TIE SPARTANBURG SC	TRANS	44.00	0.40	
16	PEACOCK TIE GASTONIA NC	TRANS	230.00	100.00	44.00
17	PEACOCK TIE GASTONIA NC	TRANS	230.00	100.00	44.00
18	PEACOCK TIE GASTONIA NC	TRANS	100.00	13.00	
19	PEACOCK TIE GASTONIA NC	TRANS	44.00		
20	PEACOCK TIE GASTONIA NC	TRANS	44.00	0.40	
21	PEACOCK TIE GASTONIA NC	TRANS	44.00		
22	PEARMAN SS ANDERSON SC	DIST	100.00	13.00	
23	PEARMAN SS ANDERSON SC	DIST	100.00	13.00	
24	PEBBLE CREEK RET GREENVILLE SC	DIST	100.00	13.00	
25	PEBBLE CREEK RET GREENVILLE SC	DIST	100.00	13.00	
26	PEELER RET GAFFNEY SC	DIST	44.00	13.00	
27	PEELER RET GAFFNEY SC	DIST	44.00	13.00	
28	PELHAM RET TAYLORS SC	DIST	100.00	24.00	
29	PELHAM RET TAYLORS SC	DIST	100.00	24.00	
30	PELZER RET PELZER SC	DIST	44.00	13.00	
31	PENDLETON RET PENDLETON SC	DIST	44.00	2.40	
32	PENDLETON RET PENDLETON SC	DIST	44.00	2.40	
33	PENDLETON RET PENDLETON SC	DIST	44.00	2.40	
34	PENDLETON RET PENDLETON SC	DIST	44.00	6.90	2.40
35	PENDLETON RET PENDLETON SC	DIST	44.00	13.00	
36	PERTH RD RET TROUTMAN NC	DIST	44.00	24.00	
37	PERTH RD RET TROUTMAN NC	DIST	44.00	13.00	
38	PETERS CREEK RET SPARTANBURG SC	DIST	44.00	13.00	
39	PFAFFTOWN RET WINSTON-SALEM NC	DIST	100.00	13.00	
40	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
2	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
3	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
4	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
5	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
6	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
7	PICKENS TIE PICKENS SC	TRANS	100.00	44.00	
8	PICKENS TIE PICKENS SC	TRANS	100.00	44.00	
9	PICKENS TIE PICKENS SC	TRANS	100.00	44.00	
10	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
11	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
12	PIEDMONT RET PIEDMONT SC	DIST	44.00	13.00	6.90
13	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
14	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
15	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
16	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
17	PIEDMONT RET PIEDMONT SC	DIST	13.00	2.40	
18	PIERCETOWN SS ANDERSON SC	DIST	100.00	13.00	
19	PIERCETOWN SS ANDERSON SC	DIST	100.00	13.00	
20	PINCH GUT CREEK RET NEWTON NC	DIST	100.00	13.00	
21	PINEVILLE CITY DEL 1 PINEVILLE NC	DIST	44.00	13.00	
22	PINEVILLE CITY DEL 1 PINEVILLE NC	DIST	44.00	13.00	
23	PINEVILLE CITY DEL 2 PINEVILLE NC	DIST	100.00	13.00	
24	PINEWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
25	PINEWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
26	PINK HARRILL TIE CAROLEEN NC	TRANS	100.00	44.00	
27	PINK HARRILL TIE CAROLEEN NC	TRANS	100.00	44.00	
28	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
29	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
30	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
31	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
32	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
33	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
34	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
35	PINNACLE TIE PINNACLE NC	TRANS	24.00	0.20	
36	PIONEER AVE RET CHARLOTTE NC	DIST	100.00	24.00	
37	PIONEER AVE RET CHARLOTTE NC	DIST	100.00	24.00	
38	PIPER GLEN RET CHARLOTTE NC	DIST	100.00	24.00	
39	PIPER GLEN RET CHARLOTTE NC	DIST	100.00	24.00	
40	PIPER GLEN RET CHARLOTTE NC	DIST	100.00	24.00	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PISGAH TIE PISGAH FOREST NC	TRANS	230.00	100.00	44.00
2	PISGAH TIE PISGAH FOREST NC	TRANS	230.00	100.00	44.00
3	PISGAH TIE PISGAH FOREST NC	TRANS	100.00	44.00	
4	PISGAH TIE PISGAH FOREST NC	TRANS	100.00	100.00	13.00
5	PISGAH TIE PISGAH FOREST NC	TRANS	100.00	100.00	13.00
6	PISGAH TIE PISGAH FOREST NC	TRANS	44.00		
7	PISGAH TIE PISGAH FOREST NC	TRANS	44.00		
8	PISGAH TIE PISGAH FOREST NC	TRANS	44.00	0.40	
9	PITTS SCHOOL RET CONCORD NC	DIST	100.00	13.00	
10	PLAINVIEW RET ANDERSON SC	DIST	100.00	13.00	
11	PLAINVIEW RET ANDERSON SC	DIST	100.00	13.00	
12	PLEASANT GARDEN RET PLEASANT GARDEN NC	DIST	44.00	13.00	
13	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	230.00	100.00	44.00
14	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	230.00	100.00	44.00
15	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	230.00	100.00	44.00
16	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
17	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
18	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
19	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
20	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	44.00		
21	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00		
22	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00		
23	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00		
24	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00		
25	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	44.00	0.40	
26	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	24.00	0.40	
27	POPE RD RET DURHAM NC	DIST	100.00	24.00	
28	POPE RD RET DURHAM NC	DIST	100.00	24.00	
29	POPLAR TENT RET CONCORD NC	DIST	100.00	13.00	
30	POPLAR TENT RET CONCORD NC	DIST	100.00	13.00	
31	POWDERSVILLE RET POWDERSVILLE SC	DIST	44.00	13.00	
32	POWDERSVILLE RET POWDERSVILLE SC	DIST	44.00	13.00	
33	PROCTER & GAMBLE GBORO PL T&D GREENSBORO NC	DIST	44.00	13.00	
34	PROPST RET HICKORY NC	DIST	44.00	13.00	
35	PROPST RET HICKORY NC	DIST	44.00	13.00	
36	PROVOL RET CHARLOTTE NC	DIST	100.00	24.00	
37	PROVOL RET CHARLOTTE NC	DIST	100.00	24.00	
38	PROVOL RET CHARLOTTE NC	DIST	100.00	24.00	
39	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	13.00	
40	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	24.00	
2	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	24.00	
3	RAGSDALE RET JAMESTOWN NC	DIST	100.00	24.00	
4	RAGSDALE RET JAMESTOWN NC	DIST	100.00	24.00	
5	RANDLEMAN RD RET RANDLEMAN NC	DIST	100.00	13.00	4.10
6	RANDLEMAN RD RET RANDLEMAN NC	DIST	100.00	13.00	
7	RANDOLPH AVE RET GREENSBORO NC	DIST	100.00	24.00	
8	RANDOLPH AVE RET GREENSBORO NC	DIST	100.00	24.00	
9	RANDOLPH AVE RET GREENSBORO NC	DIST	100.00	24.00	
10	RANKIN AVE RET MOUNT HOLLY NC	DIST	100.00	13.00	
11	RANKIN AVE RET MOUNT HOLLY NC	DIST	100.00	13.00	
12	REAMES RD RET CHARLOTTE NC	DIST	100.00	24.00	
13	REAMES RD RET CHARLOTTE NC	DIST	100.00	24.00	
14	REAMES RD RET CHARLOTTE NC	DIST	100.00	24.00	
15	RED RAIDER RET BELMONT NC	DIST	100.00	13.00	
16	RED ROSE RET LANCASTER SC	DIST	100.00	13.00	
17	RED ROSE RET LANCASTER SC	DIST	100.00	13.00	
18	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
19	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
20	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
21	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
22	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	44.00	24.00
23	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	44.00	24.00
24	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	44.00	24.00
25	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	
26	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	
27	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	4.10
28	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	4.10
29	REMOUNT RD RET CHARLOTTE NC	DIST	100.00	13.00	
30	REMOUNT RD RET CHARLOTTE NC	DIST	100.00	13.00	
31	RESEARCH TRIANGLE RET DURHAM NC	DIST	100.00	24.00	
32	RESEARCH TRIANGLE RET DURHAM NC	DIST	100.00	24.00	
33	RESEARCH TRIANGLE RET DURHAM NC	DIST	100.00	24.00	
34	RHODHISS HYDRO PL RHODHISS NC	TRANS	46.00	6.60	
35	RHODHISS HYDRO PL RHODHISS NC	TRANS	46.00	6.60	
36	RHODHISS HYDRO PL RHODHISS NC	TRANS	46.00	6.60	
37	RHODHISS TIE RHODHISS NC	TRANS	100.00	44.00	
38	RHODHISS TIE RHODHISS NC	TRANS	100.00	44.00	
39	RHODHISS TIE RHODHISS NC	TRANS	44.00	0.24	
40	RICH MOUNTAIN RET BREVARD NC	DIST	100.00	13.00	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	RICH MOUNTAIN RET BREVARD NC	DIST	100.00	13.00	
2	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
3	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
4	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
5	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
6	RIDGEVIEW RET EDEN NC	DIST	100.00	13.00	
7	RIDGEVIEW RET EDEN NC	DIST	100.00	13.00	
8	RIVER HILLS RET CLOVER SC	DIST	100.00	24.00	
9	RIVER HILLS RET CLOVER SC	DIST	100.00	24.00	
10	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	100.00	44.00	
11	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	100.00	44.00	
12	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	100.00	44.00	
13	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	44.00	13.00	
14	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	100.00	13.00	
15	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	100.00	13.00	
16	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	100.00	13.00	
17	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	100.00	13.00	
18	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	100.00	24.00	
19	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	230.00	24.00	
20	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	100.00	24.00	
21	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	100.00	13.00	13.00
22	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	44.00	2.40	
23	RIVERSTONE RET FOREST CITY NC	DIST	100.00	13.00	
24	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
25	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
26	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
27	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
28	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00	34.50	
29	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
30	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
31	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
32	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
33	ROBERTA RD RET CONCORD NC	DIST	44.00	13.00	
34	ROBERTA RD RET CONCORD NC	DIST	44.00	13.00	
35	ROCHESTER TIE NEWRY SC	TRANS	100.00	44.00	
36	ROCK HILL CITY DEL 4 ROCK HILL SC	DIST	100.00	24.00	13.00
37	ROCK HILL CITY DEL 4 ROCK HILL SC	DIST	100.00	24.00	13.00
38	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
39	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
40	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
2	ROCKETT RET CONOVER NC	DIST	100.00	13.00	
3	ROCKETT RET CONOVER NC	DIST	100.00	13.00	
4	ROCKWELL RET ROCKWELL NC	DIST	100.00	13.00	
5	ROCKWELL RET ROCKWELL NC	DIST	100.00	13.00	
6	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
7	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
8	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
9	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
10	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	2.40	0.40	
11	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	2.40	0.40	
12	ROPER MTN RET GREENVILLE SC	DIST	100.00	13.00	
13	ROPER MTN RET GREENVILLE SC	DIST	100.00	13.00	
14	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
15	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
16	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
17	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
18	ROSMAN SS ROSMAN NC	DIST	44.00	6.90	2.40
19	ROSMAN SS ROSMAN NC	DIST	44.00	6.90	2.40
20	ROSMAN SS ROSMAN NC	DIST	44.00	13.00	6.90
21	ROSMAN SS ROSMAN NC	DIST	44.00	13.00	6.90
22	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	44.00	13.00	
23	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
24	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
25	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
26	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
27	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
28	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
29	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
30	ROYAL RET CHARLOTTE NC	DIST	100.00	24.00	
31	ROYAL RET CHARLOTTE NC	DIST	100.00	24.00	
32	ROZZELLES RET CHARLOTTE NC	DIST	100.00	13.00	
33	ROZZELLES RET CHARLOTTE NC	DIST	100.00	13.00	
34	RUDD RET GREENSBORO NC	DIST	100.00	24.00	
35	RUDD RET GREENSBORO NC	DIST	100.00	24.00	
36	RUFFIN RET RUFFIN NC	DIST	44.00	13.00	
37	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
38	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
39	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
40	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	RURAL HALL RET RURAL HALL NC	DIST	44.00	13.00	
2	RURAL HALL RET RURAL HALL NC	DIST	44.00	13.00	
3	RURAL HALL TIE RURAL HALL NC	TRANS	230.00	100.00	44.00
4	RURAL HALL TIE RURAL HALL NC	TRANS	230.00	100.00	44.00
5	RURAL HALL TIE RURAL HALL NC	TRANS	230.00	100.00	44.00
6	RURAL HALL TIE RURAL HALL NC	TRANS	44.00	0.40	
7	RURAL HALL TIE RURAL HALL NC	TRANS	44.00		
8	RUTHERFORD COLLEGE RET RUTHERFORD COLLEGE	DIST	44.00	24.00	13.00
9	RUTHERFORD COLLEGE RET RUTHERFORD COLLEGE	DIST	44.00	13.00	
10	RUTLEDGE TIE MT AIRY NC	TRANS	100.00	44.00	
11	RUTLEDGE TIE MT AIRY NC	TRANS	100.00	44.00	
12	S CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	
13	S CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	
14	S FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
15	S FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
16	S GASTONIA RET GASTONIA NC	DIST	44.00	13.00	
17	S GASTONIA RET GASTONIA NC	DIST	44.00	13.00	
18	S HICKORY RET HICKORY NC	DIST	100.00	13.00	
19	S HICKORY RET HICKORY NC	DIST	100.00	13.00	
20	S SHELBY SS SHELBY NC	DIST	44.00	13.00	
21	S SYLVA RET SYLVA NC	DIST	67.00	13.20	
22	SADLER TIE REIDSVILLE NC	TRANS	230.00	100.00	44.00
23	SADLER TIE REIDSVILLE NC	TRANS	230.00	100.00	44.00
24	SADLER TIE REIDSVILLE NC	TRANS	44.00		
25	SADLER TIE REIDSVILLE NC	TRANS	44.00	0.40	
26	SALISBURY MN SALISBURY NC	TRANS	100.00	13.00	
27	SALISBURY MN SALISBURY NC	TRANS	100.00	13.00	
28	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	
29	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	
30	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	
31	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
32	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
33	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
34	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
35	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
36	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
37	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
38	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
39	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
40	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

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1	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
2	SALISBURY MN SALISBURY NC	TRANS	24.00	0.20	
3	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
4	SALUDA RET SALUDA NC	DIST	44.00	6.90	
5	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
6	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
7	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
8	SALUDA RET SALUDA NC	DIST	44.00	6.90	
9	SALUDA RET SALUDA NC	DIST	44.00	6.90	
10	SANDS RD RET REIDSVILLE NC	DIST	100.00	24.00	
11	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
12	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
13	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
14	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
15	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	6.90	2.40
16	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	6.90	2.40
17	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	6.90	2.40
18	SANDY SPRINGS TIE SANDY SPRINGS SC	TRANS	100.00	44.00	
19	SANDY SPRINGS TIE SANDY SPRINGS SC	TRANS	100.00	44.00	
20	SANDY SPRINGS TIE SANDY SPRINGS SC	TRANS	24.00	0.20	
21	SAPPHIRE RET CASHIERS NC	DIST	66.00	13.00	
22	SAWMILLS RET SAWMILLS NC	DIST	44.00	13.00	
23	SAWMILLS RET SAWMILLS NC	DIST	44.00	13.00	
24	SAXAPAHAW RET SAXAPAHAW NC	DIST	44.00	13.00	
25	SAXAPAHAW RET SAXAPAHAW NC	DIST	44.00	13.00	
26	SCUFFLETOWN RET SIMPSONVILLE SC	DIST	100.00	13.00	
27	SEDGE GARDEN RET KERNERSVILLE NC	DIST	100.00	13.00	
28	SEDGE GARDEN RET KERNERSVILLE NC	DIST	100.00	13.00	
29	SEDGE GARDEN RET KERNERSVILLE NC	DIST	100.00	24.00	
30	SENECA CITY DEL 1 SENECA SC	DIST	100.00	13.00	
31	SENECA CITY DEL 2 SENECA SC	DIST	100.00	13.00	
32	SENECA TIE SENECA SC	TRANS	100.00	44.00	
33	SENECA TIE SENECA SC	TRANS	100.00	44.00	
34	SEVENTH ST RET BURLINGTON NC	DIST	100.00	24.00	
35	SEVENTH ST RET BURLINGTON NC	DIST	100.00	24.00	
36	SEVENTH ST RET BURLINGTON NC	DIST	24.00	6.90	2.40
37	SEVENTH ST RET BURLINGTON NC	DIST	24.00	6.90	2.40
38	SEVENTH ST RET BURLINGTON NC	DIST	24.00	6.90	2.40
39	SEVENTH ST RET BURLINGTON NC	DIST	24.00	2.40	
40	SEWARD RET WINSTON-SALEM NC	DIST	100.00	24.00	

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1	SEWARD RET WINSTON-SALEM NC	DIST	100.00	24.00	
2	SHACKTOWN RET YADKINVILLE NC	DIST	100.00	13.00	
3	SHADY GROVE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
4	SHADY GROVE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
5	SHADY GROVE TIE GREENVILLE SC	TRANS	44.00		
6	SHADY GROVE TIE GREENVILLE SC	TRANS	44.00		
7	SHADY GROVE TIE GREENVILLE SC	TRANS	44.00	0.40	
8	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
9	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
10	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
11	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
12	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
13	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
14	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
15	SHARON RET CHARLOTTE NC	DIST	100.00	24.00	
16	SHARON RET CHARLOTTE NC	DIST	100.00	24.00	
17	SHATTALON SW STA WINSTON-SALEM NC	TRANS	100.00	13.00	
18	SHATTALON SW STA WINSTON-SALEM NC	TRANS	100.00	13.00	
19	SHELBY CITY DEL 8 SHELBY NC	DIST	44.00	13.00	
20	SHELBY CITY DEL 8 SHELBY NC	DIST	44.00	13.00	
21	SHELBY MN SHELBY NC	DIST	44.00	2.40	
22	SHELBY MN SHELBY NC	DIST	44.00	2.40	
23	SHELBY MN SHELBY NC	DIST	44.00	2.40	
24	SHELBY MN SHELBY NC	DIST	44.00	2.40	
25	SHELBY TIE SHELBY NC	TRANS	230.00	100.00	44.00
26	SHELBY TIE SHELBY NC	TRANS	230.00	100.00	44.00
27	SHELBY TIE SHELBY NC	TRANS	230.00	100.00	44.00
28	SHELBY TIE SHELBY NC	TRANS	44.00		
29	SHELBY TIE SHELBY NC	TRANS	44.00		
30	SHELBY TIE SHELBY NC	TRANS	44.00	2.40	0.60
31	SHELBY TIE SHELBY NC	TRANS	44.00	2.40	0.60
32	SHELBY TIE SHELBY NC	TRANS	44.00	2.40	0.60
33	SHERRILLS FORD SS SHERRILLS FORD NC	DIST	44.00	13.00	
34	SHERRILLS FORD SS SHERRILLS FORD NC	DIST	44.00	13.00	
35	SHOPTON RET CHARLOTTE NC	DIST	100.00	24.00	
36	SHORTOFF RET HIGHLANDS NC	DIST	66.00	13.00	
37	SIX MILE RET SIX MILE SC	DIST	44.00	13.00	
38	SMITHTOWN RET SMITHTOWN NC	DIST	44.00	13.00	
39	SOUTHBOUND RET WINSTON-SALEM NC	DIST	100.00	24.00	
40	SOUTHBOUND RET WINSTON-SALEM 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

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1	SOUTHBOUND RET WINSTON-SALEM NC	DIST	100.00	13.00	
2	SOUTHPORT RD RET SPARTANBURG SC	DIST	100.00	13.00	
3	SPARTAN GREEN RET DUNCAN SC	DIST	100.00	24.00	
4	SPARTAN GREEN RET DUNCAN SC	DIST	100.00	24.00	
5	SPARTAN HEIGHTS RET HENDERSONVILLE NC	DIST	44.00	13.00	
6	SPARTAN HEIGHTS RET HENDERSONVILLE NC	DIST	44.00	13.00	
7	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
8	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
9	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
10	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
11	SPEEDWAY RET HARRISBURG NC	DIST	100.00	24.00	
12	SPEEDWAY RET HARRISBURG NC	DIST	13.00		
13	SPRINGFIELD RET CHARLOTTE NC	DIST	100.00	24.00	
14	SPRINGFIELD RET CHARLOTTE NC	DIST	100.00	24.00	
15	SPRINGS IND SS FORT LAWN SC	DIST	100.00	24.00	13.00
16	SPRINGS IND SS FORT LAWN SC	DIST	13.00		
17	ST MARKS RET BURLINGTON NC	DIST	100.00	24.00	
18	ST MARKS RET BURLINGTON NC	DIST	100.00	24.00	
19	ST STEPHENS RET HICKORY NC	DIST	100.00	13.00	
20	ST STEPHENS RET HICKORY NC	DIST	100.00	13.00	
21	STALLINGS RD RET DURHAM NC	DIST	100.00	13.00	
22	STALLINGS RD RET DURHAM NC	DIST	100.00	24.00	
23	STAMEY TIE STATESVILLE NC	TRANS	230.00	100.00	13.00
24	STAMEY TIE STATESVILLE NC	TRANS	230.00	100.00	13.00
25	STAMEY TIE STATESVILLE NC	TRANS	230.00	100.00	44.00
26	STAMEY TIE STATESVILLE NC	TRANS	13.00	0.40	
27	STAMEY TIE STATESVILLE NC	TRANS	13.00	0.40	
28	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
29	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
30	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
31	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
32	STARTOWN RET NEWTON NC	DIST	44.00	13.00	
33	STARTOWN RET NEWTON NC	DIST	44.00	13.00	
34	STATESVILLE CITY DEL 2 STATESVILLE NC	DIST	100.00	24.00	
35	STATESVILLE CITY DEL 2 STATESVILLE NC	DIST	100.00	24.00	13.00
36	STATESVILLE CITY DEL 3 STATESVILLE NC	DIST	100.00	24.00	
37	STATESVILLE RD RET SALISBURY NC	DIST	100.00	13.00	
38	STATESVILLE RD RET SALISBURY NC	DIST	100.00	13.00	
39	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	44.00	
40	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	44.00	

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1	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	44.00	
2	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
3	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
4	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
5	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
6	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
7	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
8	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
9	STEELE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
10	STEELE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
11	STOUTS RET STOUTS NC	DIST	100.00	24.00	
12	STOUTS RET STOUTS NC	DIST	100.00	24.00	
13	STOUTS RET STOUTS NC	DIST	100.00	24.00	
14	SUGAR HILL TIE MARION NC	TRANS	100.00	44.00	
15	SUGAR HILL TIE MARION NC	TRANS	100.00	44.00	
16	SUGAR HILL TIE MARION NC	TRANS	24.00	0.20	
17	SUMMERFIELD RET SUMMERFIELD NC	DIST	100.00	24.00	
18	SUMMERFIELD RET SUMMERFIELD NC	DIST	100.00	24.00	
19	SUMMEY ST RET CLEMSON SC	DIST	100.00	13.00	
20	SUMMEY ST RET CLEMSON SC	DIST	100.00	13.00	
21	SUMMEY ST RET CLEMSON SC	DIST	100.00	13.00	
22	SUMNER RET SALISBURY NC	DIST	100.00	13.00	
23	SUMNER RET SALISBURY NC	DIST	100.00	13.00	
24	SUN CITY YORK SC	DIST	100.00	24.00	
25	SUNSET RET CHARLOTTE NC	DIST	100.00	13.00	
26	SUNSET RET CHARLOTTE NC	DIST	100.00	13.00	
27	SWAIMTOWN RET WINSTON-SALEM NC	DIST	100.00	13.00	
28	SWAIMTOWN RET WINSTON-SALEM NC	DIST	100.00	13.00	
29	SWAIN TIE BRYSON CITY NC	TRANS	161.00	66.00	
30	SWAIN TIE BRYSON CITY NC	TRANS	161.00	66.00	
31	SWAIN TIE BRYSON CITY NC	TRANS	170.00	66.00	
32	SWAIN TIE BRYSON CITY NC	TRANS	69.00	13.00	
33	SWAIN TIE BRYSON CITY NC	TRANS	69.00	13.00	
34	SWEETWATER RET HICKORY NC	DIST	100.00	13.00	
35	SWEETWATER RET HICKORY NC	DIST	100.00	13.00	
36	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	100.00	44.00	
37	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	100.00	44.00	
38	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	44.00	13.00	
39	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	44.00	13.00	
40	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	24.00	0.20	

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TABERNACLE CHURCH RET GREENSBORO NC	DIST	44.00	13.00	
2	TABLE ROCK TIE MORGANTON NC	TRANS	100.00	44.00	33.00
3	TABLE ROCK TIE MORGANTON NC	TRANS	100.00	44.00	
4	TABLE ROCK TIE MORGANTON NC	TRANS	100.00	44.00	33.00
5	TABLE ROCK TIE MORGANTON NC	TRANS	44.00		
6	TABLE ROCK TIE MORGANTON NC	TRANS	24.00	0.20	
7	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
8	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
9	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
10	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
11	TARRANT RD RET GREENSBORO NC	DIST	100.00	24.00	
12	TARRANT RD RET GREENSBORO NC	DIST	100.00	24.00	
13	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	44.00	
14	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	44.00	
15	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
16	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
17	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
18	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	24.00	0.20	
19	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
20	TECHNOLOGY RET CHARLOTTE NC	DIST	100.00	24.00	
21	TECHNOLOGY RET CHARLOTTE NC	DIST	100.00	24.00	
22	TEGA CAY RET FORT MILL SC	DIST	100.00	24.00	
23	TEGA CAY RET FORT MILL SC	DIST	100.00	24.00	13.00
24	TENNESSEE CREEK HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
25	THIRD AVE RET HICKORY NC	DIST	100.00	13.00	
26	THIRD AVE RET HICKORY NC	DIST	100.00	13.00	
27	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
28	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
29	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
30	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
31	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
32	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
33	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
34	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
35	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
36	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
37	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
38	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
39	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	66.00	
40	THORPE HYDRO TUCKASEGEE 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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	13.00	
2	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
3	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
4	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
5	THORPE HYDRO TUCKASEGEE NC	TRANS	6.90		
6	THRIFT RET CHARLOTTE NC	DIST	100.00	13.00	
7	THRIFT RET CHARLOTTE NC	DIST	100.00	13.00	
8	TIGER TIE DUNCAN SC	TRANS	230.00	100.00	44.00
9	TIGER TIE DUNCAN SC	TRANS	230.00	100.00	44.00
10	TIGER TIE DUNCAN SC	TRANS	230.00	100.00	44.00
11	TIGER TIE DUNCAN SC	TRANS	44.00		
12	TIGER TIE DUNCAN SC	TRANS	44.00		
13	TIGER TIE DUNCAN SC	TRANS	44.00	0.40	
14	TIGER TIE DUNCAN SC	TRANS	44.00	0.40	
15	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
16	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
17	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
18	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
19	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
20	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
21	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
22	TNS M GREEN PL STA 3 GREER SC	DIST	100.00	13.00	
23	TOAST RET TOAST NC	DIST	100.00	13.00	
24	TOAST RET TOAST NC	DIST	100.00	13.00	
25	TOXAWAY TIE ANDERSON SC	TRANS	100.00	44.00	24.00
26	TOXAWAY TIE ANDERSON SC	TRANS	100.00	44.00	24.00
27	TOXAWAY TIE ANDERSON SC	TRANS	100.00	13.00	
28	TOXAWAY TIE ANDERSON SC	TRANS	100.00	13.00	
29	TOXAWAY TIE ANDERSON SC	TRANS	100.00	13.00	
30	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
31	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
32	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
33	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
34	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
35	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
36	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
37	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
38	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
39	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
40	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
2	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
3	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
4	TREMONT RET LENOIR NC	DIST	44.00	13.00	
5	TREMONT RET LENOIR NC	DIST	44.00	13.00	
6	TREYBURN RET DURHAM NC	DIST	100.00	24.00	
7	TREYBURN RET DURHAM NC	DIST	100.00	24.00	
8	TRIAD PARK RET KERNERSVILLE NC	DIST	100.00	13.00	
9	TRIAD PARK RET KERNERSVILLE NC	DIST	100.00	13.00	
10	TRIANGLE RET LOWESVILLE NC	DIST	100.00	24.00	
11	TRIANGLE RET LOWESVILLE NC	DIST	100.00	13.00	4.10
12	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
13	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
14	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
15	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
16	TRIBBLE ST RET ANDERSON SC	DIST	44.00	2.40	0.60
17	TRIBBLE ST RET ANDERSON SC	DIST	44.00	2.40	0.60
18	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
19	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
20	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
21	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
22	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
23	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
24	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
25	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
26	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
27	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
28	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	
29	TRIPLETT RET MOORESVILLE NC	DIST	100.00	13.00	
30	TRIPLETT RET MOORESVILLE NC	DIST	100.00	13.00	6.90
31	TROLLINGWOOD RET HAW RIVER NC	DIST	100.00	24.00	
32	TROLLINGWOOD RET HAW RIVER NC	DIST	100.00	24.00	
33	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
34	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
35	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
36	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
37	TROUTMAN RET TROUTMAN NC	DIST	44.00	13.00	6.90
38	TROUTMAN RET TROUTMAN NC	DIST	44.00	13.00	6.90
39	TROUTMAN RET TROUTMAN NC	DIST	44.00	13.00	6.90
40	TRYON RET TRYON NC	DIST	44.00	6.90	2.40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
2	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
3	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
4	TRYON RET TRYON NC	DIST	44.00	13.00	
5	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	230.00	161.00	13.00
6	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	230.00	161.00	13.00
7	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	13.00	0.40	
8	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	13.00	0.40	
9	TUCKERS CREEK RET BREVARD NC	DIST	44.00	13.00	
10	TUCKERS CREEK RET BREVARD NC	DIST	44.00	13.00	
11	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00	2.40	0.60
12	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00	2.40	0.60
13	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00	2.40	0.60
14	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00		
15	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	2.40		
16	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	2.40		
17	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	24.00	0.20	
18	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	6.90	
19	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	6.90	
20	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	6.90	
21	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	24.00	6.90
22	TYSINGER RD RET MIDWAY NC	DIST	100.00	13.00	
23	UNA RET SPARTANBURG SC	DIST	100.00	13.00	
24	UNA RET SPARTANBURG SC	DIST	100.00	13.00	
25	UNC-CH DEL 1 CAMERON CHAPEL HILL NC	DIST	100.00	13.00	
26	UNC-CH DEL 1 CAMERON CHAPEL HILL NC	DIST	100.00	13.00	
27	UNC-CH DEL 2 SOUTH CHAPEL HILL NC	DIST	100.00	13.00	
28	UNIFI MADISON T&D MADISON NC	DIST	100.00	24.00	
29	UNIFI YADKINVILLE T&D STA 1 YADKINVILLE NC	DIST	100.00	13.00	
30	UNIFI YADKINVILLE T&D STA 1 YADKINVILLE NC	DIST	100.00	13.00	
31	UNIFI YADKINVILLE T&D STA 2 YADKINVILLE NC	DIST	100.00	24.00	
32	UNIFI YADKINVILLE T&D STA 2 YADKINVILLE NC	DIST	100.00	24.00	
33	UNIV OF N C CHARLOTTE STA 2 CHARLOTTE NC	DIST	100.00	44.00	
34	UPWARD RD RET HENDERSONVILLE NC	DIST	100.00	13.00	
35	UPWARD RD RET HENDERSONVILLE NC	DIST	100.00	13.00	
36	URQUHART STEAM STA AUGUSTA GA	TRANS	100.00	13.00	
37	VALDESE RET VALDESE NC	DIST	44.00	2.40	0.60
38	VALDESE RET VALDESE NC	DIST	44.00	2.40	0.60
39	VALDESE RET VALDESE NC	DIST	44.00	2.40	0.60
40	VALDESE RET VALDESE NC	DIST	44.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS

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1	VALDESE RET VALDESE NC	DIST	44.00	13.00	
2	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
3	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
4	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
5	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
6	VALDESE TIE VALDESE NC	TRANS	100.00	44.00	
7	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
8	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
9	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
10	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
11	VALMEAD RET LENOIR NC	DIST	44.00	13.00	
12	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
13	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
14	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
15	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
16	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
17	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
18	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
19	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
20	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	2.40
21	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	2.40
22	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	2.40
23	VAN WYCK TIE VAN WYCK SC	DIST	100.00	44.00	
24	VAN WYCK TIE VAN WYCK SC	DIST	100.00	44.00	
25	VAN WYCK TIE VAN WYCK SC	DIST	24.00	0.20	
26	VANDALIA RET GREENSBORO NC	DIST	100.00	24.00	
27	VANDALIA RET GREENSBORO NC	DIST	100.00	24.00	
28	VANDALIA RET GREENSBORO NC	DIST	100.00	24.00	
29	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
30	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
31	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
32	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
33	VERDAE RET GREENVILLE SC	DIST	100.00	24.00	
34	VERDAE RET GREENVILLE SC	DIST	100.00	13.00	
35	VICTOR HILL SPARTANBURG SC	DIST	100.00	13.00	
36	VICTOR HILL SPARTANBURG SC	DIST	100.00	13.00	
37	VICTOR HILL SPARTANBURG SC	DIST	100.00	24.00	
38	W FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
39	W FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
40	W GASTONIA RET GASTONIA NC	DIST	100.00	13.00	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

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1	W GASTONIA RET GASTONIA NC	DIST	100.00	13.00	
2	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
3	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
4	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
5	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
6	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
7	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
8	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
9	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
10	W NORWOOD RET NORWOOD NC	DIST	100.00	24.00	
11	W NORWOOD RET NORWOOD NC	DIST	100.00	24.00	
12	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
13	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
14	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
15	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
16	WADDELL RD RET GREENVILLE SC	DIST	100.00	13.00	
17	WADDELL RD RET GREENVILLE SC	DIST	100.00	13.00	
18	WADSWORTH RET SPARTANBURG SC	DIST	100.00	13.00	
19	WADSWORTH RET SPARTANBURG SC	DIST	100.00	13.00	
20	WALDEN RET SPARTANBURG SC	DIST	100.00	24.00	
21	WALHALLA TIE WALHALLA SC	TRANS	100.00	44.00	
22	WALHALLA TIE WALHALLA SC	TRANS	100.00	44.00	
23	WALHALLA TIE WALHALLA SC	TRANS	100.00	44.00	
24	WALHALLA TIE WALHALLA SC	TRANS	44.00	0.20	
25	WALKER TIE HARMONY SC	TRANS	100.00	44.00	
26	WALKER TIE HARMONY SC	TRANS	100.00	44.00	
27	WALKER TIE HARMONY SC	TRANS	24.00	0.20	
28	WALKER TIE HARMONY SC	TRANS	24.00	0.20	
29	WALKERTOWN RET WALKERTOWN NC	DIST	100.00	13.00	
30	WALKERTOWN RET WALKERTOWN NC	DIST	100.00	13.00	
31	WALLACE RD RET MIDLAND NC	DIST	100.00	24.00	
32	WALNUT COVE TIE WALNUT COVE NC	TRANS	100.00	44.00	
33	WALNUT COVE TIE WALNUT COVE NC	TRANS	100.00	44.00	
34	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	24.00	13.00
35	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	24.00	13.00
36	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	13.00	6.90
37	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	13.00	6.90
38	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	13.00	6.90
39	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	24.00	13.00
40	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	13.00	6.90

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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	WALNUT COVE TIE WALNUT COVE NC	TRANS	24.00	0.20	
2	WARE PLACE RET PELZER SC	DIST	44.00	6.90	
3	WARE PLACE RET PELZER SC	DIST	44.00	6.90	
4	WARE PLACE RET PELZER SC	DIST	44.00	6.90	
5	WARE PLACE RET PELZER SC	DIST	44.00	6.90	2.40
6	WARE PLACE RET PELZER SC	DIST	44.00	6.90	
7	WARE PLACE RET PELZER SC	DIST	44.00	6.90	2.40
8	WARE PLACE RET PELZER SC	DIST	44.00	6.90	2.40
9	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
10	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
11	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
12	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
13	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	
14	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
15	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
16	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
17	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
18	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
19	WATEREE HYDRO LUGOFF SC	TRANS	6.90	0.60	
20	WATEREE HYDRO LUGOFF SC	TRANS	6.90	0.60	
21	WATEREE HYDRO LUGOFF SC	TRANS	6.90	0.60	
22	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	0.60
23	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	0.60
24	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	0.60
25	WATERTOWER RET KANNAPOLIS NC	DIST	44.00	13.00	
26	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	
27	WATERTOWER RET KANNAPOLIS NC	DIST	44.00	13.00	
28	WAYNICK RD RET REIDSVILLE NC	DIST	100.00	13.00	
29	WEAVER RET DURHAM NC	DIST	100.00	24.00	
30	WEBBS CHAPEL RET DENVER NC	DIST	44.00	13.00	
31	WEBBS CHAPEL RET DENVER NC	DIST	44.00	13.00	
32	WEBSTER TIE WEBSTER NC	TRANS	161.00	66.00	
33	WEBSTER TIE WEBSTER NC	TRANS	161.00	66.00	
34	WEBSTER TIE WEBSTER NC	TRANS	66.00	13.00	
35	WEBSTER TIE WEBSTER NC	TRANS	66.00	13.00	
36	WEBSTER TIE WEBSTER NC	TRANS	66.00	13.00	
37	WENTWORTH RET WENTWORTH NC	DIST	100.00	13.00	
38	WENTWORTH RET WENTWORTH NC	DIST	100.00	13.00	
39	WESTMINSTER MN WESTMINSTER SC	DIST	100.00	44.00	
40	WESTMINSTER MN WESTMINSTER SC	DIST	100.00	44.00	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	WESTMINSTER MN WESTMINSTER SC	DIST	100.00	44.00	
2	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
3	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
4	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
5	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
6	WHITE CROSS RET WHITE CROSS NC	DIST	44.00	13.00	
7	WHITE PLAINS RET MT AIRY NC	DIST	100.00	13.00	
8	WHITEHALL RET ANDERSON SC	DIST	100.00	13.00	
9	WHITEHALL RET ANDERSON SC	DIST	100.00	13.00	
10	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
11	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
12	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
13	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
14	WHITSETT RET BURLINGTON NC	DIST	100.00	24.00	
15	WHITSETT RET BURLINGTON NC	DIST	100.00	24.00	
16	WILDCAT TIE CORNELIUS NC	TRANS	100.00	44.00	
17	WILDCAT TIE CORNELIUS NC	TRANS	100.00	44.00	
18	WILDCAT TIE CORNELIUS NC	TRANS	100.00	44.00	
19	WILGROVE RET CHARLOTTE NC	DIST	100.00	24.00	
20	WILGROVE RET CHARLOTTE NC	DIST	100.00	24.00	
21	WILKES TIE NORTH WILKESBORO NC	TRANS	100.00	44.00	
22	WILKES TIE NORTH WILKESBORO NC	TRANS	100.00	44.00	
23	WILKES TIE NORTH WILKESBORO NC	TRANS	24.00	0.20	
24	WILLARD RD RET WINSTON-SALEM NC	DIST	100.00	24.00	
25	WILLIAMSBURG RET REIDSVILLE NC	DIST	100.00	13.00	
26	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
27	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
28	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
29	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
30	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
31	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
32	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
33	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
34	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
35	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
36	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
37	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
38	WILLOW CREEK RET HIGH POINT NC	DIST	100.00	13.00	
39	WILLOW CREEK RET HIGH POINT NC	DIST	100.00	13.00	
40	WINECOFF RET CONCORD NC	DIST	44.00	13.00	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
2	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
3	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
4	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
5	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
6	WINECOFF TIE CONCORD NC	TRANS	44.00	0.40	
7	WINECOFF TIE CONCORD NC	TRANS	44.00		
8	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
9	WINECOFF TIE CONCORD NC	TRANS	44.00		
10	WINSTON TIE WINSTON-SALEM NC	TRANS	100.00	13.00	
11	WINTHROP UNIV DEL 3 ROCK HILL SC	DIST	24.00	13.00	
12	WITHERS RET CHARLOTTE NC	DIST	100.00	24.00	
13	WITHERS RET CHARLOTTE NC	DIST	100.00	24.00	
14	WOODLAWN TIE CHARLOTTE NC	TRANS	100.00	13.00	
15	WOODLAWN TIE CHARLOTTE NC	TRANS	100.00	13.00	
16	WOODLAWN TIE CHARLOTTE NC	TRANS	100.00	13.00	
17	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
18	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
19	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
20	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00	0.40	
21	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
22	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
23	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
24	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
25	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
26	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
27	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
28	WOODRUFF TIE WOODRUFF SC	TRANS	24.00	0.20	
29	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
30	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
31	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
32	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
33	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
34	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
35	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
36	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
37	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
38	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
39	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
40	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
2	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
3	YORK E C DEL 11 INDIA HOOK SC	DIST	44.00	13.00	
4	YORK E C DEL 11 INDIA HOOK SC	DIST	44.00	13.00	
5	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
6	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
7	YORK E C DEL 9 HANCOCK SC	DIST	44.00	13.00	
8	YORK RET YORK SC	DIST	100.00	13.00	
9	YORK RET YORK SC	DIST	100.00	13.00	
10	YORK RET YORK SC	DIST	13.00	2.40	0.60
11	YORK RET YORK SC	DIST	13.00	2.40	0.60
12	YORK RET YORK SC	DIST	13.00	2.40	0.60
13	YORK RET YORK SC	DIST	100.00	24.00	13.00
14	ZF TRANSMISSIONS GVILLE LLC GRAY COURT SC	TRANS	100.00	13.00	
15	ZION CHURCH RD RET HICKORY NC	DIST	100.00	13.00	6.90
16					
17	23 STATIONS UNDER 10 MVA CAPACITY	TRANS			
18	FERC SUBCODE = T OR D				
19	213 STATIONS UNDER 10 MVA CAPACITY	DIST			
20	FERC SUBCODE = T OR D				
21	177 STATIONS 10 OR GREATER MVA CAPACITY	TRANS	121969.50	34577.84	6299.90
22	FERC SUBCODE = T OR D				
23	578 STATIONS 10 OR GREATER MVA CAPACITY	DIST	115326.00	20264.20	2343.30
24	FERC SUBCODE = T OR				
25					
26	NC STATIONS FOR INDUSTRIAL CUSTOMERS	INDUSTRIAL			
27	SC STATIONS FOR INDUSTRIAL CUSTOMERS	INDUSTRIAL			
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
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.
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

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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)	
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
500	1		STU			31
320	1		STU			32
500	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

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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

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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
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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
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

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
20	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

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

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
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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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)	
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

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
3	1					26
3	1					27
3	1					28
5	1					29
5	1					30
20	1					31
20	1					32
30	1					33
	1		AUX			34
13	1					35
20	1		2			36
22	1		2			37
175	1		STU			38
101	1		STU			39
1	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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		AUX			2
3		1				3
3	1					4
3	1					5
3	1					6
10	1					7
4		1				8
4	1					9
4	1					10
4	1					11
4	1					12
4	1					13
4	1					14
30	1					15
12	1					16
12	1					17
10	1					18
5	1					19
10	1					20
11	1					21
30	1					22
30	1					23
	1		AUX			24
20	1					25
20	1					26
10	1					27
4	1					28
17	1		AUTO-TRANSFORMER			29
17	1		AUTO-TRANSFORMER			30
17	1		AUTO-TRANSFORMER			31
76	1		AUTO-TRANSFORMER			32
						33
12	1					34
12	1					35
10	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
10	1					3
3	1					4
3	1					5
3	1					6
12	1					7
12	1					8
25	1		STU			9
8	1		STU			10
8	1		STU			11
20	1					12
20	1					13
22	1					14
20	1					15
12	1					16
10	1		GND	1	10,000	17
10	1		GND	1	10,000	18
12	1					19
20	1					20
20	1					21
2		1				22
2	1					23
2	1					24
2	1					25
2		1				26
2	1					27
2	1					28
2	1					29
20	1					30
20	1					31
	1		SS			32
12	1					33
3	1					34
3	1					35
3		1				36
3	1					37
10	1					38
10	1					39
15	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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.
34	1					1
34	1					2
34	1					3
	1		SS			4
	1					5
	1					6
	1					7
12	1					8
12	1					9
12	1					10
12	1					11
12	1					12
13	1					13
13	1					14
13	1					15
13	1					16
12	1					17
12	1					18
13	1					19
20	1					20
20	1					21
10	1					22
10	1					23
20	1					24
20	1					25
20	1					26
10	1					27
12	1					28
12	1					29
400	1					30
300	1					31
1	1					32
10	1					33
10	1					34
10	1					35
10	1					36
3		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.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	1					1
12	1					2
12	1					3
12	1					4
3		1				5
3	1					6
3	1					7
3	1					8
	1		SS			9
	1		SS			10
	1		SS			11
10	1					12
10	1					13
20	1					14
20	1					15
10	1					16
10	1					17
12	1					18
12	1					19
12	1					20
12	1					21
20	1					22
20	1					23
12	1					24
12	1					25
20	1					26
20	1					27
20	1					28
20	1					29
20	1					30
12	1					31
20	1					32
20	1					33
10	1					34
10	1					35
8	1					36
8	1					37
10	1					38
20	1					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
20	1					2
20	1					3
20	1		2			4
8	1					5
8	1					6
12	1					7
12	1					8
1	1					9
1	1					10
1	1					11
1		1				12
2		1				13
2	1					14
2	1					15
2	1					16
12	1					17
12	1					18
13	1		1			19
30	1					20
30	1					21
12	1					22
12	1					23
4		1				24
4	1					25
4	1					26
4	1					27
11	1					28
10	1					29
300	1					30
300	1					31
200	1					32
200	1					33
9	1		GND	1	9,145	34
9	1		GND	1	9,156	35
1	1		SS			36
1	1					37
12	1					38
12	1					39
15	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
15	1					1
12	1					2
30	1					3
30	1					4
30	1					5
20	1					6
20	1					7
12	1					8
12	1					9
30	1					10
30	1					11
30	1					12
12	1					13
12	1					14
2	1					15
2	1					16
2	1					17
3		1				18
1	1					19
1	1					20
1	1					21
10	1					22
8	1					23
8	1					24
12	1					25
12	1					26
12	1					27
10	1					28
10	1					29
2		1				30
2	1					31
2	1					32
2	1					33
20	1					34
20	1					35
	1					36
	1					37
25	1		STU			38
22	1		STU			39
10	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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					1
8	1					2
3		1				3
3	1					4
3	1					5
3	1					6
2	1					7
2	1					8
2	1					9
10	1					10
2	1					11
2	1					12
2	1					13
3		1				14
3	1					15
3	1					16
3	1					17
10	1					18
10	1					19
8	1					20
8	1					21
10	1					22
20	1					23
20	1					24
20	1					25
20	1					26
30	1					27
30	1					28
2	1					29
2	1					30
2	1					31
2	1					32
2	1					33
2	1					34
10	1					35
20	1					36
20	1					37
6		1				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.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
6	1					1
6	1					2
6	1					3
6	1					4
	1		SS			5
	1					6
30	1					7
30	1					8
12	1					9
12	1					10
	1					11
12	1					12
12	1					13
12	1					14
3	1					15
3		1				16
3	1					17
3	1					18
12	1					19
12	1					20
2	1					21
2	1					22
2	1					23
2		1				24
3	1					25
3	1					26
3	1					27
12	1					28
12	1					29
10		1				30
11	1					31
10	1					32
20	1					33
22	1					34
20	1					35
20	1					36
10	1					37
10	1					38
5	1					39
2	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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
20	1					3
20	1					4
20	1					5
12	1					6
12	1					7
12	1					8
12	1					9
12	1					10
13	1					11
22	1					12
20	1					13
30	1					14
30	1					15
30	1					16
1	1					17
1	1					18
1	1					19
2		1				20
10	1					21
10	1					22
11	1					23
8	1		STU			24
8	1		STU			25
8	1		STU			26
8	1		STU			27
20	1					28
20	1					29
14	1					30
14	1					31
12	1					32
12	1					33
37	1					34
37	1					35
37						36
6		1				37
6	1					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.
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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
20	1					2
20	1					3
20	1					4
20	1					5
20	1					6
20	1					7
4	1					8
4	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
	1		SS			18
10	1					19
10	1					20
10	1					21
10	1					22
5	1					23
10	1					24
12	1					25
12	1					26
12	1					27
	1		AUX			28
13	1					29
13	1					30
20	1					31
12	1					32
12	1					33
20	1					34
20	1					35
12	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.
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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
12	1					3
12	1					4
12	1					5
12	1					6
1		1				7
1	1					8
1	1					9
1	1					10
200	1					11
270	1					12
200	1					13
270	1					14
8	1		GND	1	8,230	15
1	1		GND	1	500	16
1	1		GND	1	500	17
1	1		GND	1	500	18
	1		SS			19
	1		SS			20
	1		SS			21
10	1					22
8	1					23
1		1				24
2	1					25
10	1					26
2	1					27
2	1					28
12	1					29
12	1					30
20	1					31
20	1					32
20	1					33
10	1					34
22	1		2			35
20	1					36
30	1					37
30	1					38
	1		AUX			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.
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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
1	1					3
3	1					4
3	1					5
3	1					6
1		1				7
1	1					8
1	1					9
3	1					10
20	1					11
20	1					12
20	1					13
20	1					14
20	1					15
30	1					16
	1					17
11	1					18
2		1				19
2	1					20
2	1					21
2	1					22
1	1					23
1	1					24
1	1					25
5	1					26
5	1					27
10	1					28
10	1		GND	1	10,000	29
20	1					30
20	1					31
30	1					32
30	1					33
30	1					34
20	1					35
20	1					36
3	1					37
3	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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3	1					1
3	1					2
20	1					3
20	1					4
20	1					5
12	1					6
	1					7
20	1					8
20	1					9
20	1					10
10	1					11
300	1					12
300	1					13
19	1		GND	1	19,120	14
1	1		SS			15
20	1					16
20	1					17
20	1					18
12	1					19
12	1					20
20	1					21
20	1					22
3		1				23
3	1					24
3	1					25
3	1					26
60	1					27
60	1					28
30	1					29
30	1					30
	1		SS			31
	1		SS			32
34						33
	1		SS			34
20	1					35
20	1					36
12	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.
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10	1					1
10	1					2
12	1					3
12	1					4
12	1					5
20	1					6
12	1					7
3		1				8
3	1					9
3	1					10
3	1					11
1	1					12
1	1					13
1	1					14
30	1					15
30	1					16
30	1					17
12	1					18
20	1					19
12	1					20
12	1					21
12	1					22
12	1					23
12	1					24
12	1					25
10	1					26
10	1					27
30	1					28
30	1					29
192	1		STU			30
96	1		STU			31
192	1		STU			32
192	1		STU			33
1	1					34
	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
	1					1
1	1					2
1	1					3
3	1					4
500	1					5
500	1					6
500	1					7
192		1				8
12	1					9
12	1					10
12	1					11
10	1					12
10	1					13
20	1					14
20	1					15
20	1					16
205	1		STU			17
1		1				18
1	1		AUX			19
1	1		AUX			20
1	1		AUX			21
1	1		AUX			22
1	1		AUX			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
2		1				32
2	1					33
2	1					34
3	1					35
1		1				36
1	1					37
1	1					38
1	1					39
10	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
10	1					4
8	1					5
12	1					6
12	1					7
20	1					8
20	1					9
3		1				10
3	1					11
3	1					12
3	1					13
10	1					14
10	1					15
20	1					16
22	1		2			17
4		1				18
4	1					19
4	1					20
4	1					21
2		1				22
2	1					23
2	1					24
2	1					25
20	1					26
20	1					27
20	1					28
12	1					29
20	1					30
30	1					31
30	1					32
30	1					33
2	1		GND	1	1,500	34
2	1		GND	1	1,500	35
2	1		GND	1	1,500	36
1	1		GND	1	1,000	37
1	1		GND	1	1,000	38
1	1		GND	1	1,000	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.
3		1				1
3	1					2
3	1					3
3	1					4
11	1					5
22	1					6
20	1					7
4		1				8
4	1					9
4	1					10
4	1					11
4	1					12
4	1					13
4	1					14
4	1					15
4	1					16
400	1					17
400	1					18
19	1		GND	1	19,121	19
19	1		GND	1	19,121	20
2	1		SS			21
4		1				22
4	1					23
4	1					24
4	1					25
4		1				26
4	1					27
4	1					28
4	1					29
	1		SS			30
1		1				31
1	1					32
1	1					33
1	1					34
12	1					35
12	1					36
3		1				37
3	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Total Capacity (In MVa) (k)	Line No.
10	1					1
10	1					2
10	1					3
10	1					4
3	1					5
3	1					6
3	1					7
12	1					8
12	1					9
13	1		1			10
20	1					11
20	1					12
12	1					13
12	1					14
2	1					15
2	1					16
2	1					17
20	1					18
15	1					19
12	1					20
6		1				21
6	1					22
6	1					23
6	1					24
6	1					25
6	1					26
6	1					27
3		1				28
3	1					29
3	1					30
3	1					31
10	1					32
20	1					33
20	1					34
20	1					35
32	1		STU			36
32	1		STU			37
22	1					38
20	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) (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
3		1				3
10	1					4
20	1					5
20	1					6
30	1					7
30	1					8
	1		SS			9
20	1					10
20	1					11
4		1				12
4	1					13
4	1					14
4	1					15
12	1					16
12	1					17
134	1		STU			18
134	1		STU			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
4		1				26
4	1					27
4	1					28
4	1					29
20	1					30
20	1					31
30	1					32
30	1					33
30	1					34
4		1				35
4	1					36
4	1					37
4	1					38
4	1					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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)	
4	1					1
4	1					2
4	1					3
4		1				4
4	1					5
12	1					6
20	1	1				7
20	1					8
5	1					9
	1		SS			10
20	1					11
20	1					12
22	1		2			13
12	1					14
12	1					15
7	1		GND	1	6,859	16
12	1					17
12	1					18
12	1					19
10	1					20
10	1					21
400	1					22
300	1					23
300	1					24
400	1					25
8	1		GND	1	8,230	26
9	1		GND	1	9,145	27
	1					28
	1					29
	1					30
20	1		STU			31
20	1		STU			32
30	1					33
20	1					34
30	1					35
	1		SS			36
12	1					37
12	1					38
12	1					39
12	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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)	
13	1					1
30	1					2
30	1					3
30	1					4
10	1					5
10	1					6
12	1					7
20	1					8
20	1					9
13	1					10
15	1					11
17	1					12
	1					13
	1		GND	1		14
	1		GND	1		15
	1		GND	1		16
20	1					17
12	1					18
34	1					19
20	1					20
	1		SS			21
4		1				22
4	1					23
4	1					24
4	1					25
1		1				26
1	1					27
1	1					28
1	1					29
20	1					30
11	1					31
420	1		STU			32
420	1		STU			33
750	1		STU			34
760	1		STU			35
1	1					36
1	1					37
	1					38
	1					39
10	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10		1				1
30	1					2
30	1					3
30	1					4
30	1					5
30	1					6
30	1					7
11	1					8
10	1					9
	1					10
20	1					11
20	1					12
20	1					13
150	1					14
30	1					15
1	1		GND	1	500	16
1	1		GND	1	500	17
1	1		GND	1	500	18
	1					19
	1					20
	1					21
760	1		STU			22
60	1					23
60	1					24
6	1					25
6	1					26
24	1					27
760	1		STU			28
2	1					29
2	1					30
2	1					31
2	1					32
2	1					33
2	1					34
2	1					35
2	1					36
2	1					37
2	1					38
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.
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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
6	1					9
6	1					10
2		1				11
2		1				12
2		1				13
750	1		STU			14
60	1					15
60	1					16
6	1					17
6	1					18
24	1					19
750	1		STU			20
2	1					21
2	1					22
2	1					23
2	1					24
2	1					25
2	1					26
2	1					27
2	1					28
2	1					29
2	1					30
2	1					31
2	1					32
2	1					33
2	1					34
2	1					35
2	1					36
2	1					37
2	1					38
2	1					39
2	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3		1				1
3	1					2
3	1					3
3	1					4
500		1				5
500	1					6
500	1					7
500	1					8
2	1					9
2	1					10
33	1		RAC			11
33	1		RAC			12
33	1		RAC			13
33	1		RAC			14
33	1		RAC			15
33	1		RAC			16
	1					17
	1					18
1	1					19
1	1					20
33		1				21
20	1					22
20	1					23
1		1				24
1	1					25
1	1					26
1	1					27
1		1				28
1	1					29
1	1					30
1	1					31
5	1					32
12	1					33
12	1					34
12	1					35
12	1					36
	1		AUX			37
30	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
30	1					1
12	1					2
12	1					3
12	1					4
20	1					5
20	1					6
20	1					7
20	1					8
12	1					9
12	1					10
12	1					11
12	1					12
	1	1				13
5	1	1				14
5	1	1				15
5	1	1				16
12	1					17
30	1					18
30	1					19
20	1					20
269	1					21
200	1					22
300	1					23
	1		GND	1		24
9	1		GND	1	9,156	25
1	1		SS			26
3		1				27
3	1					28
3	1					29
3	1					30
20	1					31
12	1					32
12	1					33
	1					34
12	1					35
12	1					36
						37
2	1					38
2	1					39
2	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
4		1				1
4	1					2
4	1					3
4	1					4
20	1					5
20	1					6
20	1					7
20	1					8
20	1					9
10	1					10
30	1					11
30	1					12
10	1					13
20	1					14
20	1					15
20	1					16
10	1					17
10	1					18
10	1					19
12	1					20
12	1					21
12	1					22
12	1					23
	1					24
10	1					25
10	1					26
10	1					27
10	1					28
10	1					29
10	1					30
20	1					31
20	1					32
12	1					33
	1		STATION SERVICE			34
			STATION SERVICE			35
200	1					36
150	1					37
150	1					38
30	1					39
30	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1	1					1
12	1					2
20	1					3
	1					4
2		1				5
2	1					6
2	1					7
2	1					8
6		1				9
10	1					10
10	1					11
10	1					12
3		1				13
3	1					14
3	1					15
3	1					16
10	1					17
10	1					18
1	1					19
1	1					20
1	1					21
3		1				22
3	1					23
3	1					24
3	1					25
20	1					26
20	1					27
12	1					28
20	1					29
12	1					30
15	1					31
3		1				32
3	1					33
3	1					34
3	1					35
2		1				36
2	1					37
2	1					38
2	1					39
10	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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)	
10	1					1
6	1					2
6	1					3
6	1					4
6		1				5
6	1					6
6	1					7
6	1					8
2		1				9
2	1					10
2	1					11
2	1					12
10	1					13
12	1					14
400	1					15
270	1					16
448	1					17
12	1					18
9	1		GND	1	9,156	19
270						20
2	1		SS			21
200	1					22
200	1					23
200	1					24
200	1					25
19	1		GND	1	19,120	26
19	1		GND	1	19,120	27
	1		SS			28
	1		SS			29
	1		SS			30
8	1					31
8	1					32
22	1					33
20	1					34
12	1					35
12	1					36
20	1					37
20	1					38
20	1					39
27	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.
27	1					1
15	1					2
	1		SS			3
	1		SS			4
	1					5
11	1					6
10	1					7
10	1					8
10	1					9
12	1					10
12	1					11
12	1					12
13	1		1			13
22	1					14
20	1					15
30	1					16
30	1					17
30	1					18
30	1					19
10	1					20
11	1					21
300	1					22
448	1					23
400	1					24
2	1		AUX			25
333		1				26
333	1					27
333	1					28
373	1					29
19	1		GND	1	19,120	30
33	1		RAC			31
33	1		RAC			32
33	1		RAC			33
6	1					34
6	1					35
6	1					36
6		1				37
6	1					38
6	1					39
6	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/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
	1		AUX			4
3		1				5
3	1		STU			6
3	1		STU			7
3	1		STU			8
3	1		STU			9
3	1		STU			10
3	1		STU			11
3		1				12
3		1				13
3		1				14
	1					15
	1					16
	1					17
20	1					18
5	1					19
5	1					20
12	1					21
12	1					22
10	1					23
10	1					24
20	1					25
20	1					26
4		1				27
4	1					28
4	1					29
4	1					30
200	1					31
200	1					32
200	1					33
9	1		GND	1	9,156	34
1	1		SS			35
12	1					36
12	1					37
5	1					38
5	1					39
5	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
22	1					5
20	1					6
	1		SS			7
22						8
20	1	1				9
12	1					10
12	1					11
	1					12
	1					13
500		1				14
500	1					15
500	1					16
500	1					17
33	1		RAC			18
33	1		RAC			19
33	1		RAC			20
33	1		RAC			21
33	1		RAC			22
33	1		RAC			23
	1		SS			24
	1		SS			25
1000	1		STU			26
45	1					27
2	1					28
	1					29
2	1					30
2	1					31
2	1					32
2	1					33
2	1					34
2	1					35
2	1					36
2	1					37
	1		AUX			38
30	1					39
52		1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
1000	1		STU			3
45	1					4
2	1					5
	1					6
1	1					7
2		1				8
2	1					9
2	1					10
2	1					11
2	1					12
1	1					13
1	1					14
45	1					15
373		1				16
373	1		STU			17
373	1		STU			18
373	1		STU			19
45	1					20
2	1					21
	1					22
2	1					23
2	1					24
2	1					25
2	1					26
2	1					27
1	1					28
1	1					29
45	1					30
12	1					31
15		1				32
12	1					33
22	1					34
22	1					35
5		1				36
5	1					37
5	1					38
5	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) (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
11	1					4
20	1					5
2		1				6
2	1					7
2	1					8
2	1					9
1	1					10
1	1					11
1	1					12
10	1					13
15	1		STU			14
15	1					15
12	1					16
12	1					17
20	1					18
20	1					19
3		1				20
3	1					21
3	1					22
3	1					23
200	1					24
200	1					25
200	1		4			26
10	1					27
20	1	1				28
20	1					29
20	1					30
10	1					31
12	1					32
20	1					33
300	1					34
300	1					35
269						36
250		1				37
250	1					38
250	1					39
250	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.
280	1					1
280	1					2
280	1					3
2	1		SS			4
1	1					5
20	1					6
20	1					7
20	1					8
20	1					9
200	1					10
200	1					11
400	1					12
29	1		GND	1	28,672	13
29	1		GND	1	28,672	14
1	1		SS			15
400	1					16
400	1					17
12	1					18
19	1					19
1	1					20
19	1					21
12	1					22
12	1					23
20	1					24
20	1					25
5	1					26
5	1					27
20	1	1				28
20	1					29
10	1					30
1	1					31
1	1					32
1	1					33
1		1				34
10	1					35
10	1					36
10	1					37
10	1					38
20	1					39
3		1				40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	1					1
3	1					2
3	1					3
1	1					4
1	1					5
1	1					6
12	1					7
12	1					8
12	1					9
3	1		1			10
3	1		1			11
3	1		1			12
2		1	NULL			13
2	1		1			14
2	1		1			15
2	1		1			16
	1		SS			17
12	1					18
12	1					19
12	1					20
10	1					21
10	1					22
20	1					23
20	1					24
20	1					25
20	1					26
20	1					27
4		1				28
4	1					29
4	1					30
4	1					31
4	1					32
4	1					33
4	1					34
	1					35
22	1		1			36
20	1					37
30	1					38
30	1					39
34	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
200	1					1
200	1					2
30	1					3
60	1					4
60	1					5
19	1		GND	1	19,120	6
9	1		GND	1	9,145	7
1	1		SS			8
20	1					9
20	1					10
20	1					11
10	1					12
300	1					13
300	1					14
300	1					15
500		1				16
500	1					17
500	1					18
500	1					19
29	1		GND	1	28,672	20
33		1				21
33	1		RAC			22
33	1		RAC			23
33	1		RAC			24
1	1		SS			25
1	1					26
30	1					27
30	1					28
20	1					29
22	1					30
8	1					31
10	1					32
10	1					33
8	1					34
10	1					35
34	1					36
30	1	1				37
30	1					38
20	1					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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
20	1					2
20	1					3
20	1					4
12	1					5
12	1					6
30	1					7
30	1					8
30	1					9
20	1					10
20	1					11
20	1					12
20	1					13
20	1					14
12	1					15
15	1					16
12	1					17
4	1					18
4	1					19
4	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
20	1					29
20	1					30
30	1					31
30	1					32
30	1					33
15	1		STU			34
15	1		STU			35
15	1		STU			36
30	1					37
30	1					38
	1					39
13	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
4		1				2
4	1					3
4	1					4
4	1					5
20	1					6
20	1					7
12	1					8
12	1					9
45	1					10
45	1					11
45	1					12
8	1					13
63	1		STU			14
63	1		STU			15
63	1		STU			16
63	1		STU			17
75	1		STU			18
173			STU			19
75			STU			20
80			STU			21
1						22
13	1					23
13		1				24
13	1					25
13	1					26
13	1					27
10	1		STU			28
	1		GND	1		29
	1		GND	1		30
	1		GND	1		31
2	1		GND	1	1,667	32
10	1					33
10	1					34
34	1					35
12	1					36
12	1					37
10		1				38
6	1					39
6	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
12	1					2
12	1					3
20	1					4
20	1					5
8	1		STU			6
8	1		STU			7
8	1		STU			8
8	1		STU			9
1	1					10
1	1					11
20	1					12
20	1					13
4		1				14
4	1					15
4	1					16
4	1					17
2		1				18
3	1					19
3	1					20
3	1					21
4	1					22
4		1				23
4	1					24
4	1					25
4	1					26
4	1					27
4	1					28
4	1					29
20	1					30
20	1					31
22	1					32
20	1					33
20	1					34
22	1					35
10	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
400	1					3
400	1					4
448	1					5
1	1		AUX			6
29	1		GND	1	28,672	7
10	1					8
10	1					9
30	1					10
30	1					11
10	1					12
5	1					13
8	1					14
8	1					15
10	1					16
8	1					17
22	1					18
20	1					19
10	1					20
17	1					21
448	1					22
400	1					23
19	1		GND	1	19,120	24
1	1					25
20	1					26
20	1					27
3	1					28
3	1					29
3	1					30
4		1				31
4	1					32
4	1					33
4	1					34
4	1					35
4	1					36
4	1					37
3		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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	1					1
	1					2
2	1					3
2	1					4
1	1					5
1	1					6
1	1					7
2		1				8
2	1					9
12	1					10
2		1				11
2	1					12
2	1					13
2	1					14
2	1					15
2	1					16
2	1					17
34	1					18
34	1					19
	1		SS			20
10	1					21
10	1					22
10	1					23
10	1					24
10	1					25
20	1					26
22	1					27
20	1					28
20	1					29
12	1					30
12	1					31
34	1					32
34	1					33
20	1					34
20	1					35
2	1					36
2	1					37
2	1					38
2		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.
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20	1					1
12	1					2
300	1					3
300	1					4
19	1		GND	1	19,120	5
19	1		GND	1	19,120	6
2	1		SS			7
2		1				8
2	1					9
2	1					10
2	1					11
1	1					12
1	1					13
1	1					14
20	1					15
20	1					16
20	1					17
20	1					18
10	1					19
10	1					20
3		1				21
3	1					22
3	1					23
3	1					24
300	1					25
200	1					26
200	1					27
10	1		GND	1	9,561	28
10	1		GND	1	9,561	29
1	1					30
1	1					31
1	1					32
11	1					33
11	1					34
22	1					35
10	1					36
10	1					37
10	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.
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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
12	1					2
20	1					3
20	1					4
10	1					5
10	1					6
6		1				7
6	1					8
6	1					9
6	1					10
20	1					11
	1		SS			12
20	1					13
20	1					14
12	1					15
	1		GND	1		16
20	1					17
30	1					18
12	1					19
12	1					20
13	1		1			21
22	1		1			22
270	1					23
400	1					24
400	1					25
1	1					26
1	1					27
3		1				28
3	1					29
3	1					30
3	1					31
10	1					32
10	1					33
20	1					34
12	1					35
20	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

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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)	
12	1					1
4		1				2
4	1					3
4	1					4
4	1					5
4	1					6
4	1					7
4	1					8
34	1					9
30	1					10
20	1					11
20	1					12
20	1					13
30	1					14
30	1					15
	1					16
20	1		GND	1	20,000	17
22	1					18
12	1					19
12	1					20
12	1					21
22	1					22
20	1					23
37	1					24
20	1					25
20	1					26
20	1					27
20	1					28
25	1		1			29
30	1		1			30
45	1		4			31
5	1		1			32
	1		1			33
12	1					34
12	1					35
20	1					36
20	1					37
10	1					38
11	1					39
	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	1					1
10	1					2
10	1					3
10	1					4
9	1		GND	1	9,145	5
	1					6
4		1				7
4	1					8
4	1					9
4	1					10
30	1					11
34	1					12
20	1					13
20	1					14
4	1					15
4	1					16
4	1					17
	1					18
4		1				19
22	1					20
22	1					21
12	1					22
12	1					23
10	1		STU			24
20	1					25
20	1					26
4		1				27
4	1					28
4	1					29
4	1					30
3		1				31
3	1					32
3	1					33
3	1					34
9		1				35
9	1		STU			36
9	1		STU			37
9	1		STU			38
50	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.
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5	1					1
1	1		GND	1	1,000	2
1	1		GND	1	1,000	3
1	1		GND	1	1,000	4
	1		SS			5
20	1					6
20	1					7
336	1					8
200	1					9
448	1					10
9	1		GND	1	9,145	11
8	1		GND	1	8,230	12
1	1					13
1	1					14
2		1				15
2	1					16
2	1					17
2	1					18
3	1					19
3	1					20
3	1					21
12	1					22
12	1					23
12	1					24
38	1					25
38	1					26
12	1					27
20	1					28
20	1					29
1		1				30
1	1					31
1	1					32
1	1					33
3		1				34
3	1					35
3	1					36
3	1					37
2	1					38
2	1					39
2	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

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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
10	1					4
10	1					5
20	1					6
20	1					7
12	1					8
12	1					9
20	1					10
20	1		REG			11
1		1				12
1	1					13
1	1					14
1	1					15
2		1				16
2	1					17
2	1					18
3	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
10	1					28
20	1					29
20	1					30
20	1					31
20	1					32
3	1					33
3	1					34
3	1					35
3		1				36
3	1					37
3	1					38
3	1					39
2		1				40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

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2	1					1
2	1					2
2	1					3
10	1					4
250	1					5
250	1					6
1	1					7
1	1					8
10	1					9
10	1					10
2	1		STU			11
2	1		STU			12
2	1		STU			13
10	1		GND	1	9,561	14
	1					15
	1					16
	1					17
3	1					18
3	1					19
3	1					20
3		1				21
12	1					22
20	1					23
20	1					24
34	1					25
34	1					26
30	1					27
30	1					28
12	1					29
12	1					30
20	1					31
20	1					32
22	1					33
12	1					34
13	1					35
65	1		STU			36
2	1					37
2	1					38
2	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.
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10	1					1
6		1				2
6	1					3
6	1					4
6	1					5
20	1					6
4		1				7
4	1					8
4	1					9
4	1					10
10	1					11
2		1				12
2	1					13
2	1					14
3	1					15
1		1				16
1	1					17
1	1					18
1	1					19
1	1					20
1	1					21
1	1					22
20	1					23
12	1					24
	1					25
20	1					26
20	1					27
20	1					28
2		1				29
2	1					30
2	1					31
2	1					32
20	1					33
20	1					34
37	1					35
37	1					36
37	1					37
10	1					38
5	1					39
12	1					40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

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12	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
12	1					10
12	1					11
4	1					12
4	1					13
4	1					14
12	1					15
20	1					16
20	1					17
20	1					18
20	1					19
12	1					20
12	1					21
12	1					22
12	1					23
	1		SS			24
20	1					25
20	1					26
	1		SS			27
	1		SS			28
13	1					29
13	1					30
20	1					31
20	1		RAC			32
20	1					33
2	1					34
2	1					35
3	1					36
2		1				37
3	1					38
3	1					39
3	1					40

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

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	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
10	1					13
10	1		STU			14
10	1		STU			15
10	1		STU			16
10	1		STU			17
10	1		STU			18
	1					19
	1					20
	1					21
1	1					22
1	1					23
1	1					24
10	1					25
2		1				26
10	1					27
12	1					28
20	1					29
10	1					30
10	1					31
45	1					32
45	1					33
10	1					34
10	1					35
	1					36
13	1					37
12	1					38
12	1					39
12	1					40

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SUBSTATIONS (Continued)

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12	1					1
		1				2
	1					3
	1					4
	1					5
10	1					6
12	1					7
20	1					8
20	1					9
5		1				10
5	1					11
5	1					12
5	1					13
20	1					14
20	1					15
20	1					16
20	1					17
20	1					18
30	1					19
30	1					20
20	1					21
20	1					22
	1					23
20	1					24
12	1					25
4		1				26
4	1					27
4	1					28
4	1					29
1		1				30
1	1					31
1	1					32
1	1					33
4		1				34
4	1					35
4	1					36
4	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) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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.
200	1					1
200	1					2
448	1					3
300	1					4
200	1					5
1	1		AUX			6
29	1		GND	1	28,672	7
300	1					8
10	1		GND	1	9,561	9
20	1					10
11	1					11
20	1					12
20	1					13
20	1					14
20	1					15
20	1					16
300	1					17
300	1					18
300	1					19
1	1		AUX			20
29	1		GND	1	28,672	21
29	1		GND	1	28,672	22
8	1					23
8	1					24
12	1					25
30	1					26
30	1					27
	1					28
20	1		1			29
20	1					30
15	1		STU			31
15	1		STU			32
15	1		STU			33
15	1		STU			34
12	1					35
12	1					36
22	1					37
22	1					38
6		1				39
6	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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
5	1					3
8	1		1			4
5	1					5
10	1					6
10	1					7
12	1					8
12	1					9
1	1					10
1	1					11
1	1					12
12	1					13
22	1		1			14
12	1					15
						16
70	48	2				17
						18
1048	626	119		3	2	19
						20
76548	1100	63				21
						22
16403	1466	142		10	59	23
						24
						25
5684	965					26
2706	609					27
						28
						29
						30
						31
						32
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						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	1,066,455,330
3	Goods and svcs provided by North/South Ins. Co.	North/South Insurance Co.	Various	6,735,227
4				
5				
6	Generation services	Duke Energy Progress, Inc.	Various	32,702,337
7	Transmission and Distribution services	Duke Energy Progress, Inc.	Various	21,237,560
8	Customer & Market services	Duke Energy Progress, Inc.	Various	3,658,074
9	Other goods and services	Duke Energy Progress, Inc.	Various	3,381,801
10				
11	Generation services	Duke Energy Florida, Inc.	Various	750,964
12	Transmission and Distribution services	Duke Energy Florida, Inc.	Various	3,465,426
13	Customer & Market services	Duke Energy Florida, Inc.	Various	1,148,307
14	Other goods and services	Duke Energy Florida, Inc.	Various	387,606
15				
16	Generation services	Duke Energy Indiana, Inc.	Various	894,207
17	Transmission and Distribution services	Duke Energy Indiana, Inc.	Various	276,927
18	Customer & Market services	Duke Energy Indiana, Inc.	Various	36,613
19	Other goods and services	Duke Energy Indiana, Inc.	Various	98,517
20	**Non-power Goods or Services Provided for Affiliate**			
21	Services provided to DE Business Services, LLC	Duke Energy Business Services LLC	Various	21,086,038
22				
23	Generation services	Duke Energy Progress, Inc.	Various	377,790,268
24	Transmission and Distribution services	Duke Energy Progress, Inc.	Various	22,485,860
25	Customer & Market services	Duke Energy Progress, Inc.	Various	42,602,671
26	Other goods and services	Duke Energy Progress, Inc.	Various	35,774,917
27				
28	Generation services	Duke Energy Florida, Inc.	Various	29,253,698
29	Transmission and Distribution services	Duke Energy Florida, Inc.	Various	19,161,651
30	Customer & Market services	Duke Energy Florida, Inc.	Various	17,887,880
31	Other goods and services	Duke Energy Florida, Inc.	Various	4,974,636
32				
33	Generation services	Duke Energy Indiana, Inc.	Various	79,817,561
34	Transmission and Distribution services	Duke Energy Indiana, Inc.	Various	8,972,502
35	Customer & Market services	Duke Energy Indiana, Inc.	Various	21,218,186
36	Other goods and services	Duke Energy Indiana, Inc.	Various	3,161,396
37				
38	Generation services	Duke Energy Kentucky, Inc.	Various	13,030,245
39	Transmission and Distribution services	Duke Energy Kentucky, Inc.	Various	2,642,573
40	Customer & Market services	Duke Energy Kentucky, Inc.	Various	5,447,988
41	Other goods and services	Duke Energy Kentucky, Inc.	Various	1,796,092
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Other goods and services	Duke Energy Ohio, Inc.	Various	2,942

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/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	Transmission and Distribution services	Duke Energy Ohio, Inc.	Various	390,851
4	Customer & Market services	Duke Energy Ohio, Inc.	Various	78,468
5	Gas Distribution Services	Duke Energy Ohio, Inc.	Various	148,316
6				
7	Gas Distribution Services	Piedmont Natural Gas	Various	11,615,009
8				
9	Other goods and services	Duke Energy One, Inc.	Various	298,772
10				
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16				
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18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Generation services	Duke Energy Ohio, Inc.	Various	286,673
22	Transmission and Distribution services	Duke Energy Ohio, Inc.	Various	7,656,903
23	Customer & Market services	Duke Energy Ohio, Inc.	Various	17,148,151
24	Other goods and services	Duke Energy Ohio, Inc.	Various	583,990
25				
26	Generation services	Piedmont Natural Gas	Various	80,242
27	Transmission and Distribution services	Piedmont Natural Gas	Various	138,311
28	Customer & Market services	Piedmont Natural Gas	Various	124,410
29	Other goods and services	Piedmont Natural Gas	Various	136,429
30				
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42				

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When an employee of the Service Company performs services for a Client Company, costs will be directly assigned or distributed or allocated. For allocated services, the allocation method will be on a basis reasonably related to the service performed. The Service Company Utility Service Agreement prescribes 23 Service Company functions and approximately 20 allocation methods.

Functions and Allocation Methods:

Information Systems
- Number of Central Processing Unit Seconds Ratio/Millions of Instructions per Second
- Number of Personal Computer Workstations Ratio
- Number of Information Systems Servers Ratio
- Number of Employees Ratio

Meters
- Number of Customers Ratio

Transportation
- Number of Employees Ratio
- Three Factor Formula

Electric System Maintenance
- Circuit Miles of Electric Transmission Lines Ratio
- Circuit Miles of Electric Distribution Lines Ratio

Marketing and Customer Relations and Grid Solutions
- Number of Customers Ratio

Electric Transmission & Distribution Engineering & Construction
- Electric Transmission Plant's Construction - Expenditures Ratio
- Electric Distribution Plant's Construction - Expenditures Ratio

Power Engineering & Construction
- Electric Production Plant's Construction - Expenditures Ratio

Human Resources
- Number of Employees Ratio

Supply Chain
- Procurement Spending Ratio
- Inventory Ratio

Facilities
- Square Footage Ratio

Accounting
- Three Factor Formula
- Generating Unit MW Capability Ratio

Power Planning and Operations
- Electric Peak Load Ratio
- Weighted Avg of the Circuit Miles of Electric Distribution Lines Ratio and the Electric Peak Load Ratio
- Sales Ratio
- Weighted Avg of the Circuit Miles of Electric Transmission Lines Ratio and the Electric Peak Load Ratio
- Generating Unit MW Capability Ratio

Public Affairs
- Three Factor Formula
- Weighted Avg of Number of Customers Ratio and Number of Employees Ratio

Legal
- Three Factor Formula

Rates
- Sales Ratio

Finance
- Three Factor Formula

Rights of Way
- Circuit Miles of Electric Transmission Lines Ratio

- Circuit Miles of Electric Distribution Lines Ratio
- Electric Peak Load Ratio

Internal Auditing
- Three Factor Formula

Environmental, Health and Safety
- Three Factor Formula
- Sales Ratio

Fuels
- Sales Ratio

Investor Relations
- Three Factor Formula

Planning
- Three Factor Formula

Executive
- Three Factor Formula

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Transactions presented on this page do not include transactions between Duke Energy Carolinas, LLC and Duke Energy Receivables Finance, LLC.

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