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S.C. SUPREME COURT

THE STATE OF SOUTH CAROLINA
In the Supreme Court

APPEAL FROM THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Public Service Commission Docket Nos. 2018-319-E & 2018-318-E

Duke Energy Carolinas, LLC Appellant-Respondent,

v.

The South Carolina Office of Regulatory Staff, Hasala Dharmawardena, CMC Recycling, Cypress Creek Renewables, LLC, SC Department of Consumer Affairs, Sierra Club, South Carolina Coastal Conservation League, South Carolina Energy Users Committee, South Carolina Solar Business Alliance, Inc., the South Carolina State Conference of the National Association for the Advancement of Colored People, Upstate Forever, Vote Solar, and Walmart, Inc. Respondents,

of whom,

South Carolina Energy Users Committee is Respondent-Appellant.

Duke Energy Progress, LLC Appellant,

v.

The South Carolina Office of Regulatory Staff, Nucor Steel-South Carolina, Cypress Creek Renewables, LLC, SC Department of Consumer Affairs, Sierra Club, South Carolina Coastal Conservation League, South Carolina Energy Users Committee, South Carolina Solar Business Alliance, Incorporated, The South Carolina State Conference of the National Association for the Advancement of Colored People, Upstate Forever, Vote Solar, and Walmart, Inc., .. Respondents.

RECORD ON APPEAL

VOLUME IX OF XIII

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explained in further detail by Witnesses Smith, to allow for such audit, as well as notice and the opportunity for hearing if requested by an interested party.

42. To facilitate the transition to LED outdoor lighting products, the Company proposes, in this Application, to lower the outdoor lighting transition fees charged to customers who move from metal halide ("MH") and high pressure sodium ("HPS") to LED; close mercury vapor ("MV") and incandescent outdoor lighting products on Schedule SL, which serves Greenwood customers, due to technology obsolescence; re-open Schedule PL and merge Schedule GL, which also serves governmental lighting customers, into Schedule PL to improve tariff administration; close HPS fixtures to new installations to lessen the impact on net book value; and close Schedule NL, which is a pilot tariff designed primarily to introduce LED technology, and to discontinue Schedule FL and merge it into Schedules OL and PL. As explained in Witness Cowling's testimony, LED outdoor lighting products are generally preferred by customers as they offer significantly reduced energy use, exhibit longer lifetimes, do not contain mercury, and provide a high color quality, which provides better illumination. Thus, the industry is moving away from HID outdoor lighting products such as MV, HPS and MH, and moving towards LED technology.

REQUEST FOR ACCOUNTING ORDER

43. As part of this Application, the Company requests an accounting order for approval to: (i) continue the deferral for coal ash basin closure compliance costs after the cut-off date for this rate case of December 31, 2018; (ii) establish a regulatory asset to recover the balance of development costs associated with the cancellation of the Lee Nuclear Project; (iii) adopt new depreciation rates effective August 1, 2018, and defer in a regulatory asset the incremental depreciation expense resulting from the new depreciation rates, if and as approved

by the Commission; (iv) continue the deferral for ongoing Grid Improvement costs to be recovered using Phases 1 and 2 rate changes in accordance with the Company's three-year rate plan, or if the Commission does not approve Phases 1 and 2 rate changes then, in the alternative, it approve the deferral of ongoing Grid Improvement costs until the Company's next rate case; and (v) establish reserves for end of life nuclear costs and to begin accruing for the expense related to materials and supplies and a portion of the last core of nuclear fuel in the reactor at the end-of-life of its nuclear generating plants.

44. DE Carolinas requests an accounting order for the continued deferral of coal ash basin compliance costs after the December 2018 cut-off in this case. The Company is requesting the Commission approve a continuation of the deferral, similar to what it approved in Docket No. 2016-196-E for costs not included in this case. Specifically, the Company is requesting approval to defer CCR compliance spend related to ash basin closure beginning January 1, 2019, the depreciation and return on CCR compliance investments related to continued plant operations placed in service on or after January 1, 2019, and a return on both deferred balances at the overall rate of return approved in this case.

45. As a result of the cancellation of the Lee Nuclear Project, the Company is requesting permission to establish a regulatory asset consisting of the balance of development costs adjusted to remove non-depreciable land costs, and estimated expenditures through May 31, 2019. The Company is requesting recovery of the regulatory asset over a 12-year period.

46. DE Carolinas requests approval to (1) adopt new depreciation rates effective August 1, 2018 and (2) to establish a regulatory asset to defer the incremental depreciation expense resulting from the new depreciation rates, if and as approved by the Commission. As explained in the pre-filed testimony of Witness Doss, on June 22, 2018, the North Carolina

Utilities Commission issued an order in Docket No. E-7 Sub 1146 approving DE Carolinas' depreciation rates based on the rates set forth in the original, with specific adjustments. The Company incorporated these adjustments in a revised study, which resulted in an approximate annual increase in depreciation expense of \$40 million on a system basis (\$10 million on a South Carolina retail basis) when applied to end of 2017 plant balances. DE Carolinas respectfully requests that the Commission issue an accounting order approving the depreciation study and adopting and implementing the new depreciation rates, which includes the aforementioned adjustments. In addition, the Company is seeking permission to establish a regulatory asset to defer the incremental depreciation expense resulting from the new depreciation rates, if and as approved by the Commission. The costs the Company seeks to defer are approximately \$9 million on a South Carolina retail basis, estimated through May 31, 2019. The deferred costs to be recorded on the Company's accounting records will be based on actual costs. The Company proposes to amortize the regulatory asset over a three year period.

47. DE Carolinas also requests an accounting order for approval to defer costs associated with the incremental grid investments placed in service after December 31, 2018, until those costs are included base rates, either through the Phase 1 or 2 rates or a subsequent general rate case, incurred in connection with the Grid Improvement Plan. Specifically, the Company seeks to defer the incremental O&M, depreciation expense and property taxes associated with the capital assets installed as part of its Grid Improvement Plan, as well as the carrying cost on the investment and on the deferred costs at the Company's weighted average cost of capital. The Company proposes to recover the deferred costs in accordance with its proposed three-year rate plan request, allowing for pre-defined rate changes, Phases 1 and 2, for these investments in 2020 and 2021, respectively. For any costs not included in the Phase 1 or Phase 2 rate changes,

the Company to defer these costs until its next rate case. In the alternative, if the Commission does not approve the Company's three-year rate plan request, the Company asks the Commission to approve the ongoing deferral of Grid Improvement Plan costs until the Company's next rate case. Without this accounting treatment, costs incurred for grid improvement will negatively impact the Company's financials on a project by project basis since they would not be captured in rates, and unlike capital projects of similar financial magnitude, the Company's will not have the opportunity to fully capture these costs absent the requested deferral.

48. Finally, DE Carolinas requests an accounting order for approval to establish a reserve for end of life nuclear costs. Currently, there are some end-of-life costs at a nuclear plant that are not captured in a decommissioning study (e.g., the expense to write off the materials and supplies in inventory at the time of decommissioning that have little or no salvage value). The Company is proposing to create a reserve to start accruing for these end-of-life expenses and, therefore, create a better matching of cost and benefit for ratemaking purposes. The annual accrual amount will be determined by dividing the projected inventory balance at the end of each unit's life by the number of years remaining in the unit's life and summing this result for the Company's three nuclear plants. In this proceeding, the Company is requesting an annual accrual amount of approximately \$5 million as allocated to South Carolina retail. The annual accrual amount can be reviewed and adjusted, if needed, in each future general rate case before the end of the plant's life. The Company is also proposing to create a reserve to start accruing for the expense related to a portion of the last core of nuclear fuel in the reactor at the end-of-life of its nuclear generating plants and, therefore, create a better matching of cost and benefit for ratemaking purposes. The annual accrual amount will be determined by dividing the projected remaining value of the last core of nuclear fuel at the end of each unit's life by the number of

years remaining in the unit's life and summing this result for the Company's three nuclear plants. In this proceeding, the Company is requesting an annual accrual amount of \$2 million as allocated to South Carolina retail. The annual accrual amount can be reviewed and adjusted, if needed, in each future general rate case before the end of the plant's life. The reserves, once they are created, will be included as an offset to rate base in the cost of service.

REQUESTED RATES

49. Copies of the rates now in effect are attached as **Exhibit A**. The proposed schedules of rates and charges, attached to this Application as **Exhibit B**, are filed in accordance with the provisions of S.C. Code Ann. §§ 58-27-860, 865, 870. The proposed rates set forth in **Exhibit B** include a base combined fuel, environmental and the Public Utility Regulatory Policies Act ("PURPA") purchased power capacity cost factors of 1.8769 cents per kWh for the residential class, 1.8639 cents per kWh for the general service/lighting class, and 1.8161 cents per kWh for the industrial class.¹⁴ These base combined fuel, DERP Avoided Capacity and PURPA Avoided Capacity cost factors are not being adjusted in this case and are equal to the total of the fuel and environmental cost factors by customer class approved by the Commission in Docket No. 2017-3-E as well as all other riders approved by the Commission. The rates set forth in **Exhibit B** are designed to increase annual revenues from South Carolina retail operations by a net amount of approximately \$168¹⁵ million or a 10 percent average increase in rates, based on the test year of the twelve month period ending December 31, 2017 adjusted for known changes. The proposed revenue increase is distributed among classes of customers by

¹⁴ Due to timing, these rates exclude the effect of gross receipts tax, utility assessments and were calculated using the base fuel cost factors approved in Docket No. 2017-3-E and effective October 1, 2017 through September 30, 2018; as the effects of fuel are netted, this does not affect the revenue requirement being requested in this Application.

¹⁵ The net annual revenue increase includes the impact of the return of excess deferred income taxes through the EDIT Rider of approximately \$62 million.

increasing the rate schedules as follows: 12.1 percent for the residential class, 8.8 percent for the general service/lighting class, and 4.1 percent for the industrial class. The different percentage increases for customer classes reflect the allocation of the rate increase based on the overall rate of return. The Company proposes to modify certain rate schedules to reflect more accurately the cost of service and to consolidate and cancel certain rate schedules.

50. The rates set forth in **Exhibit A** are unjust and unreasonable because they do not allow the Company the opportunity to earn a fair rate of return. In Order No. 2013-661, the rates were set based on a 10.2 percent return on common equity. The overall rate of return on rate base was set at 7.89 percent. During the twelve month period ended December 31, 2017, as adjusted for known changes, the rate of return on South Carolina retail rate base, as shown on **Exhibit C**, was only 4.07 percent.

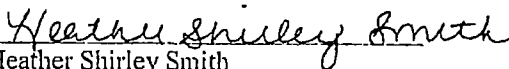
51. The exhibits attached to this Application are as follows:

- **Exhibit A.** The schedule of the Company's electric rates and charges in effect and on file with the Commission at the time of filing this Application, which the Company seeks to increase.
- **Exhibit B.** The schedules of electric rates and charges the Company proposes to put into effect on June 1, 2019.
- **Exhibit C.** Current tariffs highlighting all changes requested in the proposed schedules.
- **Exhibit D.** The financial data for the 12-month period ended December 31, 2017 filed in compliance with 26 S.C. Code Ann. Regs. 103-823.
- **Exhibit E.** The schedules of Phase 1 and Phase 2 rate changes to reflect rate changes to recover known and measurable costs being incurred for the proposed Grid Improvement Plan.

DE Carolinas proposes that all accounting and pro forma adjustments set forth in the attached exhibits be adopted in this proceeding for ratemaking and reporting purposes.

WHEREFORE, DE Carolinas requests the Commission approve the electric rates and charges filed as **Exhibit B**, effective June 1, 2019, as indicated in the tariffs filed in this case, as well the rates filed in **Exhibit E**, effective 12 and 24 months subsequent to the rates and charges in **Exhibit B** going into effect; that the Commission approve the Company's accounting order and program approval requests described in this Application; and that the Commission grant DE Carolinas such further, different, or other relief as may be just and reasonable.

This the 8th day of November, 2018.


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VERIFICATION

STATE OF SOUTH CAROLINA)
)
COUNTY OF GREENVILLE)

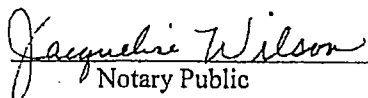
KODWO GHARTEY-TAGOE, being first duly sworn, deposes and says:

That he is President of Duke Energy Carolinas-South Carolina; that he has read the foregoing Application, and knows the contents thereof; that the same is true as to matters stated therein on information and belief, and as to those matters he believes it to be true.


Kodwo Gharthey-Tagoe

Sworn to and subscribed before me

This 6th day of November, 2018.


Notary Public

My Commission Expires: 8-27-2028



Jacqueline Wilson
NOTARY PUBLIC
State of South Carolina
My Commission Expires
August 27, 2028

STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2018-319-E

IN THE MATTER OF:

Application Duke Energy Carolinas, LLC
For Adjustments in Electric Rate Schedules
and Charges

PETITION TO INTERVENE

The South Carolina Energy Users Committee ("SCEUC") hereby petitions the South Carolina Public Service Commission ("Commission") pursuant to R.103-836 of the Commission's rules and regulations to intervene and to be made a party of record in the above-captioned docket. In support of this Petition, SCEUC would allege as follows:

1. That on November 8, 2018, Duke Energy Carolinas, LLC ("Duke Energy" or the "Company") filed an application with the Commission pursuant to S.C. Cod Ann. §§ 58-27-820 and 58-27-870 and 26 S.C. Code Ann. Regs 103-303 and 103-823 seeking, *inter alia*, authority to adjust, change and increase its retail electric rates, charges and tariffs which, according to the application, would increase annual revenues by approximately 10% or \$168 million.

2. That SCEUC is an association organized in the State of South Carolina, consisting of large industrial consumers of energy which are engaged in various manufacturing enterprises throughout the State.

3. That a number of members of SCEUC purchase and consume substantial amounts of electricity from Duke Energy.

4. That SCEUC and its members have a direct and material interest in the issues to be addressed and resolved by the Commission in this docket and the interests of its members are not adequately represented by the current parties to this proceeding.

5. That given the state of the record at this stage of the proceedings, SCEUC lacks sufficient information to fully develop and state its position in this proceeding at this time.

6. That granting SCEUC's request to be made a party of record in this proceeding is in the public interest, is consistent with the policies of the Commission in encouraging maximum public participation in issues before it, and should be allowed so that a full and complete record addressing its views and concerns can be developed.

7. That in accordance with Rule R. 103-804 (S) of the Commission's Rules of Practice and Procedure, Petitioner is represented by counsel in this proceeding:



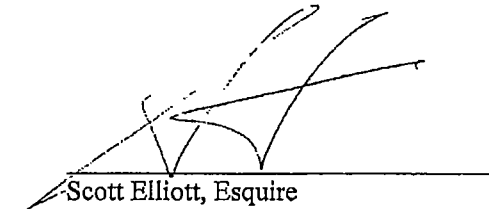
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WHEREFORE, Petitioner prays for the following relief:

- a. That this Petition to Intervene be accepted and that Petitioner be made a party of record;

- b. That Petitioner be allowed to participate fully in this proceeding and take such positions as it deems advisable; and
- c. For such other and further relief as is just and proper.

P.B.



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*Attorney for the South Carolina
Energy Users Committee*

Columbia, South Carolina
January 10, 2019

CERTIFICATE OF SERVICE

The undersigned employee of Elliott & Elliott, P.A. does hereby certify that (s)he has served below listed parties with a copy of the pleading(s) indicated below by mailing a copy of same to them in the United States mail, by regular mail, with sufficient postage affixed thereto and return address clearly marked on the date indicated below:

RE: Application Duke Energy Carolinas, LLC for Adjustments
in Electric Rate Schedules and Charges

DOCKET NO.: 2018-319-E

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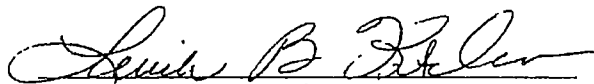
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PLEADING:

PETITION TO INTERVENE BY SOUTH CAROLINA
ENERGY USERS COMMITTEE

January 10, 2019



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Action Item 8

**PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
COMMISSION DIRECTIVE**

ADMINISTRATIVE MATTER	☐	DATE	<u>January 30, 2019</u>
MOTOR CARRIER MATTER	☐	DOCKET NO.	<u>2018-319-E</u>
UTILITIES MATTER	☒	ORDER NO.	<u>2019-90</u>

THIS DIRECTIVE SHALL SERVE AS THE COMMISSION'S ORDER ON THIS ISSUE.

SUBJECT:

DOCKET NO. 2018-319-E - Application of Duke Energy Carolinas, LLC for Adjustments in Electric Rate Schedules and Tariffs - Staff Presents for Commission Consideration the Petition to Intervene Filed on Behalf of South Carolina Energy Users Committee.

COMMISSION ACTION:

Grant the Petition to Intervene of South Carolina Energy Users Committee.

PRESIDING: Randall

SESSION: Regular

TIME: 2:00 p.m.

	MOTION	YES	NO	OTHER
ELAM	☐	☒	☐	
ERVIN	☐	☒	☐	
HAMILTON	☐	☒	☐	
HOWARD	☒	☒	☐	
RANDALL	☐	☒	☐	
WHITFIELD	☐	☒	☐	
WILLIAMS	☐	☒	☐	

(SEAL)



RECORDED BY: J. Schmieding

STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2018-319-E

IN THE MATTER OF:	)	
	)	
Application Duke Energy Carolinas, LLC	)	SOUTH CAROLINA ENERGY
For Adjustments in Electric Rate Schedules	)	USERS COMMITTEE
and Tariffs	)	AMENDED BRIEF

Duke's rate request is excessive. Duke is entitled to the lowest reasonable rate. Duke should be granted recovery of only those costs necessary to benefit its ratepayers.

PRECONSTRUCTION COSTS

Duke Energy Carolinas, LLC ("Duke") elected to recover its nuclear plant preconstruction costs under the Base Load Review Act, S. C. Code Ann. Sections 58-33-210 et seq. ("BLRA" or "Act") The General Assembly has amended the BLRA in a manner that now prohibits Duke recovery of its preconstruction costs. Accordingly, Duke's request for recovery of its nuclear preconstruction costs should be denied.

In its application filed November 8, 2018, Duke requests a rate increase pursuant to S.C. Code Ann. Sections 58-27- 820 and 58-27-870. As a part of its application for a rate increase, Duke seeks recovery of \$125 million in preconstruction costs from its abandoned Lee Nuclear Station project begun in 2007. With a return on the recovery of preconstruction costs, Duke's ratepayers would pay \$20 million annually over 12 years for Duke's abandoned project to construct nuclear plants at its Lee Station.

The General Assembly amended the BLRA in June of 2018 to prohibit the Commission from considering any request made pursuant to the BLRA in any docket not then pending before the Commission. Act R287, H4375. Duke concedes that it was prohibited from seeking recovery of its preconstruction costs pursuant to S.C. Code Ann Section 58-33-225(G) of the BLRA. (Fallon prefiled direct testimony p. 25, ll. 6-15) To avoid the prohibition of the BLRA, Duke seeks recovery of its preconstruction costs by relying on statutes predating and unrelated to the BLRA.

Facts As To Preconstruction Costs

In 2007, Duke elected to file its request under S.C. Code Ann. Section 58-33-225 of the BLRA for approval of its decision to incur preconstruction costs associated with its Lee Nuclear Station. By Order No. 2008-417 in Docket No. 2007-440-E, the South Carolina Public Service Commission ("Commission") held that Duke's decision to incur preconstruction costs was reasonable and prudent. The Commission also authorized Duke to incur the South Carolina allocable share of \$230 million in preconstruction costs through December 31, 2009. Order No. 2008-417 did not rule on the prudence or recoverability of specific items of cost.

In 2011, Duke filed an amended project development application for approval of its decision to incur additional preconstruction costs to those previously authorized Order No. 2008-417. While Duke had requested authority to incur an \$229 million in preconstruction costs in Docket No. 2011-20-E, the Commission only authorized Duke to incur an additional \$120 million in costs, including AFUDC. Order No. 2011-454 at page 17. Order No. 2011-454 was not a blank check as Duke argues. Order No. 2011-454 approved a settlement agreement which the Commission characterized as follows: "the settling parties agreed that:

(i) only the absolute minimum amount of dollars necessary to keep the nuclear option available should be spent and that the expenditures from January 1, 2011, through June 30, 2012, should be no more than \$75 million without AFUDC and not to exceed \$120 million including AFUDC; (ii) the prudency determination in this proceeding will only apply to the expenditure of these funds, and in any proceeding to recover costs, the Company must show that the activities it undertook meet the requirements set forth in the Settlement Agreement....” Order No. 2011-454, page 4. In approving the parties’ settlement, the Commission ordered that its prudency determination applied “only to the South Carolina allocable share of the additional pre-construction costs of \$75 million without AFUDC, not to exceed \$120 million with AFUDC for the period of January 1, 2011 through June 30, 2012.” Order No. 2011-454 at page 17.

By June 30, 2012, Duke had spent \$251 million of the \$350 million authorized by the Commission.¹ (Fallon prefiled direct at p. 32, ll. 14-18) Subsequent to June 30, 2012, Duke incurred an additional \$271 million in preconstruction costs through September 30, 2018. (Fallon prefiled direct testimony at p. 33, ll. 5-7) By June 30, 2012, Duke had incurred \$68 million in AFUDC. (Exhibit No. 19) Subsequent to June 30, 2012, Duke incurred an additional \$180 million in AFUDC through December 31, 2017 for a total of \$248 million in AFUDC costs. (Fallon prefiled direct testimony at p. 26, l. 8 – p. 27, l. 2) Duke total system balance of preconstruction costs are \$518 million. Of the total balance, Duke is seeking recovery of the South Carolina allocable share of \$125 million. Duke seeks annual recovery from its South

¹ In compliance to Order Nos. 2008-417 and 2011-454, Duke expended \$251 million in preconstruction costs through June 30, 2012. Pursuant to the BLRA, Duke would have been entitled to recovery of \$60 million.

Carolina ratepayers of \$20 million comprised of amortization expense, over 12 years, of \$11 million, and a net of tax return of \$9 million on the unamortized balance. (Smith prefiled direct p. 19, l.6 – p. 20, l. 2)

The preconstruction costs for which Duke seeks recovery are not used and useful to provide electricity. (Morgan prefiled direct p. 6, l11-13) Duke concedes as much. See Application para. 17, p. 10 describing the cancelled nuclear project.

Argument As To Preconstruction Costs

The South Carolina General Assembly is vested with the constitutional authority to regulate publicly owned utilities. Article IX, Section 1 of the South Carolina Constitution reads as follows:

Regulation of common carriers, publicly-owned utilities and privately-owned utilities serving the public. The General Assembly shall provide for appropriate regulation of common carriers, publicly owned utilities, and privately owned utilities serving the public as and to the extent required by the public interest. (1970 (56) 2690; 1971 (57) 47).

Thus the South Carolina Constitution requires the General Assembly to protect the public interest in carrying out its responsibilities with respect to public utility regulation.

Rate-making is a legislative function. Our Supreme Court has held that,

“[i]t has been held that rate making is not a judicial function...but is a legislative one, whether exercised by the legislature directly or by an administrative body under delegated authority, although subject to review by the courts as to legality and reasonable of its exercise.... It operates prospectively, and necessarily implies a range of legislative discretion, and ordinarily the legislative determination within the scope of discretion is conclusive.” Berry v. Lindsay, 256 S.C. 282, 290, 182 S.E.2d 78, 82 (1971)

This Commission has been charged with the authority to set rates that are just and reasonable. S.C. Code Ann. § 58-3-140(A).

In enacting the BLRA, the General Assembly provided Duke with benefits not available under traditional forms of rate making such as provided in S.C. Code Ann. Sections 58-27-820 and 870.² In particular, S.C. Code Ann. Section 58-33-225 provided Duke the opportunity to elect to apply to the Commission for a project development order which affirms the utility's decision to incur preconstruction cost for a propose nuclear plant.

Historically, having made the decision to build a nuclear plant, a utility would be required to request a prudency determination of its decision to construct the plants as a part of a rate case after having begun construction of the nuclear plant and having expended hundreds of millions of dollars. Thereafter, in each successive rate case to recover its nuclear construction costs, the utility would have to justify its decision to build the nuclear plant. Electing to recover its nuclear costs pursuant to S.C. Code Ann. Sections 58-27-820 and 870 created the risk to Duke that in each rate case filed to recover its nuclear construction costs (including preconstruction costs), the Commission would determine that Duke's decision to construct the plants or to continue to construct the plants was imprudent after Duke's expenditure of hundreds of millions of dollars.

The BLRA eliminated the risk of an after the fact determination of prudency by affirming the decision to incur the preconstruction costs set out in SC Code Ann. Section 58-33-220(12). The BLRA provided that the prudency of the decision to incur preconstruction

² The title of the BLRA provides in part that the purpose of the Act was to "TO AMEND THE CODE OF LAWS OF SOUTH CAROLINA, 1976, BY ADDING ARTICLE 4 TO CHAPTER 33, TITLE 58 SO AS TO ENACT THE 'BASE LOAD REVIEW ACT' BY REVISING PROCEDURES FOR APPROVING COSTS ASSOCIATED WITH THE ADDITION OF BASE LOAD GENERATION PLANTS....." Emphasis added.

costs may not thereafter be challenged.³ The upfront prudency determination permitted by the BLRA is invaluable.

Subsequent to the abandonment of the nuclear plants under construction in Jenkinsville, S. C. by SCE&G, the General Assembly took a hard look at the BLRA and after much study, amended the BLRA to prevent its future application. In particular, the General Assembly prohibited the Commission from accepting an application for relief under the BLRA in any future proceeding. R287, H4375 was enacted which provides:

SECTION 2.A. As of the effective date of this act, the Public Service Commission must not accept a base load review application, nor may it consider any request made pursuant to Article 4, Chapter 33, Title 58 other than in a docket currently pending before the Commission.

R287, H4375 became effective June 28, 2018. The application in the instant docket was filed November 8, 2018. The Commission was precluded from considering a request for recovery of preconstruction costs pursuant to the BLRA.

The General Assembly's repeal of the BLRA was in all respects lawful and constitutional. The preconstruction costs for which Duke seeks recovery are not used and useful for utility purposes. In repealing the provisions of the BLRA which authorized recovery of preconstruction costs, the General Assembly intended to prohibit recovery of those nuclear costs which were not used and useful. A similar statute was upheld by the United States Supreme Court in *Duquesne Light Co. V. Barasch*, 488 U. S. 299 (1989); see SCAG Opinion September 26, 2017 at pages 43-46.

³ The prudency of individual items of cost or decisions subsequent to the issuance of a project development order may be challenged. S.C. Code Ann. Section 58-33-2225(E).

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providing service to the public. The generating units that burned the coal and produced the ash that is now being remediated provided electricity to DEC customers in both South Carolina and North Carolina. The costs of building and operating those plants have been shared by the customers of both states on a fair and equitable basis since the plants were brought on line, in most cases decades ago. The Commission's decision in this case that certain of the costs associated with those plants should now not be borne by the South Carolina customers who benefited from the electricity produced by those plants is unsupported by either law or fact. The inequity of the Commission's decision in this case is amplified by the fact that North Carolina customers are paying for these same types of costs for South Carolina sites.

As set forth more fully below, the Commission's decision violates constitutional protections afforded by the South Carolina and United States Constitutions; suffers from multiple errors of law; is founded on multiple factual errors that render the decision clearly erroneous in view of the reliable, probative, and substantial evidence on the whole record; and is arbitrary and capricious, or characterized by abuse of discretion or clearly unwarranted exercise of discretion. Accordingly, the Commission's decision on Coal Ash Costs should be reconsidered, and DEC should be allowed to recover the full amount of those costs.

1. The Commission's Decision Violates Multiple Provisions of the South Carolina and United States Constitutions.

The rates established by the Commission must provide the utility with the opportunity to recover its reasonable operating expenses, as well as provide a fair and reasonable return on the investments made by the company in providing utility service to its customers. *Southern Bell & Tel. Co. v. Pub. Serv. Comm'n*, 270 S.C. 590, 600 (1978); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 604 (1944). Although the burden of proof in showing the

reasonableness of a utility's costs underlying its request to adjust rates ultimately rests with the utility, the South Carolina Supreme Court has concluded that the utility is entitled to a presumption that its expenses are reasonable and were incurred in good faith. *Hamm v. S.C. Pub. Serv. Comm'n*, 422 S.E.2d 110, 309 S.C. 282 (1992) (internal citations omitted). Other parties are therefore required to produce evidence that overcomes both this presumption and any evidence the utility has proffered that further substantiates its position. *See Utilities Servs. of S.C., Inc. v. S.C. Office of Regulatory Staff*, 392 S.C. 96, 110, 708 S.E.2d 755, 762-63 (2011).

In this proceeding, no evidence was presented to the Commission that overcame the presumption of the reasonableness and good faith of the DEC Coal Ash Costs. The basis of the Commission's decision was that certain of the Coal Ash Costs incurred at generating plants in North Carolina were required by provisions of the North Carolina Coal Ash Management Act ("CAMA"), and, for that reason alone, that portion of the Coal Ash Costs should not be recovered from South Carolina customers. No evidence was presented that the Coal Ash Costs were imprudent or unreasonable, and it is undisputed that South Carolina customers benefited from the electricity generated at the plants located in North Carolina from which the purported CAMA costs in question arise. Accordingly, the Commission's denial of these costs violates several constitutional provisions.

First, the Commission's decision amounts to an unconstitutional taking under the United States Constitution and South Carolina Constitution, which both prohibit the government from taking property without just compensation. *See* U.S. Const. art. V; U.S. Const. art. XIV; S.C. Const. art. I, § 13.

Second, because the Commission's decision lacks any cognizable legal basis for denying Coal Ash Costs and is predicated on clearly erroneous factual conclusions, it deprives DEC of

substantive due process under the Fourteenth Amendment of the United States Constitution and Article I, Section 3 of the South Carolina Constitution.

Finally, the Commission's denial of DEC's Coal Ash Costs based on the "sovereignty" of the State of South Carolina (Order No. 2019-341, pp. 50-52) violates the Commerce Clause of the United States Constitution, which prevents states from engaging in economic discrimination and burdening the flow of interstate commerce. U.S. Const. art. I, § 8.

2. The Commission's Decision Suffers from Multiple Errors of Law.

As discussed above, no evidence was presented in this proceeding that the Coal Ash Costs at issue were imprudent or unreasonable, and it is undisputed that South Carolina customers benefited for decades from the electricity generated at the plants located in North Carolina from which the purported CAMA costs in question arise. Since South Carolina customers have undisputedly received the low-cost power from these North Carolina plants for decades under the "regulatory compact" that compels DEC to serve them, the Commission's order denying the cost to comply with North Carolina environmental compliance laws violates the doctrine of unjust enrichment. Additionally, in deciding to provide South Carolina customers with low-cost electricity from its North Carolina coal-burning plants, DEC reasonably relied on the representation and ongoing presumption that it would be allowed to recover the reasonable and prudent costs associated with generation of that power and the byproducts thereof, including environmental compliance costs. Since DEC has reasonably relied on this fact to its detriment, the Commission's order denying these costs violates the doctrine of equitable estoppel.

3. The Commission's Decision Is Clearly Erroneous in View of the Reliable, Probative, and Substantial Evidence on the Whole Record.

In denying Coal Ash Costs in the amount suggested by ORS witness Wittliff, the Commission relied upon the following factual errors:

Error No. 1 (Riverbend): The Commission disallowed \$316,680,585, which accounted for all coal ash compliance costs incurred to-date at the Riverbend plant, based upon witness Wittliff's incorrect testimony that the CCR Rule and other regulatory requirements do not require any remediation at Riverbend.

Error No. 2 (Dan River): The Commission disallowed \$167,426,449 in coal ash remediation costs based on witness Wittliff's testimony that CAMA's alleged accelerated closure timeline caused the Company to incur additional costs notwithstanding that witness Wittliff admitted that his calculations for this disallowance were based on an incorrect closure date.

Error No. 3 (Multiple Sites): The Commission based its disallowances for the alleged accelerated timeline costs for these sites on witness Wittliff's calculation using the "weighted average of engineering and planning as a percentage of total project costs", which Wittliff admitted were imprecise estimates and not actual costs.

Error No. 4 (Legal Fees): The Commission tied its disallowance of certain legal fees to the assertion that DEC should be prevented "from charging its customers with any legal costs or expenses flowing from or related to its guilty plea of criminal negligence" without regard to undisputed evidence that no such costs or expenses were included for recovery.

4. The Commission's Decision is Arbitrary and Capricious.

"A decision is arbitrary if it is without a rational basis, is based alone on one's will and not upon any course of reasoning and exercise of judgment, is made at pleasure, without adequate determining principles, or is governed by no fixed rules or standards." *Deese v. S.C. State Bd. of Dentistry*, 286 S.C. 182, 184–85, 332 S.E.2d 539, 541 (1985). Where, as here, the Commission makes no findings of fact or conclusions of law, South Carolina courts have found orders to be arbitrary and capricious. As the South Carolina Supreme Court has held, "a recital of conflicting testimony followed by a general conclusion is patently insufficient to enable a reviewing court to address the issues." *Able Communications, Inc. v. South Carolina Pub. Serv. Comm'n*, 290 S.C. at 411, 351 S.E.2d at 152.

With respect to its decision to disallow certain of the Coal Ash Costs, the Commission did not, in its Order, make any competent findings of fact or conclusions of law to support its decision, nor did it articulate any fixed rules or standards under which the Commission's order can be judged. In the absence of any such findings, a court would be compelled to find that the

Commission's Order denying Coal Ash Costs is without a rational basis; is based alone on the Commission's own will; and is not governed by any fixed rules or standards. For all of these reasons, the Order with respect to the Coal Ash Costs, is arbitrary and capricious and amounts to reversible error.

B. Treatment of Deferrals.

The Commission's treatment of DEC deferrals violates the Company's right to recovery of the prudently incurred expenses of providing service to its customers. Pursuant to the principles established in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), DEC has a constitutional right to a reasonable opportunity to recover its prudently incurred costs of providing service. In this proceeding, it was undisputed that the deferred costs were both prudently incurred and used and useful. The Commission's decision to refuse to allow DEC to recover any return on substantial portions of its deferrals, combined with the adoption of excessively long amortization periods for the deferrals, will prevent DEC from recovering its expenses in a manner that is required by the constitution.

Following are the specific deferral rulings by the Commission that are unlawful for the reasons stated in this section.

- Carolinas West Control Center (Adjustment #7). The Order requires the amortization of deferred depreciation expense totaling \$1.4 million over thirty years with no return allowed during the deferral or amortization periods.
- W.S. Lee Combined Cycle Facility (Adjustment #13). The Order requires the amortization of deferred depreciation, O&M, and property tax expenses totaling \$7.1

million over thirty-nine years with no return allowed during the deferral or amortization periods.

- Environmental Costs (Adjustment #18). The Order requires the amortization of deferred depreciation expenses totaling \$2.1 million over five years without allowing any return during the deferral or amortization period.
- Advanced Metering Infrastructure (Adjustment #19). The Order requires the amortization of deferred depreciation expense totaling \$12 million over fifteen years with no return allowed during the deferral or amortization periods.
- Customer Connect (Adjustment #30). The Order requires the amortization of deferred O&M costs totaling \$3.2 million associated with implementation of its Customer Connect information system over a period of three years with no return allowed during the deferral or amortization periods.
- Grid Improvement Costs (Adjustment #35). The Order requires the amortization of deferred depreciation, O&M and property tax expenses totaling \$2.8 million over a period of five years with no return allowed during the deferral or amortization periods.

The Commission's ruling on DEC deferrals is arbitrary and capricious because it is inconsistent with prior rulings allowing DEC to establish the deferral accounts. In Order No. 2016-489 and Order No. 2018-552 the Commission approved the establishment by DEC of the deferral accounts at issue in this proceeding. Those orders allowed DEC to accrue a weighted average cost of capital ("WACC") return on the deferred balance as has been the practice of the Commission in the past. Those orders also reserved questions of the prudence of the underlying costs for a subsequent rate proceeding. In this case, no party contested the prudence of the deferred expenses and the Commission has not made any finding that the expenses were

imprudent. In refusing to allow DEC to recover a WACC return on a substantial portion of the deferred balances, the Order is inconsistent with the Commission's prior rulings in Orders 2016-489 and 2018-552. The change in treatment is arbitrary and capricious and in violation of law. The Commission should reconsider its decision to refuse to allow the recovery of a return on the full amount of the deferred balances.

The Commission's ruling on the DEC deferrals is arbitrary and capricious because it fails to recognize that the deferred accounts that it allowed DEC to establish in Order No. 2016-489 and Order No. 2018-552 represented money that DEC spent to provide service to its customers and which DEC was required to raise from debt and equity investors. Because debt and equity investors must be compensated for the time value of their money, DEC incurs substantial costs associated with the funds in the deferred accounts. By denying DEC any recovery on the deferred funds and requiring the funds be recovered over extended periods of time, the Order fails to allow DEC its constitutionally protected opportunity to recover its costs of providing service to the public. Moreover, there is no accounting guidance to support the treatment proposed by the ORS and adopted by the Commission of separating the deferred balances into two categories, deferred operating expenses and deferred capital costs. These financing costs (the return on the deferred costs) are real costs that the Company incurred and to disallow recovery of these costs during the deferral period or the amortization period would be to disallow prudently incurred costs.

The Commission also ignored the fact that the ORS' logic is misplaced and inconsistent because there are carrying costs on regulatory liabilities that the ORS is willing to accept when they benefit customers. (*Id.* at 659-7.) Indeed, during the hearing, the Commission heard testimony that customers earn a return on a number of costs that they "pre-pay the Company."

See Tr. Vol. 5, p. 1116-18 (Company witness Doss testified that customers would receive a return on the costs being held in the end-of-life nuclear reserve); Tr. Vol. 4, p. 731 (customers are paid interest on deposits); Tr. Vol. 7, p. 1707 (Accumulated deferred income taxes ("ADITs") collected from customers are included in rate base as a credit and thus customers are earning a return on that balance as conceded by ORS witness Payne); *Id.* at 1708 (the Company is proposing that customers earn a return on the EDIT balance which would not have existed if the Commission had not ordered that deferral.) As a further example, the treatment in the Order of the effect of the Tax Cuts and Jobs Act ("TCJA") is inconsistent with the treatment of deferred expenses, demonstrating that the Commission's rulings on deferrals are arbitrary and capricious. Income taxes are an operating expense like depreciation, O&M and property taxes. Deferred income taxes result from the timing difference between when the Company collects taxes in rates and actually pays the taxes. Because the funds are collected from customers before they are paid to the U.S. Treasury, a regulatory liability is created instead of a regulatory asset. The regulatory liability is used as an offset to rate base resulting in substantial savings to customers. If the logic of the position recommended by the ORS, and accepted by the Commission, for deferrals was applied to the impact of the TCJA, rates would significantly increase. The inconsistency of the treatment of deferrals and the TCJA regulatory liability is arbitrary and capricious and supports DEC's request for reconsideration of the Order.

C. Return on Equity.

The Commission's decision to set DEC's revenue requirements using a return on equity ("ROE") of 9.5% is arbitrary and capricious and should be reconsidered. The undisputed evidence establishes that 9.5% is well below authorized ROEs for the Company's peers in the Southeast with which the Company competes for equity capital. The higher ROEs awarded to

the Company's peers reflect the risks attendant upon owning and operating vertically integrated utilities, including nuclear generation, and a 9.5% ROE simply does not adequately account for those risks. Additionally, the following are errors and inconsistencies that demonstrate that the decision on ROE is arbitrary and capricious and should be reconsidered.

- The Order was issued just months after the Commission issued Order No. 2018-804 in consolidated Docket Nos. 2017-207-E, 2017-305-E and 2017-370-E. In that consolidated proceeding, the Commission was asked to make a determination of the cost of equity for SCE&G assuming that the merger of its parent SCANA and Dominion Energy was approved. SCE&G presented the testimony of Robert Hevert, the same witness called by DEC to testify about ROE issues in this proceeding. Not surprisingly, the testimony of Hevert was similar in the two cases. However, in the SCE&G proceeding, the Commission made the following ruling on the ROE issue:

In short, the Commission finds that there is ample evidence and reason to conclude that the analyses conducted by Mr. Hevert are accurate and reliable estimates of SCE&G's cost of equity. The Commission further finds that it is appropriate and reasonable to consider a range of estimates under various methodologies in order to more accurately estimate SCE&G's cost of equity. Accordingly, the Commission rejects Mr. Baudino's analysis as flawed and incomplete, concludes that the Company's current cost of equity most likely ranges between 10.25% and 11% as determined by Mr. Hevert, and that the most likely point estimate of the costs of equity is 10.75%, assuming the merger is approved.

Order No. 2018-804 at pp. 89-90.

- The ROE ruling by the Commission in Order No. 2018-804 was one of the issues addressed in petitions for reconsideration filed by intervenors. In Order No. 2019-122, issued on February 12, 2019, the Commission rejected their arguments asking for reconsideration on the ROE issue:

The decision to adopt Mr. Hevert's return on equity calculation is supported by the evidence and is neither capricious nor arbitrary. *See S. Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n*, 270 S.C. 590, 598, 244 S.E.2d 278, 282 (1978) (finding that a return of equity is appropriate if supported by the evidence and neither capricious nor arbitrary). It supports a cost of equity of 10.75%.

Order No. 2019-122, at p. 27.

- The ORS had itself abandoned witness Parcell's analysis in favor of its proposed "Plan B," that is, its acceptance of a 9.76% "average" authorized ROE based on decisions made by regulatory commissions over the past few years. ORS Brief at p. 32. In fact, parties to the case, Walmart, Inc. and South Carolina Energy Users Committee, supported the proposed ROE of 9.76%, and parties to the case, SC NAACP, SC Coastal Conservation League, Upstate Forever, Vote Solar and the South Carolina Solar Business Alliance, Inc., indicated they had no objection to the proposed ROE. *See March 25, 2019 ORS Letter Regarding the Return on Equity*.
- ORS witness Parcell testified that the Commission should set a lower ROE for DEC because of the effect of what he termed "favorable regulatory mechanisms" including several deferral requests that DEC has pursued in this proceeding. Tr., Vol. 6, pp. 1178-18 - 1178-24. However, in the Order, the Commission has rejected DEC's requests to use some of the very regulatory mechanisms that Parcell cited as a basis for his lower recommended ROE. There is no indication that the Order took into account that the Commission would refuse to allow DEC to use the very regulatory mechanisms that Parcell relied on for his opinion that a lower ROE was appropriate because DEC faced less risk.
- The Order incorrectly states that DEC witness Hevert acknowledged that DEC was "a less risky company today than in 2014 when the Commission granted a 10.2% ROE."

Order at p. 65. The actual testimony of Hevert was that the Company was not riskier than in 2014. Transcript, Vol. 8, p. 1843. Contrary to the Commission's conclusion, Hevert's actual testimony does not support a lower ROE than was granted in 2014.

- The Order mischaracterizes DEC witness Hevert's testimony in Docket Nos. 2017-207-E, 2017-305-E and 2017-370-E as supporting an ROE of 10.7% as compared to the 10.75% in the DEC proceeding. Order at p. 68. As is demonstrated in the quoted portions of Order Nos. 2018-804 and 2019-122 above, that is an incorrect statement. Hevert's recommended point estimate for SCE&G was 10.75%, the same as his recommendation for DEC.

The ruling in this proceeding that DEC must set rates using an ROE of 9.5% cannot be reconciled with the Commission's rulings in the SCE&G consolidated cases. It is also based on a misreading of the testimony of DEC witness Hevert's testimony and gives substantial weight to the clearly erroneous testimony of ORS witness Parcell. The ROE set by the Commission for DEC is therefore arbitrary, capricious and unlawful, and it prejudices substantial rights of the Company. The Commission should reconsider this issue.

D. Coal Ash Litigation Expenses (Adjustment #36).

Under well-established South Carolina law, "[a]lthough the burden of proof of the reasonableness of all costs incurred which enter into a rate increase request rests with the utility, the utility's expenses are presumed to be reasonable and incurred in good faith." *Hamm v. South Carolina Public Service Commission*, 309 S.C. 282, 266, 422 S.E.2d 110, 112 (1992). The record in this docket does not provide a basis for overcoming the presumption that the Company's coal ash litigation expenses were reasonable and incurred in good faith. DEC presented testimony and exhibits that showed that the coal ash litigation expenses it seeks to

recover in rates do not relate to any criminal matter or to any matter in which it has been determined that DEC violated environmental laws. Instead the testimony and exhibits, including late-filed Exhibit 56, showed that the coal ash litigation expenses relate to the normal and prudent operations of an enterprise like DEC.

A substantial portion of the litigation expenses relate to efforts by DEC to recover sums it has had to pay for coal ash related issues from more than twenty-five insurers that provided DEC with liability coverage during the time-period from 1971 to 1986. Any benefits derived from the insurance litigation will flow to the rate-payers who funded such litigation. It was prudent and reasonable for DEC to pursue coverage under these policies and it is appropriate that the expenses related to the litigation be included in rates. The Commission's decision not to allow recovery of these expenses is arbitrary and capricious. The Commission's decision to disallow these expenses should be reconsidered and reversed. Otherwise, if the litigation proves fruitful, then the proceeds of that litigation should be shared by those who paid for the litigation – customers in North Carolina, not customers in South Carolina.

CONCLUSION

The Commission should reconsider Order No. 2019-323 to address and remedy the unlawful rulings described in this petition. Pursuant to S.C. Code Ann. §58-27-2150, DEC requests that the Commission grant this petition, vacate order No. 2019-323 and issue a new order consistent with the arguments set out in this petition.

Dated this 31st day of May, 2019.

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STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2018-319-E

IN THE MATTER OF:	)	
	)	
Application Duke Energy Carolinas, LLC	)	SOUTH CAROLINA ENERGY
For Adjustments in Electric Rate Schedules	)	USERS COMMITTEE
and Charges	)	PETITION FOR REHEARING
	)	OR RECONSIDERATION

The South Carolina Energy Users Committee ("SCEUC"), Intervenor in the above referenced proceeding, hereby petitions the South Carolina Public Service Commission ("Commission") for rehearing or reconsideration of Order No. 2019-323, dated May 21, 2019, granting Duke Energy Carolinas, LLC ("Duke") an increase in its electric rate schedules and charges. SCEUC petitions the Commission pursuant to S.C. Code Ann. §58-27-2150 (1976) and S.C. Code Ann. Reg. 103-854 to reconsider certain of its findings and conclusions with respect to the Commission's decision to raise Duke's rates. For the reasons hereinafter set out, SCEUC would respectfully submit that the Commission committed the following errors of fact and law.

PRECONSTRUCTION COSTS

1) In its application filed November 8, 2018, Duke sought recovery of \$125 million in preconstruction costs with a return resulting from its abandoned Lee Nuclear Station project requesting a rate increase pursuant to S.C. Code Ann. Sections 58-27- 820 and 58-27-870. The preconstruction costs for which Duke now seeks recovery are not used and

useful to provide electricity. Duke elected to recover its nuclear plant preconstruction costs under S.C. Code Ann. Section 58-33-225 of the Base Load Review Act ("BLRA" or "Act"). The General Assembly has repealed the BLRA to prohibit Duke recovery of its preconstruction costs. Act 258, R287, H4375, Section 2.A

2) The nature of the proof required of Duke pursuant to S.C. Code Ann Section 58-33-225 and S.C. Code Ann. Sections 58-27-820 and 870 is inconsistent.¹ In enacting the BLRA, the General Assembly provided Duke with benefits not available under traditional forms of rate making such as provided in S.C. Code Ann. Sections 58-27-820 and 870. S.C. Code Ann. Sections 58-27-820 and 870 require Duke to invest hundreds of millions of dollars in nuclear construction before a prudency determination of its decision to construct the plants and subjects Duke to continuous litigation over the prudency issue. S.C. Code Ann. Section 58-33-225 provided Duke with the security of an upfront determination of prudency, sparing Duke the risk associated with the loss of hundreds of millions of dollars in nuclear investment.

3) In 2007, Duke elected to file its request under S.C. Code Ann. Section 58-33-225 for approval of its decision to incur preconstruction costs associated with its Lee Nuclear Station. *Carter v. Associated Petroleum Carriers*, 235 S.C. 80, 110 S.E.2d 8 (1959). By Order No. 2008-417 and Order No. 2011-454, the South Carolina Public Service Commission ("Commission") authorized Duke to incur the South Carolina allocable share of \$350 million in preconstruction costs through June 30, 2012. By June 30, 2012, Duke

¹ The inconsistency does not lie in the remedies Duke has invoked, but in the different statements of fact and remediable rights asserted in the respective dockets. *White v. Livingston*, 234 S.C. 74, 79, 106 S.E.2d 892(1959)

had spent \$251 million of the \$350 million authorized by the Commission. Duke continues to comply with the terms of Order Nos. 2008-417 and 2011-454.

4) The General Assembly repealed S.C. Code Ann. Section 58-33-225 effective June 28, 2018. In repealing S.C. Code Ann. Section 58-33-225, the General Assembly intended to protect ratepayers from payment of nuclear capital costs that are not used and useful. *Duquesne Light Co. V. Barasch*, 488 U.S. 299 (1989); see also SCAG Opinion September 26, 2017 at pages 43-46. Duke concedes that it was prohibited from seeking recovery of its preconstruction costs pursuant to S.C. Code Ann Section 58-33-225(G) of the BLRA. (Fallon prefiled direct testimony, p. 25. Ll. 6-15). The Commission has overlooked and misapprehended that having elected to accept the benefits of the BLRA, Duke is estopped from now filing for recovery of its nuclear preconstruction costs pursuant to S.C. Code Ann. Sections 58-27-820 and 870 which require proof of a different statement of facts and remediable rights. *White v. Livingston*, 234 S.C. 74, 106 S.E.2d 892(1959); *Lawson v. Rogers*, 312 S.C. 492, 435 S.E.2d 853 (1993).

5) A cardinal rule of statutory construction requires the Commission to ascertain the intent of the General Assembly in its application of a statute. *South Carolina Energy Users Committee v. South Carolina Public Service Commission*, 388 S.C 486, 697 S.E.2d 587 (2010). Moreover, the Commission's application of that statute may not lead to an absurd result. *Hamm v. South Carolina Public Service Commission*, 287 S.C. 180, 336 S.E.2d 470(1985) holding that no matter how clear the language of a statute may be, the court will reject that meaning when it leads to an absurd result not possibly intended by the legislature; *Carolina Power & Light Company v. Town of Pageland*, 321 S.C. 538, 471 S.E.2d 137 (1996) holding that a statute will be given retroactive effect if to hold otherwise

would lead to a result so plainly absurd that it could not possibly have been intended by the legislature or would defeat the plain legislative intent.

6) The Commission has overlooked and misapprehended that the intent of the General Assembly in enacting Act 258, R287, H4375, Section 2.A was to deprive Duke recovery of its nuclear preconstruction costs entirely. The impact of the Commission Order No 2019-323 is to circumvent the repeal of the BLRA by allowing Duke to recover all of its nuclear preconstruction costs. The Commission overlooked and misapprehended that its application of Act 258, R287, H4375, 2.A leads to an absurd result not intended by the General Assembly.

7) The Commission overlooked and misapprehended that it had limited Duke's recovery under the BLRA to \$60 million² and that by authorizing Duke recovery of \$125 million from its South Carolina ratepayers, the Commission's construction of Act 258, R287, H4375, Section 2.A rewards Duke for its delay in seeking recovery of its nuclear preconstruction costs and undermines the authority to which the Commission's orders are entitled. The Commission's application of Act 258, R287, H4375, Section 2.A leads to an plainly absurd result not intended by the legislature.

8) The Commission overlooked and misapprehended the legislative history of Act 258, R287, H4375, Section 2.A which prohibits Duke recovery of its nuclear preconstruction costs. After the disastrous abandonment of the nuclear construction at the VC Summer site in Jenkinsville, South Carolina, both the House and Senate convened special committees to study the impact of the failure of the South Carolina utilities to construct nuclear plants on ratepayers (the Speaker of the House convened the bipartisan

"House Utility Ratepayer Protection Committee" to develop remedies to protect ratepayers from unnecessary costs). The House and Senate, after much consideration, enacted a number of bills which were designed to protect ratepayers from having to pay for unnecessary nuclear construction costs. The Commission overlooked and misapprehended the fact that, by authorizing Duke recovery of \$125 million in nuclear preconstruction costs, twice that which was authorized under the BLRA, it has failed to protect ratepayers as was intended by Act 258, R287, H4375, Section 2.A.

9) The Commission overlooked and misapprehended the fact that reliance on thirty five year old precedent does not protect Duke's ratepayers. In relying upon Order No. 83-92 to authorize Duke recovery of \$125 million in nuclear preconstruction costs, the Commission overlooked thirty five years of intervening precedent such as the passage of the BLRA, the adverse impact of imposing billions of dollars of costs upon South Carolina ratepayers for unbuilt nuclear plants under the BLRA, and the General Assembly's repeal of the BLRA to protect Duke's ratepayers. Thirty five year old order does not serve as authority for ignoring the intent of the General Assembly in enacting Act 258, R287, H4375, Section 2.A. to protect ratepayers from the cost for nuclear construction that is not used and useful.

10) The Commission overlooked and misapprehended the fact that by authorizing Duke recovery of \$125 million in nuclear preconstruction costs, it rewarded the utility for its delay in seeking recovery of its costs. The Commission limited Duke to recovery of \$350

² The parties concede that Duke spent \$251 pursuant to its base load review orders. South Carolina's jurisdictional share is approximately \$60 million.

million systemwide in nuclear construction costs by Order No. 2011-554, expressly limiting Duke to recovery of AFUDC incurred through June 30, 2012. Duke incurred \$68 million in AFUDC by June 30, 2012. (Hearing Exhibit 19). By the time it filed for recovery of its nuclear preconstruction costs in 2018, Duke had booked \$248 million in AFUDC (Fallon prefiled direct testimony, p. 27). Consequently, Duke was rewarded with an additional \$180 million for its five year delay in seeking recovery of its nuclear preconstruction cost. The Commission overlooked and misapprehended the fact that the General Assembly never intended to reward Duke's delay in seeking recovery of its nuclear preconstruction costs under S.C. Code Ann Section 58-33-225(G), S.C. Code Ann. Sections 58-27-820 and 870 or Act 258, R287, H4375, Section 2.A. The Commission overlooked and misapprehended the fact that the rates authorized for recovery of AFUDC were not authorized by statute and are not just and reasonable.

11) The Petitioner requests that the Commission reconsider its order and to protect Duke's ratepayers, deny Duke recovery of \$125 million in nuclear preconstruction costs.

COAL ASH COST RECOVERY AT WH LEE

12) Duke's total cost to ratepayers for excavating its WH Lee coal ash pond is expected to be \$278.5 million, of which Duke sought to recover \$98.5 million from ratepayers in this docket. ("Wittliff direct p. 39, Table 5.4") The WH Lee coal ash pond was located contiguous to the electric generating plant.

13) Duke acted to justify its excavation of its coal ash pond on a consent agreement voluntarily entered into with the South Carolina Division of Health and Environmental

Control ("DHEC"). (Consent Agreement 14-13-HW). Not wishing to look a gift horse in the mouth as ORS witness Wittliff explained, DHEC entered into a consent agreement with Duke to excavate the WH Lee coal ash pond.

14) It is undisputed that the WH Lee coal ash pond was not subject to regulation by either the Environmental Protection Agency's Coal Combustion Residual rule ("CCR") or the North Carolina Coal Ash Management Act or CAMA.

15) Consent Agreement 14-13-HW reflects that Duke was in compliance with its permit of the existing coal ash pond. The Findings of Fact in the consent agreement reveal no violations of DHEC regulations. There is no record of seeps or spills. There is no record of surface water or ground water contamination. (Consent Agreement 14-13-HW at p. 2).

16) At the time of its consent agreement with DHEC, Duke had completed two engineering studies of its WH Lee coal ash pond, neither of which recommended excavation. Duke's engineering firm Soils and Materials Engineers (S&ME) recommended on September 12, 2014 that Duke merely monitor its WH Lee coal ash pond. Subsequently, on June 30, 2015, nine months after the consent agreement, Duke's engineers URS found no coal as pond dam safety issues requiring immediate attention. (O'Donnell prefiled direct at page 40, l. 22 – p. 41, l.19).

17) In finding that Duke was compelled to follow DHEC guidance requiring the coal ash from the WH Lee station to be disposed of in Class 3 landfills, the Commission overlooked and misapprehended the fact that the WH Lee coal ash pond was located contiguous to the WH Lee electric generating unit and exempted from the requirement to be excavated and hauled to a Class 3 landfill pursuant to 2016 H.B. 4857, codified as S.C.

Code Ann. Section 58-27-255(A)(1).³ Consequently, S.C. Code Ann. Section 58-27-255(A)(1) does not support the Commission's finding that DHEC had authority to mandate the coal ash excavation at WH Lee. To the contrary, 58-27-255(A)(1) compels the finding and conclusion that it was unnecessary to excavate the coal ash pond.

18) In addition, the Commission overlooked and misapprehended the fact that because the WH Lee coal ash pond met DHEC standards and was owned and operated by the utility that produced the electricity which resulted in the coal ash by product, DHEC had no authority to order Duke to remediate the coal ash pond. S.C. Code Ann. Section 58-27-255(A)(4).

19) The Commission overlooked and misapprehended the fact that to take advantage of Duke's offer to excavate the coal ash pond, DHEC was forced to act by agreement, negotiated at arm's length. Consent Agreement 14-13-HW was the result of a negotiated process whereby the regulator was forced to agree to covenant not to sue. (Consent Agreement 14-13-HW at p. 8). Had DHEC been acting pursuant to its statutory authority to close the coal ash pond, a covenant not to sue would have been unnecessary. See S.C. Code Ann. § 44-96-450. In addition, because DHEC was not acting under its regulatory authority, DHEC was forced to include language in the consent order granting it authority to inspect the remediation performed at the site. Had DHEC been acting pursuant to its regulatory authority, it would have been able to rely upon S.C. Code Ann. § 44-96-260 (4) for authority to enter upon the coal ash pond and inspect for compliance with State law.

³ H.B. 4857 relied upon by the Commission in its order was codified as S.C. Code Ann. Section 58-27-255. Duke witness Wright, a non-lawyer, mistakenly argued that H.B. 4857 passed in 2016 relied upon by the Commission at page 46 of provided the authority for DHEC to enter the consent agreement with Duke to excavate the WH Lee coal ash pond. Order No. 2019-323 at p. 46.

Instead, DHEC was forced to rely upon common law contractual concepts to accomplish the goal of closing the coal ash pond.

20) The Commission is charged with assessing the impact of a DHEC order on a utility's ratepayers and this Commission has exercised its authority to protect ratepayers from excessive measures imposed by DHEC. See Order No. 2004-203 in Docket No. 2003-218-S. Here, the Commission overlooked and misapprehended the fact that the existence of a DHEC consent agreement does not justify, much less compel, a decision by the Commission to require Duke's ratepayers to pay for the unnecessary excavation of the WH Lee coal ash pond.

21) The Commission overlooked and misapprehended the fact that the only reasonable inference from the record is that it was totally unnecessary to excavate the WH Lee coal ash pond, and that in closing the WH Lee coal ash pond, Duke acted imprudently. Forcing Duke's ratepayers to pay \$278.5 for this unnecessary expense is incomprehensible to ratepayers.

22) The Petitioner requests that the Commission reconsider its order and deny Duke recovery of the cost of excavating the WH Lee coal ash basin.⁴

REAL TIME PRICING

23) The Commission overlooked and misapprehended the fact that because Duke prices its real time pricing ("RTP") rates at its own marginal costs, manufacturers are paying higher costs than necessary. There are times when Duke's marginal cost of power offered to its manufacturing customers is greater than the price Duke could pay for that same

⁴ SCEUC concurs with the Commission order which protects South Carolina ratepayers by disallowing \$469,894,472 in CAMA-only costs.

power in the open wholesale market. In addition, when Duke fails to take advantage of lower cost power on the wholesale market, it is also needlessly running its higher cost generating plants adding to higher fuel costs paid by all consumers. (O'Donnell prefiled direct at p. 50, l. 29 – p.51, l. 13).

24) The Commission overlooked and misapprehended the significant impact Duke's RTP rates have on Duke's manufacturing customers. A manufacturer with a 20 MW load in Duke's territory would have paid an additional \$2.5 million for electricity, excluding transmission costs, than had the manufacturer purchased that same power from the Dominion Hub. (O'Donnell prefiled direct p. 53, ll. 1-8)

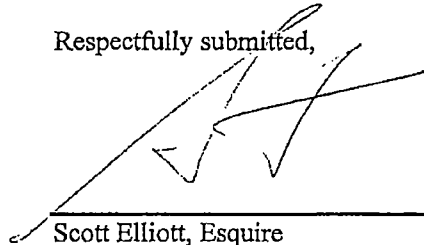
25) The Commission overlooked and misapprehended the fact that RTP costs designed to create a competitive manufacturing marketplace in South Carolina as proposed by SCEUC witness O'Donnell are just and reasonable.

26) The petitioner requests that the Commission reconsider its order and require Duke to provide real time pricing rates at the lowest cost practicable without prejudicing Duke ratepayers and shareholders by fixing RTP rates which are competitive in the market and reduce the costs to manufacturers

CONCLUSION

For the foregoing reasons, as well as those set out at trial and in its brief to the Commission submitted April 25, 2019, the South Carolina Energy Users Committee respectfully requests that the Commission rehear those issues set out above, reconsider its Order No. 2019-323 respecting those issues and issue its order consistent with the arguments set out above.

Respectfully submitted,



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Energy Users Committee*

Columbia, South Carolina
May 31, 2019

1 printing process. It's probably a third-party
2 printing, which is even more expensive. And it
3 needs to stop.

4 [Applause]

5 I think this increase could be saved by stuff
6 like this, if you look into your departments to see
7 how your money's being spent. Also, the
8 telemarketers that call me, they have to be paid.
9 I don't think it's -- I think some of it's redundant
10 because I get it on my cell phone, that I'm paying
11 for, and you're also having somebody pick up the
12 phone and call me once every two weeks, wanting me
13 to do a savings program. I have also an 89-year-
14 old dad that lives with me, and I can't afford to
15 leave him without air or power. And I wouldn't do
16 it for \$8 a month anyway.

17 I want to be just as comfortable as anybody
18 else, but I do not think this increase is
19 necessary. Thank you.

20 [Applause]

21 CHAIRMAN RANDALL: Thank you.

22 Parties?

23 [No response]

24 Commissioners?

25 <

1 address is 108 Kirkwood Drive, in Moore, 29369.

2 As we know, we're here today because Duke
3 Energy is looking for, I think, \$168 million for
4 things that they call modernizations or
5 improvements. Now, coming from an industrial
6 background, words like "modernizations" and
7 "improvements" were words that we used when we
8 realized that we didn't do the maintenance that we
9 were supposed to do and had budgeted for already,
10 and needed to replace some things that had worn out
11 in kind of an emergency situation.

12 So what we've seen over the past decade is
13 pretty phenomenal, in actuality. We've seen people
14 across all income ranges, and everything else,
15 replace a lot of lighting, a lot of appliances, a
16 lot of things like that in their homes, for more
17 energy-efficient models; we've seen for the first
18 time ever, people are generating electricity at
19 their home and contributing to the grid themselves,
20 which Duke's happy to buy and sell at a profit.
21 That gives some equipment that Duke Energy doesn't
22 even have to pay for and doesn't even have to
23 maintain themselves; the people are happy to
24 maintain out of their pockets. So it's troublesome
25 to me to see that they want \$168 million for lack

NIGHT HEARING/SPARTANBURG - VOLUME 1

3/12/19

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DIRECT EXAMINATION

BY MS. H. SMITH:

Q Mr. Gharthey-Tagoe, could you please state your full name and business address.

A [GHARTEY-TAGOE] My full name is Kodwo Gharthey-Tagoe. Business address: 40 West Broad Street, Greenville, South Carolina 29601.

Q Thank you. By whom are you employed and in what capacity?

A [GHARTEY-TAGOE] I'm employed by Duke Energy Corporation as State President of South Carolina.

Q And did you cause to be prefiled in this docket direct testimony consisting of 40 pages?

A [GHARTEY-TAGOE] I did.

Q And do you have any changes or corrections to your direct testimony?

A [GHARTEY-TAGOE] No, ma'am.

Q If I asked you the same questions today, would your answers be the same?

A [GHARTEY-TAGOE] They would.

Q Okay. Now, Mr. Gharthey-Tagoe, did you cause to be prefiled in this docket rebuttal testimony consisting of 19 pages?

A [GHARTEY-TAGOE] I did.

Q Do you have any changes or corrections to that rebuttal

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1 testimony.

2 A [GHARTEY-TAGOE] No, ma'am.

3 Q And if I asked you the same questions today, would your
4 answers be the same?

5 A [GHARTEY-TAGOE] They would.

6 MS. SMITH: Mr. Chairman, at this time, I move
7 that the prefiled direct testimony and the rebuttal
8 testimony of Mr. Gharthey-Tagoe be copied into the
9 record as if given orally from the stand.

10 CHAIRMAN RANDALL: Mr. Gharthey-Tagoe's
11 prefiled direct testimony and – what was the other?
12 Rebuttal?

13 MS. SMITH: Yes, sir.

14 CHAIRMAN RANDALL: – rebuttal testimony will
15 be entered into the record as though given orally
16 from the stand.

17 MS. H. SMITH: All right. Thank you.

18 BY MS. H. SMITH:

19 Q Ms. Smith, please state your full name and business
20 address.

21 A [K. SMITH] Kim Hamrick Smith, 550 South Tryon Street,
22 Charlotte, North Carolina.

23 Q And by whom are you employed and in what capacity?

24 A [K. SMITH] Duke Energy Carolinas as a Director of Rates
25 and Regulatory.

1 Q And did you cause to be prefiled in this docket direct
2 testimony consisting of 43 pages and Smith Exhibits 1
3 through 3 consisting of 33 pages?

4 A [K. SMITH] Yes, I did.

5 Q Do you have any changes to that testimony or exhibits?

6 A [K. SMITH] No, I do not.

7 Q Did you also cause to be prefiled in this docket
8 supplemental direct testimony consisting of 10 pages and
9 Supplemental Exhibit 1 consisting of one page, and
10 Updated Smith Exhibit 2 consisting of three pages?

11 A [K. SMITH] Yes, I did.

12 Q Okay. And do you have any changes or corrections to
13 that testimony?

14 A [K. SMITH] No, I do not.

15 Q And if I asked you the same questions today, would your
16 answers be the same?

17 A [K. SMITH] Yes, ma'am, they would.

18 Q Okay. Rounding out here, did you also cause to be
19 prefiled in this docket rebuttal testimony consisting of
20 25 pages and Smith Rebuttal Exhibits 1 through 3
21 consisting of 33 pages?

22 A [K. SMITH] Yes.

23 Q And do you have any changes or corrections to that
24 rebuttal testimony?

25 A [K. SMITH] No, I do not.

1 Q And if I asked you the questions today, would your
2 answers be the same?

3 A [K. SMITH] Yes, they would.

4 MS. SMITH: Okay. Mr. Chairman, At this time,
5 I move that the prefiled direct testimony,
6 supplemental direct, and rebuttal testimony of Ms.
7 Smith, as well as her exhibits, be copied into the
8 record as if given orally from the stand.

9 CHAIRMAN RANDALL: Okay. Ms. Kim Smith's
10 prefiled direct testimony, supplemental direct
11 testimony, and rebuttal testimony will be entered
12 into the record as though given orally from the
13 stand.

14 Her exhibits will be entered as Hearing
15 Exhibit No. 10.

16 [WHEREUPON, Hearing Exhibit No. 10 was
17 marked and received in evidence.]

18 MS. H. SMITH: Thank you. And we have passed
19 out to the Commission copies of summaries for Mr.
20 Gharthey-Tagoe and Ms. Smith.

21 BY MS. H. SMITH:

22 Q And you both have summaries you'd like to deliver for
23 the Commission; is that correct?

24 A [K. SMITH] Yes.

25 A [GHARTEY-TAGOE] That's correct.

1 MS. H. SMITH: And at this time, we do have
2 extra copies of that summary. I would ask Ms.
3 Moniqua to pass those out to anybody who would like
4 to see them.

5 BY MS. H. SMITH:

6 Q So just one after the other, just for the efficiency of
7 time, Mr. Gharthey-Tagoe, would you like to deliver your
8 summary of your testimony, followed by Ms. Smith?

9 CHAIRMAN RANDALL: We want to make sure y'all
10 get close to the mic, so – you're not – you've got
11 to speak into it so everybody can hear and we can
12 pick it up on live-streaming. Thank you.

13 WITNESS GHARTEY-TAGOE: Good morning, Mr.
14 Chairman, and Commissioners.

15 We are here today seeking a change in rates to
16 reflect our continued investments in the State of
17 South Carolina and the costs to provide safe,
18 reliable, cost-effective, and increasingly clean
19 electricity to our customers.

20 As I describe in my direct testimony, Duke
21 Energy Carolinas has invested heavily in cleaner-
22 burning natural gas fuel plants, including the W.S.
23 Lee combined-cycle natural gas plant in Anderson
24 County. Natural gas fuel plants, like the Lee CC,
25 emit carbon dioxide at about half the rate, and

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1 nitrogen and sulfur oxide emissions at a fraction
2 of the rate of the coal plants they replace. The
3 company has also invested an additional \$152
4 million in the development of two large solar
5 facilities, providing additional carbon-free
6 renewable generation to our customers. Duke Energy
7 Carolinas is also requesting recovery of project
8 development costs related to the Lee nuclear
9 project.

10 The company has also started the process to
11 ensure compliance with state and federal
12 regulations requiring the company to address coal-
13 ash basin closures at plants which have served or
14 are continuing to serve the customers in South
15 Carolina. We have worked hard to reduce our impact
16 on the environment by retiring older, less
17 efficient coal plants across the Carolinas, and
18 have retired all of our coal plants in South
19 Carolina. Duke Energy recycled more than 78
20 percent of coal-combustion byproducts in 2017, and
21 that includes Duke Energy Carolinas recycling or
22 beneficially reusing the ash that is produced at
23 our coal-fired plants.

24 We have retired half of the coal-fired plants
25 owned by Duke Energy in the Carolinas. And now

1 we're closing all ash basins across the Carolinas
2 in compliance with new sweeping state and federal
3 laws and regulations, as part of Duke Energy's
4 commitment to provide increasingly reliable,
5 cleaner power to customers at reasonable rates.
6 Like any waste, we must ensure that coal ash is
7 managed responsibly.

8 Additionally, we are planning for the future
9 by starting the process of rolling out a new
10 customer information system to ensure the best
11 customer service possible, by completing the
12 deployment of AMI smart meters within the Duke
13 Energy Carolinas territory and, based on customer
14 feedback, offering fee-free payment programs for
15 residential customers for all methods of payment.

16 As a result of these investments and other
17 costs, the company is requesting amortization of
18 regulatory assets related to environmental
19 compliance costs, the Lee CC plant, the Carolinas
20 West Primary Control Distribution Center, advanced
21 metering infrastructure, and the customer
22 information system. We believe it is necessary to
23 make these investments to better serve our
24 customers. We know that these smart investments in
25 technology, infrastructure, and environmental

1 protection will help connect millions of our
2 customers to the energy future they expect.

3 In my rebuttal testimony I address major
4 concerns that were raised at the time by the Office
5 of Regulatory Staff and other Intervenors. The
6 first issue that I address is the ORS's suggestion
7 that South Carolina customers should not have to
8 pay for costs which the company incurred to comply
9 with North Carolina's Coal Ash Management Act, also
10 known as CAMA.

11 Historically, the company's generation, fuel,
12 and associated costs are allocated between South
13 Carolina and North Carolina. The ORS incorrectly
14 suggests that CAMA imposes additional expenses on
15 South Carolina. To the contrary, the coal ash
16 beneficiation requirements in CAMA will result in
17 South Carolina customers receiving millions of
18 dollars in net savings.

19 The second issue concerns some fundamental
20 disagreements on the company's proposed return on
21 equity and deferred costs. The ORS proposes to
22 stretch certain deferred costs over an extended
23 period without recognizing the cost to finance the
24 balances during that period. Their proposal
25 ignores the way the company finances its carrying

1 costs; departs from good regulatory practice, and
2 arbitrarily attempts to lower the company's cost of
3 capital. We have shown that the company's proposed
4 return on equity is in line with other ROEs
5 determined by other regulatory commissions in the
6 Southeast.

7 Finally, I address the reactions to the
8 company's proposal for the cost-based facilities
9 charge which is allocated to each customer. We do
10 not contest the basic facilities charge proposed in
11 ORS Witness Seaman-Huynh's surrebuttal testimony of
12 an \$11.96 basic facilities charge for Residential
13 Non-Time-of-Use customers, \$13.09 for Residential
14 Time-of-Use customers, and \$11.70 for Small General
15 Service customers, and to put the remaining revenue
16 requirement ultimately determined by the Commission
17 in the variable components of such rates.

18 In ongoing conversations with customers, in
19 listening to testimony at public hearings, and
20 after reading relevant testimony and comments filed
21 by Intervenor and customers, we continue to hear
22 the concerns of our customers. The company
23 realizes that, regardless of how justified a rate
24 case may be, there is no good time to raise
25 customer rates.

1 The company wants to help customers understand
2 their energy use, empower them to save money on
3 their electric bill, and provide programs for every
4 type of energy user and budget.

5 This concludes the summary of my direct and
6 rebuttal testimony.

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23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED DIRECT TESTIMONY OF KWODO
25 GHARTEY-TAGOE FOLLOWS HEREINAFTER]

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2018-319-E

In the Matter of:	)	
	)	DIRECT TESTIMONY OF
Application of Duke Energy Carolinas, LLC	)	KODWO GHARTEY-TAGOE
for Adjustments in Electric Rate Schedules	)	FOR DUKE ENERGY
and Tariffs	)	CAROLINAS, LLC

I. INTRODUCTION

1 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION**
2 **WITH DUKE ENERGY CORPORATION.**

3 **A.** My name is Kodwo Ghartey-Tagoe, and my business address is 40 West
4 Broad Street, Greenville, South Carolina 29601. I am State President – South
5 Carolina for Duke Energy Carolinas, LLC (“DE Carolinas” or “Company”)
6 and Duke Energy Progress, LLC (“DE Progress”), both of which are wholly
7 owned subsidiaries of Duke Energy Corporation (“Duke Energy”).

8 **Q. BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND**
9 **AND PROFESSIONAL AFFILIATIONS.**

10 **A.** I earned my Juris Doctor degree from Duke University and a Bachelor of Arts
11 degree, with joint honors in economics and finance, from McGill University
12 in Montreal, Quebec. I also completed the Advanced Management Program at
13 the Wharton School of Business. I am admitted to the North Carolina Bar.
14 I serve on the Board of Directors of the United Way of Greenville County and
15 the Palmetto Conservation Foundation, and on the board of visitors of Duke
16 University Law School. I am also on the advisory board of Progress in
17 Education, Inc., a charitable and educational organization I helped found in
18 2000 to assist schools in Ghana to improve their quality of instruction, and to
19 promote cross-cultural understanding between students in Ghana and students
20 in America.

1 **Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND**
2 **EXPERIENCE.**

3 A. I have been in my current position since January 2017. Prior to that, I served
4 as senior vice president of state and federal regulatory legal support for Duke
5 Energy. I joined the Company in 2002 as chief regulatory counsel for Duke
6 Power. I have served as vice president, legal, for Duke Energy's Commercial
7 Businesses organization, and was responsible for providing legal advice to the
8 Company's commercial businesses, including Duke Energy International,
9 Duke Energy Renewables, Midwest Commercial Generation and Commercial
10 Transmission. I also served as Duke Energy's general counsel for litigation,
11 as well as vice president, legal – state regulation for Duke Energy's
12 Franchised Electric and Gas business. Before joining the Company, I was a
13 partner with McGuire Woods LLP in Richmond, Virginia.

14 **Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT**
15 **POSITION?**

16 A. I lead Duke Energy's regulated electric utility businesses in South Carolina,
17 which include serving approximately 591,000 DE Carolinas electric
18 customers in South Carolina. I am responsible for the financial performance
19 of the Company's electric utility in South Carolina and managing state and
20 local regulatory and governmental relations, and community affairs. I also
21 have responsibility for advancing the Company's legislative and regulatory
22 initiatives related to its electric operations.

1 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE
2 COMMISSION?

3 A. Yes. On July 23, 2018, I testified before the Commission on behalf of DE
4 Progress and DE Carolinas in an allowable ex parte proceeding in Docket No.
5 ND-2018-19-E on the management of Duke Energy hydroelectric projects.

6 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

7 A. The purpose of my testimony is to provide an overview of DE Carolinas'
8 requested rate increase in support of the Company's Application in this case.
9 In my testimony, I explain the primary cost drivers making up this requested
10 rate increase, as well as the steps we have taken to minimize DE Carolinas'
11 cost to provide safe, reliable, cost-effective and increasingly clean electricity
12 to our customers, including work related to environmental compliance
13 requirements. I explain how we are improving our grid in a manner to better
14 our customers' lives and the economy of our State. Finally, I describe how the
15 requested rate increase will allow the Company to remain a financially strong
16 utility that is well positioned in financial markets to the benefit of our
17 customers.

18 Q. WHO ARE THE OTHER WITNESSES PRESENTING TESTIMONY IN
19 SUPPORT OF THE COMPANY'S APPLICATION IN THIS
20 PROCEEDING?

21 A. The Company's other witnesses filing direct testimony in support of this case
22 are:

- 1 1. **Kim H. Smith**, Director of Rates & Regulatory, who describes the
2 results of DE Carolinas' operations under present rates on the basis of
3 an adjusted historical Test Period (twelve months ending December
4 31, 2017). Witness Smith details the calculation of the additional
5 revenue required as a result of the investments and general cost
6 increases since the last DE Carolinas Rate Case and discusses several
7 pro forma adjustments to the test year operating expenses and to the
8 end of year actual rate base. Witness Smith also explains the
9 calculations for various accounting requests the Company makes in its
10 Application. Further, Witness Smith provides the capital structure and
11 embedded cost of debt used by the Company in calculating its
12 proposed increase. Finally, Witness Smith explains the proposal the
13 Company is making regarding an excess deferred income taxes
14 ("EDIT") rider and cost recovery related to grid investments.
- 15 2. **Steven Capps**, Senior Vice President of Nuclear Operations for Duke
16 Energy, who provides an update on capital additions in recent years, as
17 well as key drivers impacting nuclear operations and maintenance
18 ("O&M") costs. Witness Capps also discusses the operational
19 performance of DE Carolinas' nuclear generation fleet during the
20 January 1, 2017 through December 31, 2017 Test Period.
- 21 3. **John Sullivan**, Director of Corporate Finance and Assistant Treasurer,
22 who addresses the Company's financial objectives, proposed capital
23 structure and cost of capital. Witness Sullivan also discusses the

1 current credit ratings and forecasted capital needs of the Company and
2 the importance of DE Carolinas' continued ability to meet its financial
3 objectives.

4 4. **David L. Doss Jr.**, Director of Electric Utilities and Infrastructure
5 Accounting, who describes the financial position of DE Carolinas at
6 December 31, 2017, and the actual results of the Company's
7 operations for the Test Period. He also addresses depreciation expense
8 and nuclear decommissioning costs. Finally, he details nuclear
9 decommissioning costs allocated to the Company's South Carolina
10 retail customers and that the Company is not including any
11 decommissioning costs in its rate request.

12 5. **Janice Hager**, President of Janice Hager Consulting. Witness Hager
13 supports the allocation of DE Carolinas' electric operating revenues
14 and expenses, and original cost rate base assigned to the South
15 Carolina retail jurisdiction and to each customer class.

16 6. **Robert B. Hevert**, Partner of ScottMadden, Inc., who presents his
17 independent analysis of the Company's cost of equity. Witness Hevert
18 discusses the Company's requested capital structure and makes a
19 recommendation for an allowed return on equity ("ROE") to allow the
20 Company to both attract capital on reasonable terms and maintain
21 financial strength.

- 1 7. **John Panizza**, Director of Tax Operations, who addresses the recently
2 enacted federal tax reform legislation, the Tax Cuts and Jobs Act (the
3 “Tax Act”), which became law on December 22, 2017.
- 4 8. **Retha Hunsicker**, Vice President Customer Connect-Solutions for
5 Duke Energy. Witness Hunsicker discusses the Company’s Customer
6 Information Systems (“CIS”) and explains why it is necessary to
7 convert that CIS into a modern customer service platform, known as
8 Customer Connect.
- 9 9. **Jon F. Kerin**, Vice President, Coal Combustion Products Operations,
10 Maintenance and Governance, who describes DE Carolinas’ ash basin
11 closure and compliance costs and plans, and the activities underlying
12 the costs sought for recovery in this case.
- 13 10. **Dr. Julius (Chip) Wright, Ph.D.**, Managing Partner, J. A. Wright &
14 Associates, LLC, will testify to ratemaking policy and regulatory
15 approaches to the recovery of prudently incurred environmental
16 compliance costs.
- 17 11. **Kimberly D. McGee**, Rates & Regulatory Strategy Manager with
18 Duke Energy, who supports the base fuel factor for base rates for all
19 customer classes for DE Carolinas.
- 20 12. **Joseph A. Miller Jr.**, Vice President of Central Services, who provides
21 an update on the Company’s fossil, hydroelectric and solar
22 (collectively, “Fossil/Hydro/Solar”) facilities included for recovery in
23 this case. Witness Miller describes capital additions made in recent

1 years and capital investments planned for the upcoming years and key
2 drivers impacting O&M costs. Witness Miller also discusses the
3 operational performance of the Company's Fossil/Hydro/Solar fleet
4 during the Test Period.

5 13. **Christopher M. Fallon**, former Vice President of Nuclear
6 Development for Duke Energy. Witness Fallon provides background
7 on the nuclear development activities related to the proposed Lee
8 Nuclear Station Units 1 and 2 (referred to as the "Lee Nuclear
9 Project") submitted in this case for cost recovery, and explains the
10 Company's decision to cancel the Lee Nuclear Project as originally
11 envisioned.

12 14. **Nils J. Diaz, Ph.D.**, a consultant at ND2 Group, LLC, who addresses
13 the reasonableness and prudence of the strategy and efforts of the
14 Company to obtain a combined operating license ("COL") for the Lee
15 Nuclear Project.

16 15. **Jay W. Oliver**, General Manager, Grid Solutions Engineering and
17 Technology, who discusses the Company's transmission and
18 distribution ("T&D") system, the operation and performance of the
19 T&D system and the costs necessary to operate, maintain and improve
20 upon it, including providing detail on major grid investment initiatives,
21 and the underlying investments to be recovered through the
22 Company's Grid Improvement Plan.

1 16. **Michael J. Pirro**, Director of Southeast Pricing & Regulatory
2 Solutions, who will demonstrate that the rates DE Carolinas proposes
3 reflect appropriate ratemaking principles, and result in an equitable
4 basis for recovery of the Company's revenue requirement across and
5 within its various rate schedules. Witness Pirro also describes proposed
6 changes to the Company's retail electric schedules and quantifies the
7 effect of these changes to retail customers.

8 17. **James H. Cowling**, Outdoor Lighting Director, who explains DE
9 Carolinas' outdoor lighting business and expands upon Witness Pirro's
10 testimony regarding the rate design for the Company's outdoor
11 lighting products and services.

12 18. **Donald L. Schneider Jr.**, General Manager, Advanced Metering
13 Infrastructure ("AMI") Program Management, who describes the
14 Company's progress in deploying AMI technology across its South
15 Carolina service territory.

16 **II. SUMMARY OF REQUEST**

17 **Q. WHY IS DE CAROLINAS PROPOSING A BASE RATE**
18 **ADJUSTMENT?**

19 **A.** Recent work to maintain and modernize our electric system, efforts to
20 generate cleaner power (including exploring nuclear development),
21 responsibly manage and close coal ash basins, improve reliability, and
22 continually enhance service to customers have made it necessary for DE
23 Carolinas to request a net base rate increase in its retail revenues of

1 approximately \$168 million on June 1, 2019, which represents an approximate
2 overall 10 percent increase in our annual revenues. The Company is also
3 presenting a three-year plan known as the South Carolina Grid Improvement
4 Plan, which I believe will effectively serve customers now and in the years
5 ahead. The Company's Application requests that the Commission approve the
6 Grid Improvement Plan and expenditures for the next three years as detailed
7 in Exhibit 9 to Witness Oliver's testimony. If approved, additional rate
8 changes related to the Grid Improvement Plan would result in cost recovery of
9 approximately \$16 million on June 1, 2020 and \$20 million June 1, 2021.

10 This increase is necessary to pay for investments to build a cleaner, more
11 reliable and smarter energy future in South Carolina. Our investments include
12 the complete deployment of new meters that align with a new customer
13 information system to give customers more information and service options; full
14 commercialization of our Prepaid Advantage program to allow all eligible DE
15 Carolinas residential customers the opportunity to avail themselves of a
16 prepayment plan that can eliminate the need for deposits. Additional customer
17 focused changes include eliminating the need for our residential customers to
18 pay a fee every time they use a credit or a debit card to make a payment, by
19 including the amount of the fees in our cost of service and collecting them in
20 rates.

21 Further, this case includes grid investments being made by the Company
22 to improve and modernize our operations for the benefit of customers. The
23 unique nature of these investments is why DE Carolinas is proposing the Grid

1 Improvement Plan, and is why we are seeking corresponding rate changes to
2 recover the cost of the three-year plan, as discussed by Witnesses Smith, Oliver
3 and Pirro.

4 These smart investments in technology, infrastructure, environmental
5 protection and customer service will help connect customers to a cleaner, more
6 reliable, smarter energy future. At Duke Energy, we know how vital electricity
7 is to our customers and their families, as well as our state. Customers expect the
8 Company to deliver electricity that is safe, reliable, affordable and increasingly
9 clean, while also making smart investments that help communities and local
10 economies thrive, create jobs and opportunities, and that provide more value
11 every day.

12 We are providing customers with increasingly clean energy from state-
13 of-the-art carbon-free nuclear plants and new, highly-efficient natural gas and
14 utility-scale solar energy projects. In fact, nearly half of the electricity we
15 generated in the Carolinas last year came from carbon-free resources,
16 including hydro-electric facilities. Powering the lives of South Carolina's
17 hard-working families and communities is the most important job we have.
18 Our more than 4,000 dedicated Duke Energy employees who live and work
19 every day in communities across our state— in good weather and bad – and the
20 thousands more out of state employees who support our service in South
21 Carolina, take this responsibility seriously. Smart investments in technology,
22 infrastructure and environmental protection will help connect millions of our
23 customers to a better energy future.

1 Q. IF APPROVED, WHAT WOULD BE THE IMPACT OF THE
2 COMPANY'S REQUESTED INCREASE TO THE TYPICAL
3 RESIDENTIAL CUSTOMER CONSUMING 1000 KWHS PER
4 MONTH?

5 A. The requested revenue increase of \$168 million on June 1, 2019, followed by
6 incremental increases to reflect additional grid investments in 2020 and 2021
7 would result in the following increases by DE Carolinas' rate classes: (1) a
8 typical residential customer using 1,000 kWh will see an increase of
9 approximately \$15.57 per month beginning with the rate effective date in this
10 case, requested to be June 1, 2019, and then an increase of \$1.54 per month
11 beginning June 1, 2020 and an additional \$1.92 per month beginning June 1,
12 2021; commercial customers, on average, will see a 7.7 percent increase on
13 June 1, 2019, and then an increase of 0.6 percent per month beginning June 1,
14 2020 and an additional 0.8 percent increase per month beginning June 1,
15 2021; industrial customers, on average, will see a 8.8 percent increase on June
16 1, 2019, and then an increase of 0.4 percent increase per month beginning
17 June 1, 2020 and an additional 0.5 percent increase per month beginning June
18 1, 2021; lighting customers, on average, will see a 15.2 percent increase on
19 June 1, 2019, and then an increase of 2.1 percent increase per month
20 beginning June 1, 2020 and an additional 2.1 percent increase per month
21 beginning June 1, 2021. More details can be found in the testimony of
22 Witness Pirro.

1 DE Carolinas is also proposing, supported by costs to serve, an
2 increase in the Residential Basic Facilities Charge from \$8.29 to \$28.00 per
3 month effective June 1, 2019. This means that customers would be paying
4 approximately \$0.93 cents per day for facilities in place to serve them,
5 regardless of how much electricity is used. The increase in the Residential
6 Customer Charge is not additive to the rate increase requested in this case.
7 Rather, the proposed change is a more accurate reflection of how the
8 Company collects its costs. The Company proposes to collect fixed cost
9 through the fixed monthly charge based on the cost to serve instead of
10 continuing to collect it through the variable, volumetric energy rate. We took
11 this approach because current rates significantly understate the current cost of
12 service related to the customer component of cost. Further, our requested fixed
13 monthly charge is comparable to the fixed monthly charge established by
14 many other electricity providers in the State. Witnesses Pirro and Hager
15 explain this in further detail in their testimony.

16 **III. BASE RATE REQUEST**

17 **Q. PLEASE PROVIDE MORE DETAIL ABOUT THE INVESTMENTS**
18 **DRIVING THE COMPANY'S REQUESTED 10.0 PERCENT**
19 **OVERALL ADJUSTMENT TO ANNUAL REVENUES.**

20 **A.** Since DE Carolinas' last rate case in 2013 ("2013 Rate Case"), we have
21 continued to invest in our facilities, equipment and operations to better serve
22 our customers. For example, since the conclusion of the 2013 Rate Case, DE
23 Carolinas has completed numerous nuclear, fossil, hydro and solar projects,

1 helping to provide customers with energy that is more reliable, efficient and
2 cleaner than ever. DE Carolinas has invested approximately \$639 million in
3 new gas-fueled generation, replacing older, less-efficient coal-fired generation
4 with state-of-the-art, cleaner burning natural gas-fueled plants. A significant
5 example is the W.S. Lee Combined Cycle ("Lee CC") plant, completed in
6 April 2018. The Lee CC features state-of-art technology for increased
7 efficiency and significantly reduced emissions. Natural gas plants, including
8 the Lee CC facility, emit carbon dioxide at about half the rate, and nitrogen
9 and sulfur oxide emissions at a fraction of the rate of the units they replaced.

10 Further, to advance towards a more sustainable energy future, DE
11 Carolinas constructed two large solar projects (Mocksville and Monroe) in
12 2016 and 2017. These projects add a total of 75 MWs of nameplate capacity,
13 providing 35 MWs of relative dependable summer capacity to DE Carolinas'
14 generation fleet. The Company's investment in these projects totaled \$152
15 million. The Company also completed the relicensing effort for the 13
16 hydroelectric facilities on the Catawba-Wateree river basins, totaling \$126
17 million in capital investment. The 40-year license (FERC #2232) was granted
18 in November 2015 and allows our stations to operate until 2055. The new
19 license replaces the old license that expired in 2006. These investments will
20 provide benefits to DE Carolinas' customers for decades to come, as discussed
21 by Witness Miller.

22 The Company's Application also requests the recovery of costs for
23 nuclear project development work completed for the Lee Nuclear Project, as

1 discussed by Witness Fallon. Witness Smith discusses the Company's
2 proposal to recover these costs in the amount of \$20 million per year for 12
3 years. The Company seeks to retain the combined operating license, or COL,
4 granted by the NRC in December, 2016, in case circumstances change.
5 Witness Diaz explains in his testimony why the Company's proposal to retain
6 the COL is appropriate.

7 In addition, since the conclusion of the 2013 Rate Case, DE Carolinas
8 has worked to improve reliability and customer service. To bring customers
9 additional choices and insight on their usage, the Company has implemented
10 AMI across the DE Carolinas' system and has replaced conventional meters
11 with smart meters. As fully described in Witness Schneider's testimony, as of
12 September 2018, DE Carolinas has completed its deployment of AMI,
13 installing approximately 590,000 smart meters in its South Carolina service
14 territory. The data enabled by AMI, when combined with the new Customer
15 Connect System, will lead to expanded options and flexibility in supporting
16 enhanced customer services and programs. Accordingly, we are seeking
17 recovery of costs related to the implementation of Customer Connect and
18 related to the deployment of the Company's new smart meters as discussed in
19 detail in Witness Smith's testimony. See Witnesses Hunsicker and Schneider
20 for additional information regarding the costs associated with Customer
21 Connect and Smart Meters.

22 DE Carolinas also seeks to recover costs incurred and deferred since
23 January 1, 2015, through December 31, 2018 to comply with federal and state

1 requirements related to CCRs. To mitigate rate impacts to customers, we
2 request to recover these previously incurred expenses over a five year period
3 in the amount of approximately \$62 million per year.¹ This case also includes
4 the amortization of regulatory assets over time related to Lee CC;² smart
5 meters;³ the new Customer Connect system;⁴ grid investments;⁵ the Carolina
6 West Primary Control Distribution Center;⁶ and rate changes from the most
7 recent depreciation study. Witness Smith provides detail regarding these
8 deferral balances and the requested amortization.

9 **Q. HAS THE IMPACT OF THE TAX ACT BEEN INCORPORATED INTO**
10 **THE COMPANY'S REQUEST?**

11 A. Yes. The proposed rates include a reduction from the corporate income tax
12 rate from 35 percent to 21 percent. The Company also includes a proposal to
13 flow back to customers, through a rider, excess deferred income taxes
14 ("EDIT") and deferred revenue resulting from the Tax Act on utility
15 operations. The Company's plan ensures that as customer benefit from the
16 Tax Act, the Company is able to maintain the same financial strength it had
17 prior to the Tax Act's passage. Finally, the Tax Act balances applied in this
18 case include an offset to the balance accrued for Distributed Energy Program
19 ("DERP") costs that have yet to be recovered. The balances have grown to
20 \$40 million as of September 30, 2018, as provided by Witness Smith. Given

¹ This case excludes any fines or penalties incurred by DE Carolinas related to ash basin closure or management.

² Docket No. 2018-207-E, Order No. 2018-552 (2018).

³ Docket No. 2016-240-E, Order No. 2018-552 (2018).

⁴ See *supra* n. 2.

⁵ Docket No. 2018-206-E, Order No. 2018-519 (2018).

⁶ See *supra* n. 2.

1 the benefits from the Tax Act, we thought it was reasonable to go ahead and
2 eliminate those balances as the State explores additional options for rooftop
3 solar. Otherwise it could be 15 years by the time we resolve those balances
4 through existing channels.

5 The Company believes its Tax Act proposal provides appropriate near- and
6 longer-term solutions that will lower customers' bills immediately from what
7 they would otherwise be and help offset future rate increases.

8 The Company is also proposing rates be set on a return on equity
9 ("ROE") of 10.50 percent.⁷ We have also proposed rates on a regulated
10 capital structure that includes a 53 percent equity component as supported by
11 Witness Sullivan.

12 **Q. PLEASE DESCRIBE THE NEED TO ADDRESS COAL ASH BASINS.**

13 A. For decades, along with other electric utilities across the country, DE
14 Carolinas followed industry practices managing and storing coal ash
15 consistent with regulations that evolved throughout that time. DE Carolinas
16 has become subject to both federal and state regulations that require it to take
17 additional significant actions to manage and permanently and safely close its
18 ash basins in ways that protect human health and the environment. In April
19 2015, the Environmental Protection Agency promulgated new rules regarding
20 the management and closure of ash basins. All of DE Carolinas' ash basins
21 must be closed under these rules. Like other utilities around the country
22 similarly affected by such regulation, the Company has begun the process of

⁷ As described in Witness Sullivan's testimony, while the Company fully supports Witness Hevert's testimony and analysis that yielded a recommended ROE of 10.75 as filed in this case, the Company is proposing rates which include a 10.50 percent ROE as a rate mitigation measure.

1 closing, or submitting plans to close, ash basins in accordance with these
2 regulations. Additionally, the Company is adding dry ash, bottom ash and
3 Flue Gas Desulfurization blowdown handling systems to our coal-fired plants
4 that are not already so equipped. We are also modifying all of our active and
5 decommissioned coal-fired plants to divert stormwater and low-volume
6 wastewater away from the basins.

7 As explained by Witness Smith, the Company is requesting recovery
8 of ash compliance costs in the amount of \$242 million over 5 years. These
9 costs were incurred from January 1, 2015 through September 30, 2018, plus
10 cost projected as of the time of this filing from October 1, 2018 to December
11 31, 2018. The Company is seeking recovery of these costs over a five year
12 period in order to mitigate customer rate impacts associated with these
13 significant compliance expenses. The Company expects to continue to invest
14 significant amounts related to coal ash compliance after the December 2018
15 cut-off in this case. However, instead of requesting recovery of an ongoing
16 level of these costs in this case, the Company is requesting the Commission
17 approve a continuation of the deferral for costs incurred beyond this case.

18 Witness Kerin provides significant detail on the prudence of the
19 Company's actions regarding ash basin creation, management and closure,
20 and he is the Company's subject matter expert in this area. Witness Wright
21 further speaks to the Company's actions related to coal ash and the regulatory
22 policy surrounding cost recovery. However, it's worth mentioning that for
23 decades, the Company has worked to provide electricity that is reliable, is

1 delivered using the best practices and latest technologies at the time, and is
2 available at reasonable rates. And for decades, reliable, affordable electricity
3 was made possible—nationwide—by coal. In its day, coal was king. It fueled
4 both a growing economy and population, along with demands for electricity
5 across South Carolina, meeting the energy needs of communities from the
6 mountains to the coast. It was the most advanced technology of its time.

7 With coal came coal ash – the by-product of decades of generating
8 electricity from this resource. In the early days, the best practice in the
9 industry was to let coal ash simply go out the top of the smokestack. Later,
10 changing regulations and industry best practices led to the use of emissions
11 control equipment and ash basins to dispose of coal ash, often in a pond-like
12 environment. Today, instead of being handled wet and stored in ponds, coal
13 ash is increasingly being handled dry and disposed of in lined landfills, or
14 beneficially recycled for use in construction products or as fill material in
15 place of dirt. In fact, Duke Energy recycled 78 percent of coal combustion
16 byproducts in 2017, and that includes DE Carolinas recycling or beneficially
17 re-using the ash that is produced at our coal-fired plants. We have retired half
18 of the coal-fired plants owned by Duke Energy in the Carolinas. And now, we
19 are closing all ash basins across the Carolinas in compliance with new,
20 sweeping state and federal laws and regulations, and as part of Duke Energy's
21 commitment to provide increasingly reliable, cleaner power to customers at
22 reasonable rates. Like any waste, we must ensure that coal ash is responsibly
23 managed, just as we have done with spent nuclear fuel.

1 As we transition to a smarter energy future by leveraging new
2 technology and cleaner power sources, we must remember the many benefits
3 coal has provided over the past several decades. Because our customers have
4 benefited from coal-produced electricity, the cost of responsibly managing
5 waste from consuming coal for electricity must also be borne by our
6 customers. This is an investment to help close out the coal era and push
7 forward to a new, cleaner energy future.

8 **Q. PLEASE DESCRIBE THE COMPANY'S GRID IMPROVEMENT**
9 **PLAN.**

10 A. From routine, day-to-day activities to powering high-tech manufacturing, the
11 electric power grid is the backbone of South Carolina's digital economy; – not
12 just today, but also 5, 10, 20 years in the future. As recent events have
13 reinforced, the Company must be ready for severe weather before it strikes,
14 and reduce the impact of storms that are worsening in frequency and intensity.
15 DE Carolinas must be vigilant and prepare now for the very real threat of
16 cyber and physical attacks. DE Carolinas also needs to provide more options
17 for customers to allow more control over the way they use electricity. And as
18 renewable energy technologies like solar energy, battery storage, micro-grids
19 and electric vehicles become more affordable and accessible; the Company
20 needs to take steps now to ready the grid to support the growth of these
21 technologies that are important to South Carolina's energy future.

22 The Company's Grid Improvement Plan addresses all of these needs,
23 while also managing costs. This Grid Improvement Plan was built using

1 advanced data analytics that helped identify strategic opportunities for
2 improvement. It also incorporates extensive input from customers, customer
3 and environmental advocacy groups and others who helped to refine this plan
4 to better serve their energy needs and the needs of our state. The Grid
5 Improvement Plan includes investments designed to strengthen the grid and
6 mitigate the impact of major storm events, as well as to harden and defend the
7 grid against critical physical and cybersecurity risks. Examples of the
8 Company's multi-layered improvements designed to protect the grid include:
9 updating grid technology including monitoring and communication
10 equipment; installing protective devices to limit access to critical systems and
11 minimize outages from physical or cyber-attack; and relocating, raising or
12 reinforcing equipment in flood-prone areas.

13 As discussed in the testimony of Witness Oliver, components of Duke
14 Energy's Grid Improvement Plan operationally fall into one of three
15 categories: (1) compliance-driven programs that protect the grid; (2) programs
16 that leverage advanced technologies to modernize the grid; and (3) projects
17 and programs that work to optimize customers' experience. We constructed
18 the Grid Improvement Plan, with stakeholder feedback, to address the risks
19 and opportunities that the analysis revealed. The Plan seeks to balance the
20 pace, scope, location, and timing of our work to address a diverse set of
21 customer and stakeholder needs. As we built the Grid Improvement Plan
22 proposed in this case, the Company has also kept the needs of our rural and
23 low-income customers in mind and sought to develop a strategy that

1 maximizes benefits to customers and the state, while keeping costs as low as
2 possible. The Company has sought out customer and stakeholder
3 perspectives, including multiple stakeholder workshops, as part of the process
4 before proposing this plan to the Commission.

5 **Q. PLEASE DESCRIBE THE INVESTMENT IN THE CUSTOMER**
6 **INFORMATION SYSTEM ("CIS")?**

7 A. At 30 years old, the Company's current CIS system is no longer supported or
8 upgradeable, and is unable to continue to be fully integrated into Duke
9 Energy's other systems. The new system will be complementary to future
10 technology, and includes the ability to interface with new smart meters to
11 enable customers to more easily start and stop service, ask questions about
12 their bills, view their usage, and allow the Company to identify the optimal
13 rate plan for each customer when asked. Customers expect greater access to
14 information about their account and energy use, and greater control over that
15 information. Through the consolidation of the older information systems into
16 a new information system, the Company will be able to deliver a customer
17 experience that will simplify, strengthen and advance our ability to serve our
18 customers in this digital age.

19 As explained by Witness Hunsicker, continued investment in an
20 antiquated technology platform is neither practical nor sustainable, and would
21 cost considerably more in the long run than replacing the system in its
22 entirety. Customer information systems, just like any other software solution,

1 periodically require replacement to deliver on capabilities required by
2 business operations, and more importantly, customers.

3 **Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S INVESTMENT**
4 **IN AMI?**

5 **A.** To bring customers additional choices and insight on their usage, we have
6 deployed AMI technology, including smart meters, in the service territory in
7 South Carolina. As explained by Witness Schneider, these smart meters will
8 work in tandem with many of our grid investments. Moreover, modern meters
9 will also provide crucial information to our CIS system, providing customers
10 greater control, convenience and choice over their energy usage, while also
11 giving customers the opportunity to budget, save time and save money. DE
12 Carolinas has approximately 590,000 smart meters installed as of September
13 2018, and deployment of AMI is virtually complete. These meters for South
14 Carolínians are being manufactured by South Carolínians employed by Itron
15 Inc. in Oconee County, South Carolina. The AMI technology will pave the
16 way for programs that will allow customers to stay better informed during
17 outages, control their due dates, avoid deposits, to be reconnected faster, and
18 to better understand and take control of their energy usage, and ultimately,
19 their bills.

20 **Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL FOR A FEE-FREE**
21 **CREDIT/DEBIT CARD PROGRAM.**

22 Currently, customer payments made by check, cash, free pay stations,
23 and Automated Clearing House, using bank drafts or paperless billing, are free

1 of charge. The costs for the Company to offer these methods are paid for by
2 all customers and not recovered exclusively by those specific customers that
3 use that method of payment. Residential customers using a credit or debit
4 card through any payment channel or a one-time ACH payment via phone or
5 on the Company's website are subject to a \$1.50 convenience fee. The
6 convenience fee is collected by the Company's third-party vendor, SpeedPay.
7 The Company receives no portion of this fee.

8 As customer expectations change and more payments are done
9 electronically, utility companies are beginning to offer fee-free payment
10 programs for their residential customers for all methods of payment. As
11 supported by the National Association of State Utility Consumer Advocates
12 (NASUCA) in Resolution 2012-07, "Urging Utilities to Eliminate
13 'Convenience Fees' for Paying Utility Bills with Debit and Credit Cards and
14 Urging Appropriate State Regulatory Oversight,"⁸ and as further explained
15 below, the Company believes it is reasonable to offer a fee-free payment
16 program for all payment methods to its residential customers, and recover the
17 costs associated with such a program from all customers through rates. The
18 requirement to pay a convenience fee when making a payment is one of the
19 largest frustrations customers experience. Customers have grown accustomed
20 to paying for other products and services with a credit card or debit card
21 without a separate, additional fee. Duke Energy Corporation has seen 10
22 percent average year over year growth in credit/debit card transactions over

⁸ <https://nasuca.org/2012-07-urging-utilities-to-eliminate-convenience-fees-for-paying-utility-bills-with-debit-and-credit-cards-and-urging-appropriate-state-regulatory-oversight/>

1 the past several years, and with this change we expect the growth rate to
2 double – so 20 percent more transactions in 2019 than in 2018. Eliminating
3 these fees for the Company's residential customers would provide additional
4 options for residential customers to pay their bills. As discussed in the
5 NASUCA Resolution 2012-07, additional fees for paying utility bills can be
6 burdensome to customers.

7 We also know that our customers want this option. The Company's
8 Customer Service department routinely receives inquiries about no-cost
9 electronic payment options. In the Company's 2018 Monthly Residential
10 Transaction Surveys, residential customers noted some of the following when
11 asked what they liked least about Duke Energy:

12 *"Not charge a fee for using a credit card."*

13 *"The fact that you can't pay online without being charged. Everybody*
14 *else has a free service to pay online."*

15 *"Take away the service charge. I just don't understand why you want*
16 *to charge somebody \$1.50."*

17
18
19 *"The only thing that I can say is I think they want to penalize you. If*
20 *you want to pay a certain way, they charge you extra."*
21

22 We think our customers will appreciate being able to use credit cards with the
23 Company the same way they can with other companies.

1 Q. IS THE COMPANY PROPOSING A FEE-FREE CREDIT/DEBIT
2 CARD PROGRAM FOR ITS COMMERCIAL AND INDUSTRIAL
3 CUSTOMERS AT THIS TIME?

4 A. Not at this time. Because commercial and industrial customers generally have
5 more methods in which to pay, and their average payment amount is
6 significantly higher than residential (which leads to higher processing costs),
7 at this time the Company is not proposing a fee-free program for commercial
8 and industrial customers.

9 IV. CUSTOMER LANDSCAPE

10 Q. CAN YOU PUT DE CAROLINAS' RATES INTO PERSPECTIVE?

11 A. Yes. First, we believe that electricity in South Carolina remains an excellent
12 value, even with our proposed adjustment. Over the past year, gas prices, a
13 basic consumer good, is up 3.5 percent. However, the cost of electricity in the
14 Southeast has dropped 2.6 percent from September 2017 to September 2018.
15 Electricity provides fundamental value to our daily life by powering
16 appliances, heating and cooling homes, cooking food and allows us to use our
17 televisions, computers, charging devices such as tablets and smartphones and
18 other devices that are now a common part of our everyday lives. Even with
19 DE Carolinas' proposed rate adjustment our customers will continue to pay
20 rates below the national average and competitive with other utilities in our
21 region.

1 **Q. IS THE COMPANY PROACTIVELY EDUCATING CUSTOMERS**
2 **ABOUT ITS PROPOSALS IN THIS CASE?**

3 A. Yes. DE Carolinas is committed to being transparent and keeping customers
4 informed about the costs included in their bills and proposals to adjust rates.
5 The Company has engaged in Grid Workshops to describe and help shape our
6 Grid Improvement Plan, and we regularly publicly communicate about our
7 environmental compliance work. We have also been very transparent about
8 our investments to build a smarter energy future for our customers powered by
9 cleaner, more efficient energy sources such as highly efficient natural gas,
10 carbon-free nuclear energy, renewable resources like hydroelectric generation
11 and solar energy.

12 Now that the Company's request has been filed, DE Carolinas will
13 utilize a section of the Duke Energy website to include videos, fact sheets and
14 direct information about the components of this case. In addition to the
15 website, the Company has and will continue to inform and educate our
16 customers as well as those community facing employees who interact with
17 their customers about our request.

18 **Q. HAS THE COMPANY CONTINUED ITS ONGOING EFFORTS TO**
19 **MITIGATE CUSTOMER RATE IMPACTS?**

20 A. Yes. The Company relies on a variety of fuel sources to generate power and
21 has prudently managed its operating costs. This fuel diversity allows DE
22 Carolinas to choose how to generate electricity – day by day, hour by hour –
23 based on the cost of the fuel needed to run its different plants. DE Carolinas

1 has managed its costs through continuous improvement to its operations
2 (thereby benefitting customer through efficiency-derived controlled costs) as
3 well as through significant cost containment policies and activities.

4 The Company is also committed to performance excellence, and has
5 been recognized for it and the cost savings it brings. For example, DE
6 Carolinas' three nuclear plants exceeded 92.5 percent capacity factor, and the
7 company recorded the 2nd highest net annual output, falling just short of the
8 generation record established in 2016 and providing 62 percent of the
9 Company's total power generation during the period. Also, as explained by
10 Witness Capps, I am proud that Duke Energy has been recognized by the
11 Nuclear Energy Institute ("NEI") multiple times with Top Industry Practice
12 ("TIP") awards. In 2015, the Company's Excellence in Cost Management
13 program received an award for Vision, Leadership and Ingenuity. This
14 program was developed and designed in response to the competitive economic
15 pressures facing nuclear plants nationwide. The goal is to enhance
16 sustainability in cost savings along with fleet performance. The recognition
17 took note that Duke Energy saved more than \$35 million in 2014 while
18 increasing worker safety, innovation and employee engagement. In 2017, the
19 Company's nuclear procurement engineering organization won a TIP award
20 when they developed two applications that were implemented fleet-wide in
21 March 2016 and that increase nuclear safety by ensuring procurement
22 engineering and quality receipt activities are correctly prioritized to support
23 critical work activities and schedules.

1 Q. WHAT OTHER INITIATIVES HAS THE COMPANY IMPLEMENTED
2 TO HELP ITS CUSTOMERS REDUCE THEIR ELECTRICITY
3 BILLS?

4 A. Duke Energy wants to help customers understand their energy use,
5 empowering them to save money on their electric bill. DE Carolinas is
6 continuing to expand and enhance its portfolio of demand-side management
7 ("DSM") and energy efficiency ("EE") programs because these programs
8 have proven to be one of the most effective means to reduce energy costs,
9 offset the need for new power plants, and protect the environment. DE
10 Carolinas' already robust portfolio of EE programs is designed to provide
11 offerings that engage and educate customers around their energy usage and
12 efficiency, as well as empower them with financial incentives to invest in
13 efficiency improvements. Duke Energy offers customers more than a dozen
14 energy-saving programs for every type of energy user and budget. The
15 Company's EE programs currently save its customers in the Carolinas 4.3
16 billion kWh annually or more than \$357 million, which is about 5.4 percent of
17 total retail kWh sales. Combined, its DSM and EE programs offset capacity
18 requirements by the equivalent of more than seven power plants. The
19 Company's growing portfolio of DSM programs, which are designed to
20 manage customer demand for electricity, further offer customers opportunities
21 to lower their bills by providing them with financial incentives in exchange
22 for shifting the timing of their electricity use from peak to non-peak periods,

1 thereby helping the Company to reduce fuel costs during the periods when
2 energy costs the most to produce.

3 The Neighborhood Energy Saver Program is a residential EE program
4 targeted at low-income customers that includes the direct installation of a
5 number of EE measures. DE Carolinas has implemented the program utilizing
6 a neighborhood engagement, door-to-door strategy. Through the program, a
7 comprehensive package of EE measures is installed at no direct cost to the
8 customer. Since its inception, we've helped more than 10,700 DE Carolinas
9 customers in South Carolina save nearly 1.3 million kWh each year through
10 2017. This means the average household could save more than \$45 per year
11 on energy costs. Equally important, each participating household is given
12 information and education along with EE tips and information about other
13 programs that can help them reduce their bills.

14 **Q. ARE THERE PROGRAMS IN PLACE TO OFFER FINANCIAL**
15 **ASSISTANCE TO YOUR CUSTOMERS?**

16 **A.** Yes. We know that for many customers, any savings on their power bill can
17 make a big difference in their monthly budget. Share the Warmth is an
18 assistance program for DE Carolinas customers in need, helping low-income
19 individuals and families cover home energy bills. Eligibility is determined by
20 the county Department of Social Service (DSS) agencies. The Share the
21 Warmth program is funded by contributions from customers, employees, and
22 the Duke Energy Foundation. DE Carolinas customers are able to add a one-
23 time or recurring contribution to their bills. Since its inception, the Share the

1 Warmth program has provided approximately \$8.6 million in assistance to DE
2 Carolinas' customers in South Carolina. We have also made it easier for
3 assistance agencies to make commitments to help financially challenged
4 customers with their bills through use of our agency portal.

5 The Company also offers optional bill management programs designed
6 to assist eligible customers in either managing fluctuations in their monthly
7 bill or who are having difficulty paying their entire bill by the due date.

8 **Q. WHAT OTHER COMPANY EFFORTS ARE UNDERWAY TO ASSIST**
9 **CUSTOMERS WITH THEIR ABILITY TO PAY?**

10 A. Duke Energy is committed to helping all customers keep their accounts and
11 their service in good standing. Often, simply spreading energy costs equally
12 over time can help customers manage their costs and pay their bills. Payment
13 plans are important not only to low-income customers, but to other residential
14 customers who may have had to adjust their household budgets. DE
15 Carolinas' Equal Payment Plan allows customers to spread out the impacts of
16 seasonal fluctuations into twelve equal monthly payments. The Company also
17 offers payment arrangements in South Carolina to customers unable to pay
18 their bill by the past due date. Payment arrangements can help customers
19 avoid interruption of service and help them re-establish control over their
20 payments.

21 The Company is also leveraging technology to make the payment
22 arrangement process accessible for customers. Customers can make an
23 agreement by telephone or via the Company website using a tool that is quick

1 and objective based on their individual account attributes. This solution
2 provides the customer with payment options and allows the use of our
3 automated system or website without having to discuss their account with a
4 specialist. The self-serve and equal payment options help the Company
5 manage customer service costs while providing fast and efficient service to
6 customers whose service may be subject to disconnection. We know that self-
7 service does not work for all customers, so customer service specialists are
8 still available to discuss payment options and review accounts with
9 extenuating circumstances.

10 The Company has also developed and implemented several other
11 programs including a free customized home energy report to inform and assist
12 with lowering our customers' consumption through energy efficiency. Home
13 Energy House Call is a free in-home energy assessment, valued at \$180,
14 which provides customers living in single family homes with information
15 about their unique energy use and steps they can implement to become more
16 energy efficient. A certified expert checks the home for air leaks, examines
17 insulation levels, checks appliances and more. In addition, customers receive a
18 free energy efficiency starter kit, containing efficiency measures valued at
19 approximately \$30, to help them start saving right away. DE Carolinas'
20 Residential Multi-family Energy Efficiency Program ensures that customers
21 living in multi-family residences also have opportunities to save by providing
22 multi-family residents with electric water heaters. These EE measures are
23 provided at no direct cost to the customer and are installed by the Company.

1 In addition, the High Bill Alerts program was implemented for DE
2 Carolinas customers in South Carolina. The program proactively notifies
3 customers via email when their forecasted electricity consumption cost for
4 their next bill is 30 percent or \$30 higher than their previous month's bill. The
5 Company also offers a Lower My Bill Toolkit, which in five easy steps helps
6 the customer track their energy usage and reduce energy costs.

7 **Q. HOW HAS THE COMPANY FOCUSED ON DELIVERING**
8 **EXCELLENT CUSTOMER SERVICE?**

9 A. We are working every day to explore new ways to enhance the customer
10 experience. Customer satisfaction ("CSAT") is a key focus area for DE
11 Carolinas. The Company operates a robust CSAT program, which includes
12 both national benchmarking studies and proprietary transaction and
13 relationship CSAT studies. Results from these studies are analyzed in vigorous
14 quarterly data review sessions, with findings driving improvements to
15 processes, technology and behaviors – all in an effort to continuously improve
16 CSAT. The 2018 J.D. Power Electric Utility Customer Satisfaction Study
17 ranked DE Carolinas in the top quartile for performance in all categories
18 (Power Quality and Reliability, Price, Billing and Payment, Corporate
19 Citizenship, Communications, and Customer Service).

20 DE Carolinas measures overall customer satisfaction and perceptions
21 about the Company in our proprietary relationship study, the "Customer
22 Perceptions Tracker." Feedback is requested from residential and
23 small/medium business customers, and all large business electric customers,

1 to better understand their customer experience with Duke Energy and overall
2 perceptions of the Company. Duke Energy SC Residential satisfaction scores
3 are up four points on average from 2014.

4 In addition to our relationship study, DE Carolinas utilizes Fastrack,
5 the Company's proprietary transaction study, to measure overall customer
6 satisfaction with our operational performance (i.e. responding to and resolving
7 customer service requests.) Each year, thousands of interviews are conducted
8 with our customers by a third-party research supplier upon the completion of
9 the customer's service request. The survey questions cover the entire
10 experience, from the time the customer picks up the phone to contact the
11 Company or submits a service request online, until the issue is resolved and
12 the truck drives away from the customer's property. Analysis of these ratings
13 helps to identify specific service strengths and opportunities that drive overall
14 satisfaction and to provide guidance for the implementation of process and
15 performance improvement efforts. Through mid-2018, roughly 79 percent of
16 Duke Energy Carolinas residential customers express high levels of
17 satisfaction with these key service interactions (Start/Transfer Service (88
18 percent), Outage/Restoration (81 percent), and Street Light Repair (67
19 percent).

20 Also, in 2017, 'Customer Satisfaction' continued as one of a select
21 number of goals included in the annual incentive compensation plans for DE
22 Carolinas employees. By connecting customer satisfaction directly to
23 compensation, each employee is "invested" in improving and maintaining

1 high customer satisfaction for all Duke Energy utilities, including DE
2 Carolinas. Results are monitored at the enterprise level, state level, and by
3 customer segment, so problems can be identified and corrected. This also
4 allows the Company to identify and apply best practices across all of our
5 jurisdictions.

6 We also continue to enhance our customer service practices to address
7 language, cultural and disability barriers. Among other accommodations, the
8 Company's customer service center offers customer service and
9 correspondence in Spanish, handles calls from TTY devices (text telephones),
10 offers bills in Braille, and accepts pledges to pay from social service agencies.

11 **V. ECONOMIC DEVELOPMENT AND EDUCATION EFFORTS**

12 **Q. DOES DE CAROLINAS VIEW ECONOMIC DEVELOPMENT AS A**
13 **VITAL PART OF ITS BUSINESS?**

14 **A.** Yes. Making smart investments in energy infrastructure can help to attract
15 business and industry, bring good jobs to the state, and promote smart growth
16 and economic prosperity across South Carolina. It takes investment to
17 provide the reliability our customers expect – investment in power plants,
18 poles and wires, substations and meters. But all of that investment provides
19 critical infrastructure that supports businesses and jobs, schools and
20 universities, stores and the products consumers purchase, and a foundation to
21 ensure the future remains bright for communities across the State. Over the
22 last century, Duke Energy has invested millions of dollars into local
23 economies across the state. When a new power plant is built or transmission

1 line constructed, it creates jobs and results in money spent at the local level
2 while creating a tax base that supports local infrastructure and services.
3 Economic development efforts are critical to retaining and growing the
4 industrial base and manufacturing load so that the state can experience
5 continued job growth and economic success. This helps keep electric rates
6 competitive and mitigates rate increases by enabling costs to be spread across
7 a larger customer base.

8 **Q. PLEASE DESCRIBE THE COMPANY'S ECONOMIC**
9 **DEVELOPMENT EFFORTS IN SOUTH CAROLINA.**

10 A. DE Carolinas has an Economic Development team responsible for retaining
11 and supporting expansion opportunities for existing customers while also
12 targeting potential new customers and supporting efforts to recruit them to the
13 service area. In addition to coordinating with, or participating in, statewide or
14 community task forces or initiatives, the team works with businesses on site
15 selection and expansion opportunities. Since 2005, 54 sites totaling over
16 23,831 acres in the Duke Energy Carolinas' South Carolina service territory
17 have participated in Duke Energy's Site Readiness Program. The Duke
18 Energy Site Readiness Program is intended to identify, assess, improve, and
19 increase awareness of industrial sites in Duke Energy's service territories.
20 The program also offers a matching grant of up to \$10,000 to implement
21 improvements to viable sites. Currently there are 13 major projects
22 constructed on sites that went through the program, resulting in over 2,548
23 new jobs and over \$900 million in capital investment.

1 The Company's ongoing Carolinas Investment Fund also provides
2 support for projects in the Carolinas service area aimed at recruiting new
3 industry, retaining existing jobs, and expanding existing customer operations,
4 by partnering with state or local economic development organizations to
5 provide appropriate incentives. These projects typically include site or
6 building development and related infrastructure or other site preparation
7 requirements. The grants from the Carolinas Investment Fund serve as
8 important discretionary supplements to incentives offered by the state or local
9 entities. To qualify for the grants the recipient must create certain numbers of
10 new jobs or make capital investments, subject to minimum dollar amounts.
11 Since 2013, DE Carolinas has contributed to the creation of more than 9,940
12 jobs in South Carolina and approximately \$4,837 million in capital
13 investments.

14 Much of this effort has been aimed at encouraging new industrial
15 investments. We believe a healthy industrial base is good for all of our
16 customers. As new manufacturing businesses are established and existing
17 manufacturing businesses expand, they typically create a significant multiplier
18 effect that directly and indirectly produces additional jobs and investments.
19 However, our efforts for economic development are not focused solely on
20 industrial customers.

21 Training and recruiting a highly skilled workforce is also essential to
22 maintaining the competitiveness of our region. Over the last 3 years, Duke
23 Energy has invested almost \$500,000 to support the development, promotion,

1 and delivery of workforce training programs through South Carolina's
2 Technical and Community Colleges. We are confident that our sustained
3 economic development efforts will continue to provide positive results here in
4 South Carolina and benefit customers by keeping rates competitive over the
5 long term through an increased customer base served by our plant investment.

6 **VI. POWERING THE FUTURE**

7 **Q. DO THE FUTURE PLANS OF THE COMPANY SUPPORT THE**
8 **ECONOMIC DEVELOPMENT PROSPECTS IN SOUTH CAROLINA?**

9 A. Yes. Our infrastructure and CIS investments will help power the future in
10 South Carolina, not only for the economy as a whole, but the manner in which
11 our customers will consume, monitor and manage their electricity
12 consumption. While we have come a long way in modernizing our generation
13 systems, we now need to focus similarly on our grid, metering and
14 information technology systems. These investments are important for us to
15 continue reliably serving customers in the future. I discuss these investments
16 below. While all of these investments are not included in this case, it's
17 important to share our vision of a smarter energy future.

18 **Q. PLEASE DESCRIBE HOW THE COMPANY WILL BUILD A**
19 **SMARTER ENERGY FUTURE.**

20 A. The grid is the backbone of the new digital economy. South Carolina is
21 served through a multi-state electric system that includes 13,100 miles of
22 transmission lines, more than 100,000 miles of underground distribution lines,
23 and more than 1,600 substations. For the DE Carolinas distribution system,

1 approximately 2,970 distribution line miles and 23,700 transformers were
2 added over the last five years. As one of the fastest growing states in the
3 nation, South Carolina's population now tops 5 million and we are projecting
4 over 400,000 more, or a 9 percent increase by the year 2030. That's creating
5 real demands on our grid.

6 The Grid Improvement Plan proposed in this case is a long-term
7 initiative, and the Company has provided its multi-year plan built upon
8 strategic, data-driven investments to improve reliability to avoid outages and
9 speed restoration; harden the grid to protect against cyber and physical threats;
10 expand solar and other innovative technologies across a two-way, smart-
11 thinking grid; and give customers more options and control over their energy
12 use and tools to save money. The Company proposes additional rate changes
13 in 2020 and 2021 to reflect the remaining years of the multi-year plan, with
14 costs captured in a regulatory asset for recovery between rate changes.

15 Not only does Duke Energy employ thousands of workers in the State,
16 it also supports an extensive local supply chain that extends to virtually every
17 county in South Carolina. In addition, the Grid Improvement Plan that Duke
18 Energy has recently committed to in South Carolina will not only add to the
19 economy of South Carolina, it will help to avert economic losses that result
20 from unplanned outages. We commissioned economic research prepared by
21 Joseph C. Von Nessen, Ph.D. "The Economic Impact of Duke Energy: A
22 Statewide and Regional Analysis"⁹ that indicates the following: (1) The
23 annual economic impact of Duke Energy on the state of South Carolina totals

⁹ http://www.resh.com/Von_Nessen_Duke_SC_EIS_Nov2018_FDa.pdf

1 approximately \$6.6 billion. This figure reflects the dollar value representing
2 all final goods and services produced in South Carolina that can be attributed
3 (either directly or indirectly) to Duke Energy. This impact corresponds to
4 15,189 jobs and \$969.4 million in labor income that would not exist
5 otherwise. (2) This \$6.6 billion impact extends to every county in South
6 Carolina, with the highest impacts occurring in the counties of York (\$1.1
7 billion), Oconee (\$1.1 billion), Greenville (\$838.3 million), Darlington
8 (\$756.8 million), and Spartanburg (\$686.4 million). The magnitude of the
9 Grid Improvement Plan on South Carolina's economy is roughly equivalent to
10 a new major automotive manufacturing plant locating in the State.

11 **VII. CONCLUSION**

12 **Q. WHAT IS THE KEY OBJECTIVE OF THE COMPANY'S**
13 **REQUESTED GENERAL RATE ADJUSTMENT?**

14 **A.** The Company's most important objective is to continue providing safe,
15 reliable, affordable, and increasingly clean electricity to our customers with
16 high quality customer service, both today and in the future. Our request for a
17 rate increase is made to support investments that benefit our customers while
18 preserving the Company's financial position. We strive to ensure that those
19 investments are made in a cost-effective manner that retains the level of
20 service and competitive rates for our customers.

21 **Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

22 **A.** Yes.

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[PURSUANT TO PREVIOUS INSTRUCTION, THE
PREFILED REBUTTAL TESTIMONY OF KWODO
GHARTEY-TAGOE FOLLOWS HEREINAFTER]

VOLUME 4
3/21/19

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

**BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA**

DOCKET NO. 2018-319-E

In the Matter of:	)	
	)	REBUTTAL TESTIMONY OF
Application of Duke Energy Carolinas, LLC	)	KODWO GHARTEY-TAGOE
for Adjustments in Electric Rate Schedules	)	FOR DUKE ENERGY
and Tariffs and Request for an Accounting	)	CAROLINAS, LLC
Order		

I. INTRODUCTION

1 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT**
2 **POSITION.**

3 **A.** My name is Kodwo Gharthey-Tagoe, and my business address is 40 West Broad
4 Street, Greenville, South Carolina 29601. I am State President – South Carolina
5 for Duke Energy Carolinas, LLC (“DE Carolinas” or “Company”) and Duke
6 Energy Progress, LLC (“DE Progress”), both of which are wholly owned
7 subsidiaries of Duke Energy Corporation (“Duke Energy”).

8 **Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS**
9 **PROCEEDING?**

10 **A.** Yes.

II. PURPOSE AND SCOPE

11
12 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

13 **A.** The purpose of my rebuttal testimony is to provide an overview of the Company’s
14 rebuttal case.

15 **Q. WHO ARE THE OTHER WITNESSES PROVIDING REBUTTAL**
16 **TESTIMONY?**

17 **A.** The Company’s other witnesses filing rebuttal testimony in this case are:

18 1. **Kim H. Smith**, Director of Rates and Regulatory, who responds to the
19 recommendations of the South Carolina Office of Regulatory Staff (“ORS”) on
20 certain accounting and ratemaking adjustments. Witness Smith also responds to
21 the ORS’ recommendations with regards to deferred costs. Witness Smith

1 explains the deferrals in this case include carrying costs that are necessary to
2 ensure the Company recovers the full cost and effect of the deferral.

3 2. **Steven Capps**, Senior Vice President of Nuclear Operations. Witness
4 Capps' rebuttal testimony examines the establishment of end of life nuclear
5 reserve, reiterates that the estimates used to calculate end of life nuclear reserve
6 were appropriate, and why end of life nuclear reserve is in the best interest of
7 today's customers.

8 3. **John Sullivan**, Director, Corporate Finance and Assistant Treasurer,
9 explains his recommendation of updating the cost of long-term debt by proposing
10 a new rate of 4.53 percent, based on the actual cost of debt as of December 31,
11 2018, and further responds on the Company's view of the recommendations
12 concerning cost of capital.

13 4. **David L. Doss Jr**, Director of Electric Utilities and Infrastructure
14 Accounting, responds to testimony filed by South Carolina Energy Users
15 Committee regarding the appropriate accounting for retirement obligations related
16 to coal ash. He explains that the Company properly adhered to accounting
17 guidance and appropriately began its Asset Retirement Obligation ("ARO")
18 accounting for coal ash costs upon being subject to legal obligations that triggered
19 those requirements.

20 5. **Janice Hager**, President of Janice Hager Consulting, LLC. Witness
21 Hager's rebuttal responds to testimony filed by Vote Solar, South Carolina State
22 Conference of the National Association for the Advancement of Colored People,
23 South Carolina Coastal Conservation League, Upstate Forever, and Hasala

1 Dharmawardena regarding their concerns in using the minimum system concept
2 to allocate distribution costs as customer related costs in Duke Energy Carolinas
3 Cost of Service Studies. Witness Hager also addresses the allocation of Advanced
4 Metering Infrastructure meter costs and uncollectible costs as customer related
5 costs. Finally, she addresses the composite allocator used for the Grid
6 Improvement Plan.

7 6. **Robert B. Hevert**, Partner at ScottMadden, Inc., provides model results
8 and quantitative and qualitative data throughout his rebuttal testimony to confirm
9 his original recommendation of a 10.75 percent Return on Equity ("ROE"), and
10 responds to other issues affecting ROE, and reiterates that the Company's
11 proposed ROE of 10.50 percent is a more than reasonable request.

12 7. **Retha Hunsicker**, Vice President, Customer Connect-Solutions, explains
13 that the projected two-year average operating and maintenance expense for the
14 Customer Connect Program was derived from a disciplined process of using
15 known expenses, such as fixed fee contracts, professional services, change
16 management, and training to calculate overall program costs, and that the
17 Company's proposed expenses are appropriate to include in rates as known and
18 measurable expenses.

19 8. **Jon F. Kerin**, Vice President, Coal Combustion Products Operations,
20 Maintenance and Governance, responds to the ORS and South Carolina Energy
21 Users Committee's proposed disallowance of costs that the Company has
22 prudently incurred in closing ash basins in both North Carolina and South

1 Carolina. Kerin discusses the shared costs and benefits of the generation serving
2 DE Carolina's customers across state lines.

3 9. **Dr. Julius (Chip) Wright, Ph. D**, Managing Partner at J. A. Wright &
4 Associates, LLC, addresses several issues in regards to the cost recovery
5 disallowances for costs associated with coal combustion residuals as presented by
6 the ORS including: additional costs related to North Carolina laws and
7 regulations, litigation expenditures and accounting treatment of deferred costs.
8 Witness Wright also responds to the claim by South Carolina Energy Users
9 Committee that the Company's coal ash related costs are much higher than other
10 electric utilities and to the recommendation by the Sierra Club that recovery of
11 Coal Combustion Residuals ("CCR") expenses be conditioned on the Company's
12 completion of a retirement analysis. Witness Wright also addresses several other
13 policy issues present in this case.

14 10. **Jay W. Oliver**, General Manager of Grid Solutions Engineering and
15 Technology, responds to concerns regarding the Company's proposed Grid
16 Improvement Plan. Witness Oliver groups his response into three principal
17 issues: the request for a separate proceeding for reviewing the Company's Grid
18 Improvement Plan ("GIP"), the request for more information regarding the
19 benefits that the proposed GIP will provide, and the need for a more detailed GIP
20 design.

21 11. **Michael J. Pirro**, Director of Southeast Pricing and Regulatory Solutions,
22 addresses several concerns posed by the intervenors including: the Basic Facilities
23 Charge; the recommended rate class returns; Advanced Metering Infrastructure

1 ("AMI") enabled rate designs; the GIP; the refunding of revenues under the
2 Excess Deferred Income Tax Rider; and the Company's Hourly Pricing rate
3 schedule.

4 12. **Steve Immel**, Vice President of Fossil Hydro Operations, addresses the
5 recommendation by the Sierra Club to request that the Company perform a
6 comprehensive economic analysis before making capital investments at the
7 Company's coal-fired stations. As Witness Immel outlines in his testimony,
8 mandating the performance of retirement analyses prior to Company decisions to
9 make capital improvements limits the Company's ability to use its best judgment
10 and experience to manage its generation fleet.

11 13. **Renee Metzler**, Managing Director for Retirement and Health and
12 Welfare, responds to ORS proposed disallowances related to compensation and
13 employee engagement related expenses. Witness Metzler explains how
14 consideration of the various components of total compensation in isolation
15 ignores the Company's obligation to be responsive to the market for talent and
16 assure the competitiveness of the total compensation package. Witness Metzler
17 demonstrates that the proposed disallowances of items like contribution awards,
18 lump sum merit increases, service and safety awards, along with other employee
19 benefits, are inappropriate and should be rejected by the Commission.

20 14. **Lesley Quick**, Vice President of Revenue Service, discusses the need to
21 include the Company's growth projections in the proposed adjustment for
22 credit, debit and ACH payment expenses. Witness Quick also addresses the
23 request to publicly provide monthly detailed data for residential customers and

1 low-income customers, citing that the level of detail the Company currently
2 provides pertaining to service disconnects is sufficient.

3 **III. REBUTTAL TESTIMONY**

4 **Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S REBUTTAL**
5 **CASE.**

6 A. When I consider the positions taken by the ORS, I'm concerned about the effect
7 of its position on the Company's financial condition, which directly affects our
8 ability to provide safe, clean, reliable electricity to our customers. There are
9 many contradictions in the ORS case which concern me, as I explain below and as
10 other witnesses address in this case. The ORS consultant and witness Dan Witliff
11 departs from the historic practice of allocating costs between South Carolina and
12 North Carolina. Historically, all of the Company's generation costs are allocated
13 between the two states, as well as fuel costs and associated costs. Now, the ORS
14 proposes to disallow certain environmental compliance costs due to the ORS's
15 view of a North Carolina law. This is a concerning position, and could result in
16 more costs being allocated to South Carolina, as explained by Company Witness
17 Dr. Wright. North Carolina generally pays 70 percent of the Company's costs – if
18 North Carolina took the same view as South Carolina, there could be a
19 monumental cost shift to customers in this State.

20 I also see a contradiction in the ORS position that attempts to devalue and
21 effectively disallow the costs the Company has incurred to finance deferred costs.
22 The ORS takes this position but yet argues that it is allowing the Company full
23 cost recovery, which is not the case as explained by Company Witness Smith and

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1 others in this case. This view is even more contradictory in that ORS Witness
2 Parcell suggests lowering the allowed return on equity in this case based on such
3 deferrals, but then the ORS argues to reduce such deferrals. That is not logically
4 consistent. As to the ROE proposed by the ORS, I'm concerned with their
5 proposal to set such a low ROE, and that in doing so they are ignoring the ROEs
6 of similarly situated utilities as explained by Witnesses Hevert and Sullivan.

7 I am also concerned about the disallowance recommendation from ORS
8 related to community organizations, employee compensation and employee
9 recognition and engagement expenses. No one has challenged our overall salary
10 levels, rather the ORS proposes to disallow compensation based on how we pay,
11 versus what we pay. Only looking at one piece of employee compensation, as the
12 ORS has done, ignores the Company's obligation to be responsive to the market
13 for talent and assure the competitiveness of the total compensation package,
14 consisting of base salary, cash based incentives, long-term incentive
15 compensation, retirement and other benefits. Similarly, we need to keep
16 employees engaged and trained. Our employee programs enhance and reinforce
17 employee engagement and/or reduce overall costs. Business units with more
18 engaged employees have lower levels of turnover and absenteeism and higher
19 levels of productivity and customer satisfaction. Using employee engagement
20 programs as a means of retaining critical skills benefits customers through higher
21 service levels and lower turnover costs. Experienced, engaged employees that are
22 incentivized to remain with the Company and work in a safe manner while

1 emphasizing high service levels benefit our customers. Company Witness
2 Metzler addresses these topics in more detail.

3 I was pleased to see that no party contested our proposal to eliminate
4 credit card fees, but I was disappointed that our adjustment to recover the uptick
5 in customer subscription was opposed by ORS. Company Witness Quick
6 addresses this in more detail, but the use of credit cards for no additional fee is a
7 constant wish of our customers that we are ready and willing to meet, but we
8 should not be harmed by meeting that need.

9 Finally, two other issues are of great concern to me. The first is the
10 apparent misunderstanding regarding the Company's Basic Facilities Charge. We
11 have proposed a cost based charge—that would allocate to each customer the
12 costs to have the infrastructure available to serve them. Any costs that are in the
13 Basic Facilities Charge are not included in the variable rate component of the rate
14 schedule. Parties seem to assume the change in the Basic Facilities Charge is
15 additive—it is not. Moreover, this charge ensures that other customers are not
16 subsidizing low usage customers, such as customers with vacation or second
17 homes. Recovery of all customer related costs through the Basic Facilities
18 Charge reduces bills from what they would otherwise be in very hot summer
19 months and very cold winter months. Nonetheless, as Company Witness Pirro
20 explains, if the change is considered too great we have proposed an alternate
21 approach with a more gradual increase to the Basic Facilities Charge and to
22 reinstate the remaining costs back into the variable component.

1 The second issue I'd like to address is the strong reaction we have seen to
2 our Grid Improvement Plan. While parties may want more time to understand the
3 plan over and above the stakeholder engagement sessions that we started this
4 summer, we believe we have met our evidentiary burden in this case. However,
5 should the Commission wish to open a separate docket, the Company is willing to
6 do so provided that the Commission extends its previous deferral Order No. 2018-
7 751 during the pendency of the proceeding until the Company can come back for
8 a rate proceeding to address cost recovery. Extension of that deferral does delay
9 cost recovery past what the Company proposed in this case, but given multiple
10 parties' advocacy on this issue, that could be a fair and reasonable resolution to
11 the concerns in this docket.

12 **Q. DOES YOUR SUMMARY OR TESTIMONY ADDRESS ALL ISSUES IN**
13 **THIS CASE?**

14 A. No, my testimony is designed to provide an overview of our rebuttal case, but I
15 have not attempted to capture them all in my testimony. Our witnesses address
16 additional topics on a case by case basis.

17 **Q. PLEASE ADDRESS THE COMPANY'S RESPONSE TO PROPOSED**
18 **DISALLOWANCES FOR ENVIRONMENTAL COMPLIANCE COSTS.**

19 A. In its testimony, the ORS dangerously suggests that the Commission should not
20 approve any costs that the Company incurred to comply with the Coal Ash
21 Management Act ("CAMA") in North Carolina under the apparent theory that
22 South Carolina customers should only receive the benefits of sharing power
23 generation assets with North Carolina but pay none of the costs that the Company

1 has to incur to comply with North Carolina laws and policies. In direct
2 contradiction to its own position, however, ORS suggests that North Carolina
3 customers should absolutely pay for the costs that the Company has to incur to
4 comply with the laws and policies of South Carolina. The inequity of ORS's
5 position is apparent.

6 Additionally, the ORS is factually incorrect when it suggests that CAMA
7 has imposed additional expenses on South Carolina customers. To the contrary,
8 the coal ash beneficiation requirements in CAMA will actually provide South
9 Carolina customers millions of dollars in net savings, all of which would have to
10 be refunded to North Carolina customers if their ill-conceived proposal to reject
11 CAMA is accepted. Moreover, if ORS's position is taken to its logical
12 conclusion, it would call into question the continued wisdom of sharing assets and
13 economies of scale across jurisdictional boundaries, a result that would harm all
14 customers with higher prices and the costs of uneconomic duplication of assets.
15 These dire consequences are discussed in more detail by Company Witnesses
16 Kerin and Wright.

17 Witnesses Kerin and Wright also address the unsubstantiated claim by
18 SCEUC Witness O'Donnell to disallow 75 percent of these costs. This proposal
19 is so reckless and unsubstantiated that it should be summarily rejected by the
20 Commission.

1 Q. PLEASE ADDRESS THE COMPANY'S RESPONSE TO ORS'S
2 PROPOSED DISALLOWANCES RELATED TO DEFERRED BALANCES.

3 A. The ORS does not raise any imprudence allegations regarding the Company's
4 actions relative to expenses included in deferred balances; it simply ignores that
5 the timeliness of cost recovery matters and that the Company must finance the
6 deferred balances. The ORS proposes stretching out certain deferred costs over
7 extended periods of time without recognizing the the costs to finance the balances
8 during that period. Although we are generally not in dispute over the underlying
9 actions which resulted in the deferred balances, ORS takes a drastic position on
10 the return on those balances during the deferral period and amortization periods to
11 somehow suggest that the Company is profiting from delayed recovery of costs.
12 This is not the case. The Company is trying to recover its carrying costs on the
13 value of money based upon our financing structure. The Company's financing is
14 made up of both debt and equity, and to ignore the way the Company finances its
15 costs will cause grave concern to investors as articulated by Company Witness
16 Hevert. It would also, depart from good regulatory practice as explained by
17 Company Witness Dr. Wright, and have other negative implications as explained
18 by Company Witness Smith. I also see a contradiction in ORS's position, because
19 at the same time the ORS proposes to effectively disallow deferred costs (without
20 any allegation of imprudence), the ORS cost of equity witness relies upon the
21 deferrals to arbitrarily attempt to lower the Company's cost of capital. It is a
22 contradiction to rely upon those deferrals in one witness's recommendation, but
23 then cut them in another.

1 Q. PLEASE ADDRESS THE COMPANY'S REACTION TO THE PROPOSED
2 ROE OFFERED BY ORS WITNESS PARCELL.

3 A. We are also concerned about the cost of capital proposed by ORS. We agree on
4 capital structure, but we have one correction to the actual 12/31/2018 debt rate as
5 explained by Company Witnesses Sullivan and Smith in their rebuttal testimonies.
6 As to the return on equity proposed by ORS, both Mr. Hevert and Mr. Sullivan
7 explain that the Company competes for capital with other vertically integrated
8 electric utilities, its ROE proposal is generally in line with authorized ROEs
9 determined by other regulatory commissions, and that the ORS proposal is
10 significantly lower than those authorized ROEs. This is particularly true with
11 respect to other vertically integrated electric utilities in the Southeastern United
12 States, as Mr. Sullivan notes. To put the Company at a disadvantage vis-à-vis its
13 competitors would be a disservice to customers, and will only cause the cost of
14 capital, particularly equity capital, to rise in the future as rating agencies and
15 equity analysts reconsider whether South Carolina will remain a jurisdiction
16 recognized as one with constructive and credit supportive regulation

17 Q. DOES THE COMPANY DISAGREE WITH OTHER DISALLOWANCE
18 RECOMMENDATIONS MADE BY ORS?

19 A. Yes. Another ORS proposal that the Company would like to address is the ORS's
20 disallowance of the costs to participate in local organizations in the communities
21 that we serve. Organizations like chambers of commerce, economic development
22 associations, and tourism organizations all exist to bring more industry and
23 residents to their region. Duke Energy pays dues to be a part of these

1 organizations because we believe it is important to participate in the communities
2 we serve, and to be engaged at a local level to ensure we understand our
3 customers' needs. This is important in everyday business, but also storm
4 restoration and economic development efforts.

5 For example, our participation in such organizations gets us to the table
6 early for economic development opportunities which benefits our customers and
7 the State. This helps with capacity and reliability discussions, method-of-service
8 decisions, incentive considerations, and more. These discussions and decisions
9 are all important aspects of recruiting prospects, securing deals, and announcing
10 wins for our state. Our contributions to these organizations have a direct link to
11 winning projects for the state of South Carolina. Some notable wins over the past
12 few years include: Toray and Kobelco of Spartanburg County, Giti and Sun Fiber
13 of Chester County, and the Nutramax Labs expansion in Lancaster County. I
14 don't understand why the ORS believes it is inappropriate for the Company to be
15 a good, involved corporate citizen in the communities we serve.

16 **Q. PLEASE DESCRIBE THE COMPANY'S OVERARCHING CONCERNS**
17 **ON EMPLOYEE-RELATED COST DISALLOWANCES PROPOSED BY**
18 **THE ORS.**

19 **A.** I am also concerned about the ORS disallowing compensation costs and normal
20 company costs to reward and engage employees. Our customers are direct
21 beneficiaries of the good work of our employees. No one has argued that our
22 overall salary levels are at issue, rather the ORS proposes to disallow
23 compensation based on how we pay, versus what we pay. As explained by

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1 Witness Metzler, the purpose of carving out a portion of employees' total
2 compensation and delivering it through variable incentive pay is to encourage
3 employees to accomplish objectives intended to ensure safe, reliable, and
4 economical utility service to our customers. This variable incentive pay also
5 ensures that the employees' business units and Duke Energy's overall objectives
6 are met. This not only allows Duke Energy to be competitive in the market, but
7 helps retain the level of talent that the energy industry demands, in order to best
8 serve the customer, safely and efficiently. We also need to keep employees
9 engaged and trained, and Witness Metzler addresses certain recommendations to
10 disallow such costs as well.

11 **Q. PLEASE PROVIDE THE COMPANY'S REACTION TO THE ORS AND**
12 **OTHERS' RECOMMENDATIONS REGARDING THE BASIC FACILITIES**
13 **CHARGE.**

14 **A.** Another area of concern is the various positions from ORS and intervenors on the
15 Basic Facilities Charge. We recognize this is a major issue for many parties, but
16 for us, while we care very much about our customers, this is also an essential
17 element of cost recovery. For every dollar that is not recovered through the Basic
18 Facilities Charge, it has to be recovered through volumetric rates, and that can
19 create cost shifts as well as "spikier" bills in hot summers or cold winters. For
20 example, not having an appropriate Basic Facilities Charge means that other
21 customers are subsidizing low usage customers, such as people with vacation
22 homes or people with second homes elsewhere in the state of South Carolina.
23 Moreover, the Intervenor have not recognized the benefits of the Basic Facilities

1 Charge increase - that it will also reduce volumetric swings, making bills in the
2 summer and winter more tolerable. In other words, the increase in the Basic
3 Facilities Charge also has a smoothing effect on rates that benefits customers.
4 Notwithstanding these aspects of our proposal, we have read the testimony from
5 the other parties and understand that their concerns remain. As noted in Witness
6 Pirro's rebuttal testimony, the Company's cost of service studies, which were
7 accepted by the ORS, indicates that these costs are Customer costs and therefore
8 the Basic Facilities Charge should recover them. If the Commission believes that
9 our proposed increase to the Basic Facilities Charge is too drastic a change at this
10 time, I would point the Commission and parties to Witness Pirro's alternative
11 suggestion of setting the Basic Facilities Charge rate to 50 percent of the
12 difference between the current rate and the cost basis, reducing the proposed
13 Basic Facilities Charge to \$18.15 while shifting the other revenue requirement to
14 the variable component in a manner consistent with that proposed by ORS.

15 **Q. PLEASE PROVIDE THE COMPANY'S REACTION TO THE ORS AND**
16 **OTHERS' RECOMMENDATIONS REGARDING THE COMPANY'S**
17 **GRID IMPROVEMENT PLAN.**

18 **A.** Our grid proposal has brought a lot of Intervenor's to the table. It occurs to me
19 that there are a lot of contradictory points raised by intervenors. On one hand, we
20 have been criticized for not conducting enough stakeholder engagement while on
21 the other hand we have been praised for our engagement. We have been criticized
22 for not following a Certificate of Public Convenience and Necessity ("CPCN")-
23 like process when that is exactly what we have proposed; even though there is no

1 CPCN statute for grid investment in South Carolina. Notwithstanding those
2 criticisms, we have brought these costs to the Commission and parties for a
3 transparent view of what we plan to spend in the next three years alone. We have
4 not asked for overarching approval of our grid improvement plan, but we have
5 filed it for transparency and for a full view of what our costs will be for the next
6 couple of years and we have asked for step up rate increases to recover that
7 investment, as proposed originally by Witness Oliver and further explained in his
8 rebuttal. We believe South Carolina law allows for this and the Commission has
9 done this before in other utility cases, albeit those were settled cases. See Order
10 Number 93-465 in Docket Number 92-619-E; Order Number 2005-83 in Docket
11 Number 2004-259-S; and Order Number 2005-42 in Docket Number 2004-212-S.
12 More importantly, no one has contested the financial effects of not having positive
13 regulatory treatment that were explained by Company Witness Smith in her direct
14 testimony. These are not generating plant investments that rate cases can be built
15 around once they come into service. These are iterative investments that have an
16 immediate negative financial effect on the Company once complete, both from an
17 accounting and financial perspective. No one has contested that point.

18 We believe in our grid plans. As Company Witness Oliver explains, our
19 plans bring real benefits to the state of South Carolina and the longer the process
20 is extended, the more it could stagnate the investment the Company is ready to
21 make into this State and the communities we serve. It could be potentially more
22 expensive as we have to wait to deploy resources that are already lined up to
23 make these improvements for our customers. More importantly, we will delay the

1 benefit that we have clearly articulated through cost-benefit analysis provided
2 within the context of this case. The information that Intervenor say the Company
3 has not provided has been provided. We have provided strong evidence that our
4 plans are reasonable and our spend is reasonable over the next three years. We
5 understand that parties may disagree and we understand that parties may not like
6 what we have proposed, but it is wholly and factually incorrect to suggest that the
7 Company has not substantiated its case.

8 Moreover, even if there was a grid-specific statute along the lines of what
9 the Siting Act requires in South Carolina, those dockets take six months. If we had
10 proceeded under that process it would look exactly the same as what we have
11 proposed in this rate case: filing a request with estimates and explanation of need,
12 proposing the investment, parties' reviewal and the Commission making a
13 decision about the appropriateness of the investment and cost estimates. We
14 believe that we have satisfied the burden, whether it is a rate case burden or a
15 certificate of need-like burden by our proposal in this case. However, if the
16 Commission should decide to open another docket, as suggested by ORS and
17 other parties, it would be of paramount importance that the Commission continue
18 the deferral that it has previously approved to provide continuity—this would
19 serve much like Allowance for Funds Used During Construction does for a
20 generating plant. This is ultimately fair for all involved.

21 We understand this may be one of the most difficult areas in the case. We
22 acknowledge that others prefer we move in a different direction in this area. We
23 believe what we have proposed is the best way, but should the Commission be

1 persuaded by Intervenor to not allow our proposed step ups, at a very minimum
2 the Commission should continue the deferral that is currently in place pursuant to
3 Order No. 2018-751 while the Company continues to answer questions in a
4 subsequent docket and provide more information as we move toward modernizing
5 and improving the grid.

6 **Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

7 **A. Yes.**

1 WITNESS K. SMITH: Good morning, Mr. Chairman,
2 Commissioners.

3 I filed direct, supplemental direct, and
4 rebuttal testimonies in this case. My direct
5 testimony discusses the results of Duke Energy
6 Carolinas' operations under present rates on the
7 basis of an adjusted historical test year using the
8 12-month period ending December 31, 2017, and
9 supports the pro forma adjustments to the test
10 period. My direct testimony also explains the
11 accounting request the company is making regarding
12 deferrals of costs.

13 In addition, my direct testimony discusses the
14 company's request for approval of an Excess
15 Deferred Income Tax – EDIT – rider. My testimony
16 explains the EDIT rider and the five categories of
17 benefits it contains for customers.

18 In my supplemental direct testimony, I present
19 updates to certain accounting and pro forma
20 adjustments and present additional adjustments to
21 the company's cost of service. I also present
22 updates to the company's proposed EDIT rider.

23 In my rebuttal testimony, I address several
24 accounting and ratemaking adjustments proposed by
25 the Office of Regulatory Staff. I address certain

1 accounting adjustments for which we agree with the
2 ORS or do not oppose their adjustments.

3 I also address ORS adjustments that the
4 company opposes. In particular, I oppose the ORS
5 recommendation that the company be disallowed a
6 return on the incremental costs which the company
7 has deferred in a regulatory asset on its books
8 during the deferral period. I also oppose the
9 disallowance proposed by ORS which would deny the
10 company its carrying costs during the amortization
11 period for the Lee nuclear project development
12 costs and for the portion of the other regulatory
13 assets that the ORS has identified as related to
14 operating expenses, as well as unnecessarily long
15 recovery periods for deferred costs recommended by
16 the ORS. If the Commission accepts these proposals,
17 DEC will not be able to fully recover its prudently
18 incurred costs. Debt and equity investors require
19 a return on the cash they have provided to the
20 company, both during the deferral period as well as
21 during the amortization period. To disallow
22 recovery of these costs would be to disallow
23 prudently incurred costs – and no one suggests
24 these costs weren't prudently incurred or that they
25 were not, in fact, incurred.

1 My testimony further explains that the
2 amortization periods recommended by ORS Witness
3 Morgan are unnecessarily long for the deferrals
4 requested for Carolinas West Control Center, Lee
5 combined-cycle and South Carolina AMI. Since the
6 ORS has recommended to disallow the return during
7 the amortization period, the longer amortization
8 periods exacerbate the disallowance. The company
9 opposes these recommendations. The ORS's logic is
10 contradictory, as it does not support a return
11 because the costs were not originally classified as
12 capital, but then the ORS treats them like capital
13 by proposing such lengthy amortization periods.

14 My rebuttal testimony also addresses ORS
15 proposed adjustments not related to deferrals, that
16 the company opposes.

17 The company vigorously opposes the ORS
18 recommendation to disallow certain coal-ash related
19 costs, as explained by Company Witnesses Kerin and
20 Wright in their rebuttal testimony. I also explain
21 in my rebuttal testimony that, although the company
22 does not oppose the ORS recommendation to use an
23 eight-year average expense level for storm
24 restoration costs, we do oppose the ORS removing
25 the inflation impact to storm costs. The company's

1 adjustment is more reasonable, as it adjusts each
2 storm cost year included in the average, to be
3 comparable to the test year on an inflation-
4 adjusted basis, which is appropriate, as costs
5 associated with storm restoration have increased
6 significantly in the last 10 years.

7 The company objects to ORS Witness Gaby
8 Smith's exclusion of annualized test-period O&M
9 non-labor expenses. The requested adjustment is
10 very similar to the customer-growth adjustment
11 which the ORS has accepted. Both adjustments
12 annualize impacts – one for customer growth and one
13 for inflation – and both are appropriate to
14 include. Company Witness Metzler also discusses
15 this, but I provide an overview that Duke Energy
16 Carolinas does not agree with ORS Witness Smith's
17 recommendation to remove 50 percent of DEC's long-
18 and short-term incentive programs' costs.

19 ORS Witness Smith further recommends to
20 disallow certain rate-case expenses due to alleged
21 insufficient documentation to support the costs –
22 specifically, legal services provided by outside
23 counsel and billed via an e-billing system. The
24 ORS has essentially asserted that only a paper
25 invoice will suffice. Duke has utilized an

1 e-billing system for several years, as do many
2 large companies, for administrative efficiency.
3 DEC has offered to provide the ORS additional
4 information, such as affidavits from our vendors,
5 but we have not yet heard back. These expenses
6 were prudently incurred and no justifiable reason
7 for disallowance has been given.

8 The company also requested costs related to
9 its Customer Connect project. ORS Witness Payne
10 recommended removing DEC's proposed increase to O&M
11 as not known and measurable. This is not true, as
12 the costs are based on amounts specified in signed
13 contracts. To allow the company no level of O&M,
14 or solely the amount in the test period, for
15 Customer Connect would be unreasonable. At a
16 minimum, the company's actual O&M of 2018 should be
17 allowed; however, DEC believes its proposed amount
18 is reasonable and should be allowed. Removing the
19 operating expenses needed to implement the project
20 is the same as denying DEC the opportunity to
21 recover those costs for a new billing system which
22 no one has opposed.

23 An alternative that the company would support
24 is for the Commission to approve a continuation of
25 the deferral of the incremental operating expenses

1 incurred related to the Customer Connect project,
2 including a carrying charge on the deferred costs,
3 until the company's next general rate case.

4 In addition to these recommendations, I also
5 oppose ORS Witness Smith's recommendation to remove
6 certain expenses from O&M. Duke Energy Carolinas
7 disagrees with the removal of linemen's rodeo
8 costs, employee incentives, service and safety
9 awards, and any costs to recognize and reward the
10 company's employees who serve our customers. The
11 company further disagrees with the removal of
12 organization dues in support of business, economic
13 development, and the communities we serve.

14 Finally, the company disagrees with the ORS
15 removal of costs shared between North Carolina and
16 South Carolina. The ORS focuses on what costs
17 South Carolina customers should not pay, but
18 ignores the effect of that same logic on what costs
19 South Carolina customers should bear under that
20 same theory.

21 This concludes the summary of my pre-filed
22 testimony.

23 MS. H. SMITH: Thank you.

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[PURSUANT TO PREVIOUS INSTRUCTION, THE
PREFILED DIRECT TESTIMONY OF KIM H.
SMITH FOLLOWS HEREINAFTER]

VOLUME 4
3/21/19

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

**BEFORE
THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA**

DOCKET NO. 2018-319-E

In the Matter of:	)	
	)	DIRECT TESTIMONY OF
Application of Duke Energy Carolinas,	)	KIM H. SMITH
LLC for Adjustments in Electric Rate	)	FOR DUKE ENERGY
Schedules and Tariffs	)	CAROLINAS, LLC

I. INTRODUCTION AND PURPOSE

1 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND**
2 **CURRENT POSITION.**

3 A. My name is Kim H. Smith and my business address is 550 South Tryon
4 Street, Charlotte, North Carolina. I am a Director of Rates and
5 Regulatory, employed by Duke Energy Carolinas, LLC, testifying on
6 behalf of Duke Energy Carolinas ("DE Carolinas" or the "Company").

7 **Q. WHAT ARE YOUR RESPONSIBILITIES IN THIS ROLE?**

8 A. I am responsible for providing regulatory support for retail rates
9 initiatives, including retail rates cases or other significant rates initiatives
10 for DE Carolinas and Duke Energy Progress, LLC ("DE Progress").

11 **Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL**
12 **BACKGROUND AND PROFESSIONAL EXPERIENCE.**

13 A. I graduated from Marshall University with a Bachelor of Science degree in
14 Business Administration, and received a Master of Business
15 Administration degree from the University of Charleston in West Virginia.
16 I am a certified public accountant licensed in the state of North Carolina. I
17 began my career with DE Carolinas in 2006 as an external reporting
18 manager. I joined the Rate Department in 2008 as Rates Manager and was
19 responsible for providing regulatory support for retail and wholesale rates,
20 providing guidance on DE Carolinas and Duke Energy Progress, Inc.'s
21 ("DE Progress") (collectively, the "Utilities") Distributed Energy
22 Resource Program (DERP), Renewable Energy and Energy Efficiency

1 Portfolio Standard ("REPS") compliance and cost recovery applications,
2 energy efficiency cost recovery, and fuel and fuel-related recovery
3 processes. In July 2016, I joined the Regulatory Affairs Department as
4 Regulatory Affairs Manager. I returned to the Rate Department in January
5 2018.

6 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS**
7 **COMMISSION?**

8 A. Yes. I testified before the Public Service Commission of South Carolina
9 ("PSCSC" or "Commission") in DEC's 2016, 2015, 2014 and 2013 fuel
10 and environmental cost recovery proceedings in Docket Nos. 2016-3-E,
11 2015-3-E, 2014-3-E and 2013-3-E, respectively. I also testified in DE
12 Carolinas and DE Progress's 2015 DERP proceedings in Docket Nos.
13 2015-53-E and 2013-55-E.

14 **Q. ARE YOU FAMILIAR WITH THE ACCOUNTING**
15 **PROCEDURES AND BOOKS OF ACCOUNT OF DUKE ENERGY**
16 **PROGRESS?**

17 A. Yes. The books of account of DE Carolinas follow the Uniform System of
18 Accounts prescribed by the Federal Energy Regulatory Commission.

19 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS**
20 **PROCEEDING?**

21 A. The purpose of my testimony is to discuss the results of DE Carolinas'
22 operations under present rates on the basis of an adjusted historical Test
23 Period using the twelve month period ended December 31, 2017 (the "Test

1 Period"). I discuss the additional revenue required as a result of the cost
2 of service based on the pro forma costs in the Test Period. I discuss
3 several pro forma adjustments to the Company's Test Period operating
4 expenses and rate base. I provide the capital structure used in developing
5 the revenue requirements in this case. I also explain the requests the
6 Company is making regarding excess deferred income taxes ("EDIT")
7 rider and cost recovery related to grid improvement investments.

8 **Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?**

9 A. Yes, I have included 3 exhibits. Smith Exhibit 1 sets forth the operating
10 results under current and proposed rates. Smith Exhibit 2 shows the
11 calculation of the proposed EDIT rider to return certain tax change
12 benefits to customers. Smith Exhibit 3 shows the Company's proposed
13 Phase 1 and Phase 2 base rate step-ups related to the Grid Improvement
14 Plan.

15 **Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER**
16 **YOUR DIRECTION AND SUPERVISION?**

17 A. Yes, these exhibits were prepared under my supervision.

18 **II. DETERMINING THE REVENUE REQUIREMENT**

19 **Q. WHAT IS THE REVENUE REQUIREMENT AND HOW DID DE**
20 **CAROLINAS CALCULATE IT?**

21 A. The revenue requirement represents the annual revenues necessary for the
22 Company to recover its operating expenses (including depreciation and
23 taxes) and provide its investors with a fair rate of return on the investment

1 in rate base. DE Carolinas determined its operating costs by identifying
2 depreciation and amortization expense, operations and maintenance
3 ("O&M") expense, fuel expense, taxes, and other expenses charged to
4 utility operations and recorded in its accounting records for the Test
5 Period. The amount of rate base is determined by adding the year-end
6 balances in the Company's accounting records of plant in service,
7 accumulated depreciation, materials and supplies (including fuel
8 inventory) and components of working capital, including certain
9 regulatory assets and liabilities, less deferred taxes and operating reserves.
10 Next, a cost of service study is prepared that allocates and assigns these
11 actual Company operating costs and rate base amounts to determine the
12 per book cost for providing electric service to the Company's South
13 Carolina retail operations. DE Carolinas' Witness Hager discusses in
14 greater detail the allocation process and methodologies used to develop
15 these amounts.

16 Following the cost of service study, the actual Test Period expense
17 and rate base levels, as allocated to the South Carolina retail operations,
18 were adjusted for known and measurable changes, as described below and
19 in the testimony of Witnesses Pirro and McGee. DE Carolinas made
20 certain accounting and pro forma adjustments to actual operating income
21 and rate base for the Test Period to reflect known and measurable changes
22 in order to: (i) normalize for abnormal events; (ii) annualize part year
23 recurring effects to a full year effect; and (iii) show actual changes in

1 costs, revenues or the cost of the Company's property used and useful, or
2 to be used and useful within a reasonable time after the Test Period, in
3 providing service.

4 After the determination of operating expenses and rate base for the
5 Company's South Carolina retail operations, rate base is split between the
6 Company's debt investors and equity investors using the Company's
7 proposed capital structure of 53 percent equity and 47 percent debt. Then,
8 the annual cost of debt is calculated. The income available for the
9 Company's equity investors is determined by subtracting the cost of debt
10 from the operating income produced by the current revenues received
11 from South Carolina retail customers less operating expenses. Finally, the
12 required revenue increase necessary to produce the requested equity return
13 on the amount of the equity invested in rate base is determined.

14 Smith Exhibit 1 sets forth the rate base, operating revenues,
15 operating expenses and operating income the Company earned during the
16 Test Period and the adjusted amounts the Company supports for use in
17 calculating its proposed revenue requirement.

18 **III. RESULTS OF OPERATIONS UNDER EXISTING AND**
19 **PROPOSED RATES**

20 **Q. PLEASE DESCRIBE SMITH EXHIBIT 1 TO YOUR TESTIMONY.**

21 A. Smith Exhibit 1 sets forth the operating results and data required by
22 Commission Reg. 103-823 regarding operating income, calculation of
23 additional revenue requirement, accounting adjustments, and rate base

1 information. The operating results are based on the Test Period noted
2 above, using the twelve months ended December 31, 2017, with
3 appropriate adjustments. This information is also shown on Pages 1
4 through 4d of Exhibit D of the Company's Application.

5 **Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGE 1 OF**
6 **SMITH EXHIBIT 1 ENTITLED "OPERATING INCOME FROM**
7 **ELECTRIC OPERATIONS."**

8 A. Page 1 summarizes the Company's operating income from electric
9 operations for the Test Period both for total Company operations and
10 South Carolina retail operations before the necessary accounting
11 adjustments. It also shows the Company's operating income from electric
12 operations for South Carolina retail operations after the necessary
13 accounting adjustments and the rate of return on South Carolina retail rate
14 base the Company would earn in the Test Period after reflecting those
15 adjustments.

16 Columns 1 and 2 set forth the actual operating revenues, expenses
17 and rate base from the per book cost of service study for the Company and
18 for its South Carolina retail jurisdiction, respectively.

19 Column 3 summarizes the accounting adjustments allocated to
20 South Carolina retail operations necessary to reflect a representative level
21 of operating income and rate base based on known changes in costs. These
22 adjustments are shown on Smith Exhibit 1, Page 3, and are explained later
23 in my testimony and in the testimony of Witnesses Pirro and McGee.

1 Column 4 shows adjusted South Carolina retail operations.

2 Column 5, Line 1 shows the additional revenue requested in this
3 proceeding of \$231 million. The Company is also proposing a rider to
4 decrease revenues by \$63 million for certain tax benefits for a net increase
5 of \$168 million. This is the increase in revenues justified as necessary to
6 cover the Company's cost of service, including a rate of return on
7 members' equity of 10.50 percent as discussed in the testimony of
8 Witnesses Sullivan and Hevert. Column 5 also shows the effect of the
9 revenue increase on general taxes, the Commission regulatory fee, and
10 income taxes.

11 Column 6, Line 13 shows adjusted operating income after the
12 proposed increase in revenues. Column 6, Line 14 shows the adjusted
13 retail rate base. Dividing operating income by rate base produces the 7.74
14 percent overall rate of return that the Company is justifying in this case, as
15 shown in Column 6, Line 15.

16 **Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGE 2 OF**
17 **SMITH EXHIBIT 1 ENTITLED "CALCULATION OF**
18 **ADDITIONAL REVENUE REQUIREMENT."**

19 **A.** Page 2 sets forth the calculation of the additional revenue requirement
20 necessary to produce a 10.50 percent rate of return on members' equity
21 using the format required by Commission Reg. 103-823. To develop this
22 figure, the South Carolina retail rate base was allocated to its capital
23 source components of long-term debt and members' equity. This allocation

1 was based on the capitalization ratios of 47 percent long-term debt and 53
2 percent members' equity, which is the Company's targeted capital
3 structure that this Commission found just and reasonable in its *Order*
4 *Approving Increase in Rates and Charges and Settlement Agreement*,
5 Order No. 2013-661, issued in Docket No. 2013-59-E in DE Carolinas'
6 last general rate case and in its *Order Approving Increase in Rates and*
7 *Charges and Settlement Agreement*, Order No. 2016-871, issued in Docket
8 No. 2016-227-E in DE Progress's last general rate case. Witness Sullivan
9 also comments in his testimony that the 53 percent equity ratio will help
10 the Company enable access to capital at reasonable rates.

11 The amount of operating income needed to cover interest
12 applicable to South Carolina retail rate base was computed using the
13 embedded cost of long-term debt rate, shown in Columns 4 and 7 on Line
14 1. Operating income needed to cover long-term debt interest, shown in
15 Columns 5 and 8 on Line 1, was deducted from total operating income
16 shown in Column 5 on Line 3, to derive operating income remaining for
17 members' equity at present rates as shown in Column 5 on Line 2.

18 Applying the 10.50 percent rate of return on members' equity to
19 that portion of the South Carolina retail rate base financed by members'
20 equity, shown in Column 6, Line 2, produces an operating income
21 requirement for members' equity as shown in Column 8, Line 2.

22 The total operating income requirement shown in Column 8, Line
23 3, is the sum of the requirements for long-term debt and members' equity.

1 Comparing the operating income requirement to the operating income
 2 before the proposed increase in Column 5, Line 3, results in the additional
 3 operating income requirement shown in Column 8, Line 7 after
 4 considering the impact of customer growth. To realize this additional
 5 operating income, the Company must also collect in revenues the increase
 6 in the license fee at a rate of 0.3 percent (\$3 for each \$1,000 of gross
 7 receipts), the public utility assessment fee of 0.14 percent, state income
 8 taxes at a rate of 5 percent, and federal income taxes at a rate of 21
 9 percent. The additional operating income requirement and the additional
 10 taxes and fees produces an additional revenue requirement of \$231million.

11 **Q. HOW IS THIS ADDITIONAL REVENUE REQUIREMENT**
 12 **ALLOCATED AMONG THE CLASSES AND USED TO DEVELOP**
 13 **THE TARGET REVENUE REQUIREMENT FOR RATE DESIGN?**

14 A. Witness Pirro's Exhibit 4 shows how the additional revenue requirement is
 15 spread among the classes and how the target revenue requirements for rate
 16 design are established.

17 **IV. ACCOUNTING AND PRO FORMA ADJUSTMENTS**

18 **Q. PLEASE EXPLAIN PAGE 3 OF SMITH EXHIBIT 1 CAPTIONED**
 19 **"DETAIL OF ACCOUNTING ADJUSTMENTS-SOUTH**
 20 **CAROLINA RETAIL."**

21 A. Page 3 sets forth the individual accounting and pro forma adjustments to
 22 operating revenues and expenses, including the income tax effects for
 23 South Carolina retail electric operations, that were shown in total on Page

1 1 of Smith Exhibit 1 in Column 3. The totals of the columns shown on
 2 Line 36 of Page 3 are the amounts carried forward to Column 3 of Page 1
 3 of Smith Exhibit 1. The impact of the accounting and pro forma
 4 adjustments on rate base are shown on Pages 4 – 4d of Smith Exhibit 1.

5 **Q. PLEASE LIST THESE ACCOUNTING AND PRO FORMA**
 6 **ADJUSTMENTS.**

7 A. The accounting and pro forma adjustments that were made by the
 8 Company are as follows (the chart below indicates which witness is
 9 sponsoring each adjustment):¹

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES (Page 3 of Smith Exhibit 1)		
Line No.	Adjustment Title	Witness
1	Annualize Retail revenues for current rates	Pirro
2	Update fuel costs to approved rate and other fuel related adjustments	McGee
3	Open	
4	Adjust the amount of CWIP in rate base	Smith
5	Eliminate unbilled revenues	Smith
6	Adjust for costs recovered through non-fuel riders	Smith
7	Amortize deferred cost balance related to Carolinas West Control Center	Smith
8	Annualize depreciation on year end plant balances	Smith
9	Annualize property taxes on year end plant balances	Smith
10	Adjust for new depreciation rates and request deferral	Smith
11	Adjust for post test year additions to plant in service	Smith

¹ DE Carolinas intentionally left certain pro forma adjustment line numbers in an "Open" status to keep similar pro forma adjustment line numbers the same between the Company and DE Progress' concurrent rate cases to allow for easy comparison.

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES (Page 3 of Smith Exhibit 1)		
Line No.	Adjustment Title	Witness
12	Reflect 2017 Lee Combined Cycle addition to plant in service	Smith
13	Amortize deferred cost balance related to Lee Combined Cycle	Smith
14	Adjust for Lee Nuclear amortization	Smith
15	Adjust reserve for end of life nuclear costs	Smith
16	Adjust coal inventory	Smith
17	Adjust for approved regulatory assets and liabilities	Smith
18	Amortize deferred environmental costs	Smith
19	Amortize deferred cost balance related to SC AMI	Smith
20	Normalize for storm costs	Smith
21	Annualize O&M non-labor expenses	Smith
22	Normalize O&M labor expenses	Smith
23	Update benefits costs	Smith
24	Levelize nuclear refueling outage costs	Smith
25	Amortize rate case costs	Smith
26	Adjust aviation expenses	Smith
27	Open	
28	Adjust for credit card fees	Smith
29	Adjust O&M for executive compensation	Smith
30	Adjust for Customer Connect Project additional expense and deferral	Smith
31	Adjust vegetation management expenses	Smith
32	Synchronize interest expense with end of period rate base	Smith
33	Adjust 1/8 O&M for accounting and proforma adjustments	Smith
34	Adjust for Federal tax rate change	Smith
35	Adjust deferred cost balance related to SC Grid	Smith

Q. IN CALCULATING THE TOTAL REVENUE REQUIREMENT IN THIS PROCEEDING, DID YOU REVIEW EACH OF THE ACCOUNTING AND PRO FORMA ADJUSTMENTS?

1 A. Yes, I did.

2 Q. IN YOUR OPINION, DO THESE ACCOUNTING AND PRO
3 FORMA ADJUSTMENTS REFLECT KNOWN AND
4 MEASURABLE CHANGES TO THE COMPANY'S TEST PERIOD
5 OPERATING EXPENSES, REVENUES, AND RATE BASE?

6 A. Yes, the adjustments set forth on Page 3 of Smith Exhibit 1, as more fully
7 supported below and in the testimonies of Witnesses McGee and Pirro,
8 reflect known and measurable changes to the Company's Test Period
9 revenues, expenses and rate base. Adjustments that contain projections
10 through December 31, 2018 may be updated with actual results prior to
11 the hearing.

12 Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENTS.

13 A. The following are descriptions of the pro forma adjustments:

14 **1. Annualize retail revenues for current rates**

15 This adjustment annualizes revenue based on the rates in effect at the time
16 of the application, excluding the Distributed Energy Resources Program
17 ("DERP") revenues recovered in the fuel rider, and removes revenues
18 recovered through the Demand Side Management/Energy Efficiency
19 ("DSM/EE") rider. This adjustment to revenues is discussed in more detail
20 in the testimony of Witness Pirro.

1 **2. Update fuel costs to factors approved in Docket No. 2017-3-E**

2 This adjustment adjusts fuel clause expense during the Test Period to
3 match the fuel clause revenues included in Adjustment Line 1. By
4 matching the expenses to the revenue, the adjustment ensures that no
5 increase is requested in this proceeding related to fuel and fuel-related
6 expenses that are recoverable through the fuel clause. However, certain
7 DERP expenses that are not readily identifiable in the general ledger are
8 eliminated by including an offsetting revenue adjustment to keep the
9 DERP incremental cost neutral in this case. This adjustment is described
10 in more detail in Witness McGee's testimony.

11 **3. Open**

12 **4. Adjust the amount of CWIP included in rate base**

13 This adjustment increases rate base to include the balance of construction
14 work in progress ("CWIP") as of December 31, 2018. If these projects are
15 not in service by the time new customer rates in this case are effective, the
16 Company will stop accruing AFUDC on the portion of the projects that is
17 included in rate base starting with the new rates effective date.

18 **5. Eliminate unbilled revenue**

19 This adjustment eliminates unbilled revenue and related taxes recorded by
20 the Company in the test period.

21 **6. Eliminate costs recovered through non-fuel riders**

22 This adjustment removes expense items recovered through the DSM/EE
23 Rider. The revenues and expenses in this rider are reviewed each year in

1 an annual proceeding and should not impact the increase requested in this
2 proceeding.

3 **7. Amortize deferred cost balance related to Carolinas West Control**
4 **Center**

5 In Docket 2018-207-E, the Company petitioned for approval to defer into
6 a regulatory asset account the return and depreciation on the capital costs
7 at its weighted average cost of capital. The Commission approved the
8 Company's petition on August 7, 2018. Witness Oliver discusses the
9 Carolinas West Control Center in more detail. The total projected deferred
10 costs are \$5 million on a South Carolina retail basis. This adjustment
11 amortizes the deferred balance over a 3-year period, resulting in an annual
12 revenue requirement of \$2 million including net of tax return on the
13 unamortized balance of the regulatory asset.

14 **8. Annualize depreciation on year end plant balances**

15 This adjustment reflects the annualization of depreciation expense using
16 the depreciation rates in effect at the end of the test period applied to the
17 end of the Test Period level of plant in service. During the Test Period, the
18 Company recorded depreciation for plant additions from the point in time
19 when they went into service. This adjustment annualizes depreciation
20 expenses to reflect a full year level of depreciation on plant in service as of
21 the end of the Test Period using the depreciation rates that were in effect
22 during the Test Period.

1 **9. Annualize property taxes on year end plant balances**

2 This adjustment annualizes Test Period property taxes on plant in service
3 at December 31, 2017. Property taxes expensed in calendar year 2017
4 were assessed based on property balances at the end of 2016. Likewise,
5 property taxes expensed in the calendar year 2018 will be assessed based
6 on property balances at the end of 2017. This adjustment increases
7 property tax expense in the Test Period to reflect an annual level of
8 expense for property taxes based on the end of the Test Period level of
9 plant investment.

10 **10. Adjust for new depreciation rates and request permission to**
11 **establish a regulatory asset to defer incremental depreciation**
12 **expense**

13 This adjustment adjusts the annualized depreciation expense to reflect the
14 new depreciation rates based on the updated depreciation study prepared
15 by Gannett Fleming and discussed and supported by Witness Doss.
16 Implementing the new depreciation rates will result in an increase to
17 depreciation expense of approximately \$40 million on a system basis, or
18 \$10 million on a South Carolina retail basis. The Company is also
19 requesting permission to establish a regulatory asset to defer the
20 incremental depreciation expense resulting from the new depreciation
21 rates, if and as approved by the Commission. Specifically, the Company
22 seeks to defer approximately \$9 million on a South Carolina retail basis
23 from August 2018 up to the time new rates are in effect. The deferred

1 costs to be recorded on the Company's accounting records will be based
2 on actual costs. This adjustment amortizes the deferred balance over a 3-
3 year period. The increase in depreciation expense and the amortization of
4 the Regulatory Asset results in a revenue requirement of \$13 million.
5 Depreciation allows for the matching of expenses associated with an asset
6 to the revenue that the Company recognizes as a result of utilizing that
7 asset to provide service. Under GAAP, this is referred to as the matching
8 principle and is a fundamental concept in the accounting model. As part
9 of electric utility rate-making, annual depreciation expense is included
10 within the utility's Commission-approved based rates. The incremental
11 annual depreciation expense that the Company seeks to incur as described
12 above is not currently included within the Company's existing base
13 rates. Therefore, it is not possible for the Company to "match" this
14 expense with revenue to be collected. With such a mismatch of expense to
15 revenue, this event is a fundamental departure from the matching
16 principle.

17 **11. Adjust for post test year additions to plant in service**

18 This adjustment increases operating expenses and rate base for significant
19 production, transmission, distribution, general and intangible plant
20 additions the Company has incurred and will incur from the end of the
21 Test Period through December 2018. Witnesses Fallon, Miller, Oliver,
22 Hunsicker and Schneider discuss plant additions in their testimonies.

1 **12. Reflect 2017 Lee Combined Cycle addition to plant in service**

2 This adjustment increases rate base to include electric plant in service
3 amounts for the W.S. Lee Combined Cycle Plant ("Lee CC"). Lee CC is a
4 753-megawatt, natural gas-fired combined cycle plant located in Anderson
5 County, South Carolina. Lee CC was completed and in service in April
6 2018 and replaces older, less efficient coal units that have been retired.
7 The facility is jointly owned by DE Carolinas and North Carolina Electric
8 Membership Cooperative ("NCEMC"). NCEMC's ownership percentage
9 is 12.735 percent. The adjustment includes in rate base the projected
10 electric plant in service balance for the Lee CC project as of December 31,
11 2018, which is \$596 million on a system basis, or \$144 million on a South
12 Carolina retail basis. These amounts reflect DE Carolinas costs net of
13 reimbursement from NCEMC for their ownership share of the facility.
14 This increase to rate base results in an increase to the annual revenue
15 requirement of approximately \$17 million.

16 **13. Amortize deferred cost balance related to Lee Combined Cycle**

17 In Docket 2018-207-E, the Company petitioned for approval to defer into
18 a regulatory asset account costs incurred from the time the facility was
19 placed into service until the time the costs are reflected in the new rates
20 from this proceeding. The costs the Company requested to be deferred are
21 the return and depreciation on the capital costs, the associated incremental
22 non-fuel O&M expenses, property taxes and the carrying cost on the
23 deferred costs at its weighted average cost of capital. The Commission

1 approved the Company's petition on August 7, 2018. The total projected
2 deferred costs are \$22 million on a South Carolina retail basis. This
3 adjustment amortizes the deferred balance over a 3-year period, resulting
4 in an annual revenue requirement of \$8 million, which includes a net of
5 tax return on the unamortized balance of the Regulatory Asset.

6 **14. Adjust for Lee Nuclear amortization**

7 On August 25, 2017, the Company filed a letter with the Commission in
8 SCPSC Docket No. 2011-20-E notifying the Commission that it was
9 requesting approval from the North Carolinas Utilities Commission to
10 cancel the Lee Nuclear Project. Additional information regarding the
11 Company's request for cancellation is reflected in Witness Fallon's direct
12 testimony. As a result of the cancellation of the project, the Company
13 requests permission to establish a Regulatory Asset consisting of the
14 balance of Lee nuclear development costs, adjusted to remove non-
15 depreciable land costs and estimated expenditures through May 31, 2019.
16 The total system estimated balance of cost at May 31, 2019 is \$559
17 million, which includes non-depreciable land costs of \$41 million. The
18 proforma moves the non-depreciable land costs to Plant Held for Future
19 Use. The total balance for which the Company is requesting recovery
20 from South Carolina retail customers is \$125 million. The annual revenue
21 requirement requested in this proceeding is \$20 million, comprised of
22 annual amortization expense, over 12 years, of \$11 million, and a net of

1. tax return of \$9 million on the unamortized balance of the Regulatory
2. Asset and plant held for future use.

3 **15. Adjust reserve for end of life nuclear costs**

4 This adjustment adjusts depreciation and amortization expenses in order to
5 establish a reserve for end of life nuclear costs. There are some end-of-life
6 costs at a nuclear plant that are not captured in a decommissioning study.
7 One example of this is the expense to write off the materials and supplies
8 in inventory at the time of decommissioning that have little or no salvage
9 value. The Company is proposing to create a reserve to start accruing for
10 these end-of-life expenses for obsolete materials and supplies and,
11 therefore, create a better matching of cost and benefit for ratemaking
12 purposes. The annual accrual amount will be determined by dividing the
13 projected inventory balance at the end of each unit's life by the number of
14 years remaining in the unit's life and summing this result for the
15 Company's three nuclear plants. In this proceeding, the Company is
16 requesting an annual accrual amount of approximately \$5 million as
17 allocated to South Carolina retail. The annual accrual amount can be
18 reviewed and adjusted, if needed, in each future general rate case before
19 the end of the plant's life. The reserve, once it is created, will be included
20 as an offset to rate base in the cost of service, and the pro forma decreases
21 rate base to reflect one year's worth of the accrual.

22 The Company is also proposing to create a reserve to start accruing for the
23 expense related to a portion of the last core of nuclear fuel in the reactor at

1 the end-of-life of its generating plants and, therefore, create a better
2 matching of cost and benefit for ratemaking purposes. The annual accrual
3 amount will be determined by dividing the projected remaining value of
4 the last core of nuclear fuel at the end of each unit's life by the number of
5 years remaining in the unit's life and summing this result for the
6 Company's three nuclear plants. In this proceeding, the Company is
7 requesting an annual accrual amount of \$2 million as allocated to South
8 Carolina retail. The annual accrual amount can be reviewed and adjusted,
9 if needed, in each future general rate case before the end of the plant's life.
10 The reserve, once it is created, will be included as an offset to rate base in
11 cost of service and the pro forma decreases rate base to reflect one year's
12 worth of the accrual.

13 **16. Adjust coal inventory**

14 This adjustment increases the Company's actual coal inventory at the end
15 of the Test Period to reflect a targeted 40-day full load burn for each of the
16 coal generating plants. This change in coal inventory for the South
17 Carolina retail jurisdiction is shown on Smith Exhibit 1, Page 4c, Line 3,
18 Column 3.

19 **17. Adjust for approved regulatory assets and liabilities**

20 This adjustment removes from Test Period costs the amortization of
21 various regulatory assets or liabilities that have been approved by the
22 Commission in previous general rate case proceedings. The amortization
23 period for items removed will expire before proposed new rates are

1 effective, and thus should not be included in Test Period expenses on
2 which rates are based.

3 **18. Amortize deferred environmental costs**

4 On June 8, 2016, the Commission granted DEC's petition in Docket No.
5 2016-196-E for authority to defer in a regulatory asset account certain
6 costs incurred in connection with compliance with federal and state
7 environmental requirements as it relates to Coal Combustion Residuals
8 ("CCR" or "coal ash"). The nature of these costs is described in more
9 detail in Witness Kerin's testimony. No fines, penalties, or costs on which
10 DE Carolinas has agreed to forego recovery are included in the deferral.
11 The Company also proposed to offset the South Carolina Ash Basin
12 Closure Costs with the excess decommissioning regulatory liabilities as
13 provided in the decommissioning orders. While the costs to comply with
14 CAMA and the CCR Rule are largely duplicative, there are a small portion
15 of the costs that the Company has determined are specific to CAMA,
16 unique to North Carolina and appropriate for direct assignment to North
17 Carolina, as discussed by Witness Kerin. In the deferral calculation,
18 CAMA-specific costs are excluded for SC retail. Some of the deferred
19 compliance costs are related to ash basin closure and are subject to asset
20 retirement obligation ("ARO") accounting per Generally Accepted
21 Accounting Principles ("GAAP"). Some of the deferred compliance costs
22 are related to the continued operation of the active plants and are not
23 subject to ARO accounting, and instead are capitalized to plant in service.

1 The compliance costs included in this case are based on actuals from
2 January 1, 2015 through September 30, 2018, plus a projection, as of the
3 time of filing, from October 1, 2018 through December 31, 2018. The total
4 system spend on ash basin closure costs subject to ARO accounting during
5 this period (January 2015 through December 2018) for DE Carolinas is
6 \$958 million. After removing CAMA-specific costs, applying allocations
7 factors, adjusting for the excess decommissioning regulatory liabilities and
8 incorporating the return on the deferred costs, the expected deferred
9 balance as of May 31, 2019, on a South Carolina retail basis is \$231
10 million. The total system compliance amounts placed in service related to
11 continued operations at active plants during the year 2018 were \$528
12 million. The deferred depreciation and return on these investments results
13 in an additional deferred balance on a South Carolina retail basis of \$11
14 million, for a total deferred balance of \$242 million. The Company
15 proposes to amortize the combined Regulatory Asset of \$242 million over
16 5 years. The annual amortization expense is \$48 million. When added
17 together with the net of tax return on the unamortized balance of \$14
18 million, the total revenue requirement requested in this case for deferred
19 coal ash related compliance costs is \$62 million. The Company expects to
20 continue to invest significant amounts related to coal ash compliance after
21 the December 2018 cut-off in this case. Instead of requesting recovery of
22 an ongoing level of these costs in this case, the Company is requesting the
23 Commission approve a continuation of the deferral, similar to what it

1 approved in Docket 2016-196-E, for costs not included in this case.
2 Specifically, the Company is requesting approval to defer CCR
3 compliance spend related to ash basin closure beginning January 1, 2019,
4 the depreciation and return on CCR compliance investments related to
5 continued plant operations placed in service on or after January 1, 2019,
6 and a return on both deferred balances at the overall rate of return
7 approved in this case.

8 **19. Amortize deferred cost balance related to SC AMI**

9 In Docket 2016-240-E, the Company petitioned for approval to defer into
10 a regulatory asset account the incremental operating and maintenance
11 expense and the depreciation expense incurred once the Advanced
12 Metering Infrastructure technology (AMI) meters are installed, as well as
13 the associated carrying costs on the investment and deferred costs at its
14 weighted average cost of capital. The Commission approved the
15 Company's petition on June 29, 2016. Witness Schneider discusses these
16 costs in more detail. The total projected deferred costs are \$38 million on
17 a South Carolina retail basis. This adjustment amortizes the deferred
18 balance over a 3-year period, resulting in an annual revenue requirement
19 of \$15 million, including net of tax return on the unamortized balance of
20 the regulatory asset.

1 **20. Normalize for storm costs**

2 This pro forma adjustment normalizes storm restoration costs to an
3 average level of costs the Company has experienced over the last ten
4 years. This adjustment increases Test Period costs to the 10- year average
5 South Carolina retail cost of \$7 million.

6 **21. Annualize O&M non-labor expenses**

7 This adjustment annualizes Test Period O&M expenses excluding fuel,
8 purchased power, and labor costs to reflect the change in unit costs that
9 occurred during this period.

10 **22. Normalize O&M labor expenses**

11 This adjustment adjusts the wages and salaries, related employee benefit
12 costs to reflect annual levels of costs as of July 1, 2018. This adjustment
13 also reflects changes in related payroll taxes.

14 **23. Update benefits costs**

15 This adjustment updates the Test Period cost of labor-related benefits to
16 match the result of an updated study performed by the Company's
17 consultants.

18 **24. Levelize nuclear refueling outage costs**

19 In the Company's last general rate case, the Commission approved an
20 accounting mechanism that levelized certain costs related to nuclear
21 refueling outages. This adjustment annualizes the amortization expense
22 related to this mechanism incurred during the Test Period to the level
23 experienced at the end of the Test Period.

1 **25. Amortize rate case costs**

2 This adjustment amortizes the incremental rate case costs incurred for this
3 docket over a 5-year period.

4 **26. Adjust aviation expenses**

5 This adjustment removes 50 percent of the corporate related aviation
6 expenses allocated to DE Carolinas in the Test Period that are not related
7 to aerial patrol. While the Company believes these costs are reasonable,
8 prudent and appropriate to recover from customers, we have for purposes
9 of this case made an adjustment to this item.

10 **27. OPEN**

11 **28. Adjust for credit card fees**

12 Currently, customers who pay their electric bill by credit card, debit card
13 or ACH are required to pay a fee of \$1.50 per transaction to the third party
14 who processes these payments. As described in the testimony of Witness
15 Ghartey-Tagoe, the Company is now proposing to implement a fee-free
16 credit/debit card program that would allow residential customers to utilize
17 their credit cards or debit cards to pay their utility bills without paying a
18 surcharge or convenience fee, and instead for the Company to pay these
19 costs to the third party and recover the cost from all customers as part of
20 its cost of service. This adjustment increases operating and maintenance
21 expense by \$3 million to reflect this cost including the growth in number
22 of transactions expected as a result of this change.

1 **29. Adjust O&M for executive compensation**

2 This adjustment removes 50 percent of the compensation of the four Duke
3 Energy executives with the highest level of compensation allocated to DE
4 Carolinas in the test period. While the Company believes these costs are
5 reasonable, prudent and appropriate to recover from customers, we have
6 for the purposes of this case made an adjustment to this item.

7 **30. Adjust for Customer Connect project**

8 The Customer Connect project will replace the Company's current billing
9 system and is currently planned to be placed in service in 2022. The
10 project is described in more detail in the testimony of Witness Hunsicker.
11 Due to the nature of the project costs, a significant amount of the spending
12 between now and the in-service date will be O&M. This adjustment
13 increases the Test Period O&M by \$4 million (from \$0.7 million to \$4.7
14 million), which is the average incremental level on a South Carolina retail
15 basis expected over the next two years. These estimates are based on
16 signed contracts for the primary software, systems integration and change
17 management professional services, that resulted from an extensive request
18 for proposal process conducted in 2016. This adjustment also requests
19 recovery of deferred expenses from January 1, 2018 until the time the
20 costs are reflected in the new rates from this proceeding. In Docket 2018-
21 207-E, the Company petitioned for approval to defer into a regulatory
22 asset account the incremental operating and maintenance expenses
23 associated with the deployment of the Customer Connect project and

1 carrying costs on the deferred costs at its weighted average cost of capital
2 incurred since January 1, 2018 until mid-2019. This request was approved
3 by the Commission on August 7, 2018. The total estimated deferred costs
4 at May 31, 2019 are expected to be \$5 million. The Company is seeking
5 recovery of the deferred costs over a three-year period including a net of
6 tax return on the unamortized balance of the regulatory asset resulting in a
7 revenue requirement of \$2 million. The increase in O&M of \$4 million
8 plus the annual revenue requirement related to the recovery of the deferred
9 costs of \$2 million equal a combined revenue increase for this adjustment
10 of \$6 million.

11 **31. Adjust vegetation management expenses**

12 This adjustment increases operating and maintenance expense in the Test
13 Year to reflect enhancements to the Company's on-going vegetation
14 management program. Witness Oliver discusses the Company's
15 vegetation program in more detail.

16 **32. Synchronize interest expense with end of period rate base**

17 This adjustment adjusts income taxes for the tax effect of the annualization
18 of interest expense reflected in the pro forma cost of service.

19 **33. Adjust 1/8 O&M for accounting and pro forma adjustments**

20 This adjustment adjusts the Company's rate base to include the additional
21 working capital required as a result of the additional O&M expenses the
22 Company is proposing in this proceeding as shown on Line 2, Column 3
23 of Smith Exhibit 1, Page 4d.

1 **34. Adjust for Federal tax change**

2 Witness Panizza discusses the Tax Cuts and Jobs Act (the "Tax Act"),
3 which became law on December 22, 2017. One change he discusses from
4 the Tax Act is the reduction in the corporate income tax rate from 35 to 21
5 percent. This adjustment reduces the test period income tax expense to
6 reflect this change. The adjustment also reduces accumulated deferred
7 income taxes for one year's worth of the deferred income tax expense
8 adjustment. The net result of this adjustment is a reduction in revenue
9 requirement for customers of \$66 million. In addition to impacting tax
10 expense, the reduction in the corporate income tax rate also impacts the
11 levelized amortizations established in the last rate case (Lines 21 and 27 of
12 Settlement Agreement Attachment A). Because the tax rate is now lower,
13 the after-tax rate of return is higher, which would result in an increase in
14 the levelized amortization expense. Instead of proposing to increase the
15 amortization expense in this case, the Company is proposing to keep the
16 amortization expense equal to the amount established in the last rate case.
17 This will result in a longer amortization period than was anticipated in that
18 case. Other impacts of the Tax Act and benefits for customers are
19 described later in my testimony.

20 **35. Grid Improvement Plan Deferral**

21 In Docket 2018-206-E, the Company requested and the Commission
22 approved deferral of costs related to the Company's Grid Improvement
23 Plan. In 2018, the Company has, or will by December, place in service

1 investments of \$44 million on a South Carolina retail basis. The deferral
2 of the depreciation, O&M, property tax, and return on these investments
3 plus the return on deferred balance, results in a deferred balance as of May
4 31, 2019, of \$7 million. This adjustment amortizes this deferred balance
5 over a two-year period for a revenue requirement impact of \$4 million for
6 this adjustment. I discuss the proposed recovery for investments under the
7 Grid Improvement Plan placed in service after December 2018 later in my
8 testimony.

9 **Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGES 4**
10 **THROUGH 4d OF SMITH EXHIBIT 1.**

11 **A.** Page 4 shows total Company and South Carolina retail components of
12 original cost rate base. The total Company amounts and South Carolina
13 retail components were taken from the Company's Cost of Service Study
14 as of December 31, 2017.

15 Pages 4a, 4b, 4c, and 4d are details of components making up
16 original cost rate base as of December 31, 2017 adjusted for known and
17 measurable changes. On each of these four pages, Column 1 shows the
18 total Company per book amounts at December 31, 2017; Column 2
19 reflects the amount for South Carolina retail electric operations; Column 3
20 sets forth the accounting adjustments allocated to South Carolina retail
21 operations; and Column 4 reflects the South Carolina retail amounts
22 including adjustments.

Page 4a is a summary of the Company's investment in electric plant in service as of December 31, 2017 by functional classification. Page 4b details accumulated depreciation and amortization for each of the classes of electric plant in service. The composite depreciation rates based on end of 2017 plant balances for each class of property are shown at the bottom of the page on Lines 8 through 15. The depreciation rates underlying these composite calculations are supported by Witness Doss. Page 4c is a summary of the Company's investment in materials and supplies as of December 31, 2017 included in rate base. Page 4d reflects the working capital investment included in rate base.

V. EXCESS DEFERRED INCOME TAX ("EDIT") RIDER

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED EDIT RIDER.

A. Witness Panizza discusses the Tax Act, which became law on December 22, 2017. Earlier in my testimony, I described how the Company has incorporated into the base rate revenue requirements in this case the reduction in the corporate income tax rate from 35 to 21 percent. For the remaining benefits of the Tax Act, the Company is proposing to create an EDIT rider. Smith Exhibit 2 shows the Year 1 calculation of this rider, and then shows for illustrative purposes how the rider would be calculated in future years. The rider contains the following five categories of benefits for customers:

1. Federal EDIT - Protected
2. Federal EDIT - Unprotected, PP&E related

1 3. Federal EDIT – Unprotected, non PP&E related

2 4. Deferred Revenue

3 5. NC EDIT

4 Federal EDIT – Protected, Unprotected PP&E related, and Unprotected,
5 non PP&E related

6 At the end of 2017, the company had a certain amount of Accumulated
7 Deferred Income Taxes (“ADIT”) on its balance sheet. These are income
8 taxes which the Company has expensed for accounting purposes, but for
9 which the Company will not need to pay the IRS until some point in the
10 future. Because the Company has use of the cash until it has to pay the
11 IRS, the ADIT is included as a reduction to rate base and is basically used
12 as a source of financing for investments used to benefit customers – poles,
13 lines, generation plant investments, etc. With the change in the federal tax
14 rate, the amount that the Company must pay to the IRS in the future for
15 these ADIT obligations has been reduced. At the end of 2017, the
16 Company calculated this reduction and the difference was carved out and
17 stayed on the balance sheet, and in rate base, as EDIT. Instead of having
18 an obligation to pay this money to the IRS in the future, the Company now
19 has an obligation to pay it to customers. However, since the money is
20 currently being used to finance investments benefitting customers, as the
21 Company pays the money to customers, it must find other sources of
22 financing for these investments. If the money is returned to customers too

1 quickly, it can put pressure on the Company's credit metrics and create
2 rate volatility for customers. Within EDIT, there are three subcategories.

3 ▪ Protected – These amounts are generally related to Property, Plant
4 & Equipment (PP&E) and there are specific IRS requirements that
5 require that this amount be returned to customers no more quickly
6 than the prescribed method. The amortization period the Company
7 is using here is called the Average Rate Assumption Method
8 ("ARAM") and results in a Year 1 amortization rate for this
9 category of 3.10 percent. Also, because under this method, the
10 Company would have been allowed to return a certain amount of
11 this category to customers in 2018, but did not, the Company
12 calculated the amount that could have been returned and moved it
13 into the Unprotected, non-PP&E related category. This is shown
14 on Line 2 of Smith Exhibit 2 Page 1.

15 ▪ Unprotected PP&E related – These amounts are also related to
16 PP&E but do not fall under the federal guidelines for protected
17 status. Because the Company would have paid these amounts to
18 the IRS over the remaining life of the underlying property, the
19 Company is proposing to return these amounts to customers over a
20 20-year period.

21 ▪ Unprotected non PP&E related – These amounts are not related to
22 property and instead are related to items such as regulatory assets
23 and liabilities, and other balance sheet items, and also include the

1 amount transferred from the Protected category. The Company is
2 proposing to return these amounts to customers over a 5-year
3 period.

4 Deferred Revenue

5 As directed in Docket 2017-381-A, the Company began deferring
6 effective January 1, 2018, the impact on customer rates of the reduction in
7 the federal corporate income tax rate. Line 4 of Smith Exhibit 2, Page 1,
8 shows the projected balance for this liability as of December 2018. The
9 Company will continue to defer the impact from January 1, 2019 through
10 the new rates effective date in this case. Those additional amounts are not
11 known at this time, and will be included in the Year 2 EDIT rider
12 calculation. The Company has also netted against the projected balance
13 the deferred balances related to the Distributed Energy Resource Program
14 ("DERP"). This offset is discussed further by Witness Gharthey-Tagoe.

15 NC EDIT

16 ▪ Similar to the EDIT that results from the reduction in the federal
17 corporate income tax rate, there are EDIT balances that resulted
18 from the reduction in the North Carolina state corporate tax rate.
19 The Company is proposing to return these amounts to customers
20 over a 5-year period.

1 **Q. PLEASE EXPLAIN HOW THESE FIVE CATEGORIES OF**
2 **BENEFITS WILL BE INCORPORATED INTO THE EDIT RIDER.**

3 A. The proposed rider will contain the amortization for each of these five
4 categories of benefits. These amounts can be seen in Columns B through
5 G of Smith Exhibit 2 Page 2. As these amounts are refunded to customers,
6 rate base will increase. As such, the rider also calculates the return on the
7 increased rate base since the last rate case. This is shown in Column L
8 Smith Exhibit 2 Page 2. Column M shows the sum of the amortization
9 and return, and Column N shows the revenue requirement for the rider
10 grossed up for license fee and the public utility assessment fee. The
11 amount in the Year 1 row on Smith Exhibit 2 Page 2 of \$63 million
12 decrease is the rider that is being proposed in this case. Some of the
13 balances used to create the Year 1 rider are as of the end of 2017 or
14 projected end of 2018 balances. I will provide an updated version of this
15 exhibit with end of 2018 actual balances prior to the hearing. I will also
16 update the exhibit with whatever the latest known ARAM rate is at that
17 time to avoid possible normalization violations. Years 2 through 5 are
18 shown for illustrative purposes. However, the actual rider amounts for
19 those years may change based on several factors.

20 First, if there are additional adjustments to any of the balances on
21 Rows 1 through 5 of the exhibit, the annual amortization amounts will be
22 recalculated to accommodate the change in balance. For example, the
23 Company has included the projected deferred revenue through December

1 2018 in the Year 1 rider. The Company will continue to defer revenue for
2 the change in the federal income tax rate until new rates effective in this
3 case reflect the change. This additional deferred balance is unknown at
4 this time, but will be incorporated into the rider in subsequent years.

5 A second factor that would impact the calculation of the rider
6 beyond Year 1 is changes in the ARAM rate. The Company updates this
7 rate annually and the most current rate must be used when establishing
8 customer rates.

9 A third factor that would impact the calculation of the rider beyond
10 Year 1 is the impact of future rate cases. In future rate cases, the EDIT
11 balance in base rates shown in Column J and the rate of return used to
12 calculate Column L of Smith Exhibit 2, Page 2 would be updated based on
13 what is approved in that case.

14 Finally, the retention factor used to calculate Column N will be
15 updated to reflect any future changes in the license fee or public utility
16 assessment fee rates as needed.

17 The Company proposes to file the rider amounts, along with the
18 spread to the classes and derivation of the rate, for each subsequent year
19 with the Commission in this docket by March 31, for rider rates effective
20 June 1.

21 The year one EDIT revenue requirement, shown in Smith Exhibit
22 2, was provided to Witness Pirro who explains the derivation of the rider

1 rate in his testimony. Witness Hager explains how the amounts were
2 allocated to the customer classes in her testimony.

3 **VI. GRID IMPROVEMENT PLAN REQUEST**

4 **Q. HAS THE COMPANY INCLUDED COSTS ASSOCIATED WITH**
5 **THE GRID IMPROVEMENT PLAN?**

6 A. Yes. The Company has included grid improvement investments, placed in
7 service through December 31, 2018, in the revenue requirement
8 calculation shown in Smith Exhibit 1. The revenue requirement on these
9 investments are included in Line 11, Adjust for post test year additions to
10 plant in service, and Line 35, Amortize deferred cost balance related to SC
11 Grid, of my pro forma adjustments shown on Smith Exhibit 1, Page 3, and
12 described earlier in my testimony.

13 **Q. HAS THE COMPANY SOUGHT ANY ADDITIONAL**
14 **ACCOUNTING AND RECOVERY METHODS FOR ONGOING**
15 **GRID IMPROVEMENT PLAN COSTS?**

16 A. Yes. The Company's application requests that the Commission approve
17 the Company's Grid Improvement Plan as described by Witness Oliver,
18 along with associated Phase 1 and Phase 2 rates effective June 1, 2020 and
19 June 1, 2021. Such Phase 1 and Phase 2 proposed rates, provided in Pirro
20 Direct Exhibit 7, serve as "step-ups" in base rates for the revenue
21 requirement associated with those investments to be approved in this case.
22 Smith Exhibit 3 shows the calculation of the proposed Phase 1 and Phase
23 2 revenue requirements in more detail. For investments under the plan

1 placed in service from January 1, 2019 through December 31, 2019, the
2 company is proposing to capture the costs associated with these
3 investments in the Phase 1 rates, effective one year after the rates effective
4 date requested in this case, June 1, 2020. For investments under the plan
5 placed in service from January 1, 2020 through December 31, 2020, the
6 Company is proposing to capture the costs associated with these
7 investments in the Phase 2 rates, effective one year after the Phase 1 rates
8 on, June 1, 2021. As part of this request, the Company seeks approval to
9 defer costs associated with the incremental grid investments placed in
10 service after December 31, 2018, until those costs are included in base
11 rates, either through the Phase 1 or 2 rates or a subsequent general rate
12 case. The Phase 1 rates would also include amortization of deferred costs
13 associated with 2019 investments over a two-year period. The Phase 2
14 rates would include amortization of deferred costs associated with 2020
15 investments over a two-year period, and would also include a decrement to
16 remove what will then be the completed amortization for 2018
17 investments described in pro forma Line 35.

18 As to the deferral of cost incurred between rate effective dates, the
19 Company respectfully requests Commission approval to defer the financial
20 effects of the grid improvement work outlined by Witness Oliver,
21 including incremental O&M, depreciation expense and property tax, as
22 well as the carrying costs on the investment and on the deferred costs at
23 each utility's weighted average cost of capital, until the rates effective date

1 of the Phase 1 and 2 rates, effective June 1, 2020 and June 1, 2021,
2 respectively, and then afterward until the utility's next general rate case.

3 **Q. PLEASE EXPLAIN WHAT IS SHOWN IN SMITH EXHIBIT 3.**

4 A. Page 1 of Smith Exhibit 3 shows the revenue requirement for both the
5 South Carolina retail jurisdiction and by rate class for Phase 1 and Phase 2
6 on Lines 21 and 31, respectively. The revenue requirement increase in
7 total for South Carolina retail is \$16 million for Phase 1 and \$20 million
8 for Phase 2.

9 Page 2 shows the derivation of the Phase 1 jurisdictional revenue
10 requirement including the amortization of the deferred balance for 2019
11 investments.

12 Page 3 shows the details of the deferral calculation for the 2019
13 investments, including the plant in service, O&M and amortization
14 amounts that carry forward to Page 2.

15 Page 4 shows the derivation of the Phase 2 jurisdictional revenue
16 requirement including the amortization of the deferred balance for 2020
17 investments.

18 Page 5 shows the details of the deferral calculation for the 2020
19 investments, including the plant in service, O&M and amortization
20 amounts that carry forward to Page 4.

21 Page 6 shows the system capital spend and O&M for 2019 and 2020 that
22 corresponds to the Grid Improvement Plan described by Witness Oliver.

23 It also shows the allocations to South Carolina retail and the assumptions

1 for the lag between when capital is spent and when assets are placed in
2 service that was used for the revenue requirement calculation. The
3 numbers and assumptions on this page are the basis for the detailed
4 deferral calculations on Pages 3 and 5.

5 Page 7 shows the cost of capital requested in this case and used in the
6 calculation of the revenue requirements on Pages 2 through 5.

7 **Q. WOULD THE PARTIES HAVE A CHANCE TO REVIEW THE**
8 **WORK COMPLETED IN ADVANCE OF THE EFFECTIVE DATE**
9 **OF NEW RATES?**

10 A. Yes. The Company would be willing to file status reports to apprise
11 stakeholders of the progress as explained by Witness Oliver, as well as
12 through an ORS conducted audit.

13 **Q. IF APPROVED, WOULD THE COMPANY AGREE TO PUT**
14 **FORTH THE SAME INFORMATION FOR FUTURE YEARS?**

15 A. Yes. The Company envisions that the expenditures for years outside of
16 the Grid Improvement Plan (not established in this case) be brought back
17 before the Commission through a process like this one for similar
18 treatment.

1 **Q. PLEASE DESCRIBE THE ORS AUDIT REFERENCED ABOVE?**

2 **A.** We propose that the audit by ORS be conducted prior to the effective date
3 of the Phase 1 and 2 rates to be approved in this case. Accordingly, we
4 recommend the following parameters for an audit:

- 5 ▪ By March 1 of 2020 and 2021, the Company will file an updated
6 version of Smith Exhibit 3 showing the actual grid improvement
7 plan balances placed in service and incremental O&M by month
8 during the prior calendar year. The Company will certify that
9 these plant in service and O&M amounts are part of the Grid
10 Improvement Plan described by Witness Oliver, and are ready to
11 be audited. The Company will also include a narrative explaining
12 the work completed and the status of the plan.
- 13 ▪ The ORS should audit the plant in service balances and confirm
14 whether the Company has indeed placed in service the amounts
15 included in the updated Smith Exhibit 3 and spent the incremental
16 O&M and that these were investments under the Commission-
17 approved Grid Improvement Plan. The audit should be limited in
18 scope and not a recreation of the rate case (return on equity, cost
19 allocation, etc.) or an examination of the appropriateness of the
20 Grid Improvement Plan.
- 21 ▪ ORS should be given sixty (60) days from the date that the
22 Company files the updated Smith Exhibit 3 to complete its audit
23 and file a report with the Commission on May 1.
- 24 ▪ When ORS certifies to the Commission by May 1 that the
25 Company has met the conditions above, the Phase 1 and 2 rates
26 should be placed into effect for service on or after June 1.

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31 **Q. WHAT HAPPENS IF THE ACTUAL INVESTMENTS RESULT IN**
32 **A REVENUE REQUIREMENT LESS THAN THE AMOUNT**
33 **SHOWN IN SMITH EXHIBIT 3?**

34 **A.** With its March 1, 2020 and March 1, 2021 certifications, the Company
35 will include an updated version of Smith Exhibit 3 with the actual
36 investments placed in service in the prior calendar year. If the update

1 results in a lower revenue requirement, the approved step-up rates will be
2 reduced to reflect the lower revenue requirement. If the update results in a
3 higher revenue requirement, the approved step-up rates will not change,
4 and the difference will be deferred to be considered in a future general rate
5 case. As a result, the Phase 1 and Phase 2 rate changes will be no greater
6 than the amounts approved in this case; however, they could be less.

7 **VII. CONCLUSION**

8 **Q. IN YOUR VIEW, ARE THE OPERATING EXPENSES AND RATE**
9 **BASE CALCULATED BY DE CAROLINAS IN THIS**
10 **PROCEEDING IN ACCORDANCE WITH THE PROVISIONS OF**
11 **S.C. CODE ANN. SECTIONS 58-27-820 AND 58-27-870 AND 26 S.C.**
12 **CODE REGS. 103-303 AND 103-823?**

13 **A.** Yes, they are. The Company generally experienced a level of ordinary
14 business expenses and rate base that was reasonable and necessary to
15 provide safe and reliable electric service to its customers for the twelve-
16 month period ended December 31, 2017. In order to meet the
17 requirements of S.C. Code Ann. Sections 58-27-820 and 58-27-870 and 26
18 S.C. Code Regs. 103-103 and 103-823, the actual operating expenses and
19 rate base levels for the Test Period were adjusted for known and
20 measurable changes as described above.

1 Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT
2 TESTIMONY?
3 A. Yes.

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[PURSUANT TO PREVIOUS INSTRUCTION, THE
PREFILED SUPPLEMENTAL DIRECT TESTIMONY OF
KIM H. SMITH FOLLOWS HEREINAFTER]

VOLUME 4
3/21/19

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

**BEFORE
THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA**

DOCKET NO. 2018-319-E

In the Matter of:	)	
	)	SUPPLEMENTAL DIRECT
Application of Duke Energy Carolinas,	)	KIM H. SMITH
LLC for Adjustments in Electric Rate	)	FOR DUKE ENERGY
Schedules and Tariffs	)	CAROLINAS, LLC

I. INTRODUCTION AND PURPOSE

1 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND**
2 **CURRENT POSITION.**

3 **A.** My name is Kim H. Smith and my business address is 550 South Tryon
4 Street, Charlotte, North Carolina. I am a Director of Rates and
5 Regulatory, employed by Duke Energy Carolinas, LLC, testifying on
6 behalf of Duke Energy Carolinas ("DE Carolinas" or the "Company").

7 **Q. ARE YOU THE SAME KIM H. SMITH WHOSE DIRECT**
8 **TESTIMONY AND EXHIBITS WERE FILED IN THIS DOCKET**
9 **ON NOVEMBER 8, 2018?**

10 **A.** Yes.

11 **Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT**
12 **TESTIMONY IN THIS PROCEEDING?**

13 **A.** The purpose of my supplemental direct testimony is to present updates to
14 certain accounting and pro forma adjustments and present additional
15 adjustments to the Company's cost of service as shown on Smith
16 Supplemental Exhibit 1. As I stated on page 13 of my direct testimony,
17 several adjustments included in the Company's original filing contained
18 projections that the Company reserved the right to update with actuals
19 prior to the hearing. In my supplemental direct testimony, I update those
20 adjustments to reflect actuals. I also update or present adjustments based
21 on circumstances and events that have occurred since the Company made
22 its November 8, 2018 filing. Finally, I present updates to the Company's

1 proposed Excess Deferred Income Tax ("EDIT") rider as shown in
2 Updated Smith Exhibit 2.

II. UPDATES TO THE COMPANY'S TEST YEAR
OPERATING REVENUE, EXPENSES AND RATE BASE

3
4 **Q. PLEASE DESCRIBE SMITH SUPPLEMENTAL EXHIBIT 1.**

5 A. Smith Supplemental Exhibit 1 presents the illustrative impact of additional
6 adjustments to the Company's cost of service. While DE Carolinas is not
7 requesting a change in its proposed revenue requirement as a result of
8 these adjustments at this time, Smith Supplemental Exhibit 1 illustrates the
9 impact these adjustments (e.g., updating costs to reflect actuals) would
10 have on the Company's cost of service.

11 **Q. WAS SMITH SUPPLEMENTAL EXHIBIT 1 PREPARED BY YOU**
12 **OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?**

13 A. Yes.

14 **Q. PLEASE EXPLAIN THE ADJUSTMENTS THAT ARE**
15 **PRESENTED IN SMITH SUPPLEMENTAL EXHIBIT 1.**

16 A. **Line 1 - Annualize retail revenues for current rates**

17 This adjustment has been updated to reflect the change in the fuel cost
18 factors effective October 1, 2018 and a correction to billed revenues. The
19 fuel cost factors utilized in the Company's November 8, 2018 filing were
20 the Company's fuel cost factors as of October 1, 2017. The fuel cost
21 factors effective October 1, 2017 were used in the original filing because
22 the Company was unable to incorporate the fuel cost factors effective

1 October 1, 2018 due to the close proximity of the Commission's approval
2 of the factors and the filing date of this case.

3 **Line 2 – Update fuel costs to approved rate and other fuel revenue**
4 **adjustments**

5 This adjustment has been updated to reflect the change in the fuel cost
6 factors effective October 1, 2018 for the reasons provided for the
7 adjustment to Line 1.

8 **Line 3 – Adjust Other Revenue**

9 This adjustment has been added to adjust other revenue to reflect proposed
10 changes to the Basic Facilities Charges. The proposed changes are
11 discussed further in Witness Pirro's filed direct testimony.

12 **Line 4 – Adjust the amount of CWIP included in Rate Base**

13 This adjustment has been updated to reflect the actual construction work
14 in progress ("CWIP") as of December 31, 2018. The CWIP balance was
15 estimated in the Company's November 8, 2018 filing.

16 **Line 11 - Adjust for post test year additions to plant in service**

17 This adjustment has been updated to reflect the actual additions to plant in
18 service from October 1, 2018 through December 31, 2018. These
19 additions were estimated in the Company's November 8, 2018 filing. This
20 adjustment also reflects the addition of land held for future use which
21 resulted in a change in rate base and property tax expense. The land held
22 for future use included in this adjustment is the non-depreciable land costs
23 removed in Line 14.

1 **Line 12 – Reflect 2017 Lee Combined Cycle addition to plant in**
2 **service**

3 This adjustment has been updated to reflect the actual electric plant in
4 service balance for the Lee CC project to include in rate base as of
5 December 31, 2018. This balance was estimated in the Company's
6 November 8, 2018 filing. Rate base was also adjusted to include the
7 impact of bonus depreciation.

8 **Line 13 – Amortize deferred cost balance related to Lee Combined**
9 **Cycle**

10 This adjustment updates the projected Regulatory Asset balance as of May
11 31, 2019. This balance was estimated in the Company's November 8,
12 2018 filing.

13 **Line 14 – Adjust for Lee Nuclear amortization**

14 This adjustment updates the proposed Regulatory Asset balance,
15 consisting of Lee nuclear development costs, adjusted to remove non-
16 depreciable land costs and estimated expenditures through May 31, 2019.
17 This balance was estimated in the Company's November 8, 2018 filing.

18 **Line 15 – Adjust reserve for end of life nuclear costs**

19 This adjustment reflects an update to a calculation to accurately reflect the
20 impact to rate base.

21 **Line 18 - Amortize deferred environmental costs**

1 This adjustment has been updated to reflect the actual costs and plant
2 additions from October 1, 2018 through December 31, 2018. These costs
3 were estimated in the Company's November 8, 2018 filing.

4 **Line 19 - Amortize deferred cost balance related to SC AMI**

5 This adjustment has been updated to reflect the actual South Carolina
6 Advanced Metering Infrastructure ("SC AMI") plant additions from
7 October 1, 2018 through December 31, 2018. These amounts were
8 estimated in the Company's November 8, 2018 filing. Rate base was also
9 adjusted to reflect the impact of bonus depreciation.

10 **Line 22 - Normalize O&M labor expense**

11 This adjustment reflects an updated calculation to accurately reflect the
12 impact to operating income.

13 **Line 23 - Update benefits costs**

14 This adjustment has been updated to reflect the actual 2018 expenses for
15 active medical benefits. These amounts were projected in the Company's
16 November 8, 2018 filing. This adjustment also reflects an updated
17 calculation to accurately reflect the impact to operating income.

18 **Line 25 - Amortize rate case costs**

19 This adjustment has been updated to reflect the actual rate case costs from
20 October 1, 2018 through December 31, 2018. These amounts were
21 estimated in the Company's November 8, 2018 filing.

22 **Line 30 - Adjust for Customer Connect additional expense and**
23 **deferral**

1 The Customer Connect deferred balance in this adjustment was updated to
2 reflect the actual costs incurred from October 1, 2018 through December
3 31, 2018. These costs were estimated in the Company's November 8,
4 2018 filing.

5 **Line 31 - Adjust vegetation management expenses**

6 This adjustment was updated to reflect known increases in contract rates
7 that were finalized in December 2018. The amount of these increases was
8 not known at the time of the original filing.

9 **Line 32 - Synchronize interest expense with end of period rate base**

10 This adjustment has been updated to reflect a change to income taxes.
11 Specifically, because of the updates to rate base described in this
12 supplemental testimony, interest costs have been updated resulting in a
13 flow through effect to income taxes.

14 **Line 33 - Adjust 1/8 O&M for accounting and pro-forma adjustments**

15 This adjustment has been updated to reflect the changes to cash working
16 capital resulting from the other changes discussed herein.

17 **Line 34 - Adjust for Federal tax rate change**

18 This adjustment has been updated to align tax expense with the final cost
19 of service filed.

20 **Line 35 - Adjust deferred cost balance related to SC Grid**

21 This adjustment has been updated to reflect the actual SC grid
22 improvement costs and plant additions from October 1, 2018 through

657-8

1 December 31, 2018. These costs were estimated in the Company's
2 November 8, 2018 filing.

3 **Line 36 – Remove certain expenses - NEW**

4 This adjustment was added to remove expenses that may either have been
5 inadvertently booked above the line during the Test Period or
6 inadvertently allocated to South Carolina. While it is possible these
7 charges were reversed in subsequent journal entries, the Company has
8 opted to voluntarily remove the amounts from this case.

9 **Q. DOES SMITH SUPPLEMENTAL EXHIBIT 1 REFLECT ANY**
10 **CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE**
11 **COMPANY IN THIS PROCEEDING?**

12 A. No, not at this time. DE Carolinas will file an updated Smith Exhibit 1 at
13 the time of the hearing, which will incorporate the additional cost of
14 service adjustments reflected in Smith Supplemental Exhibit 1 as well as
15 other possible adjustments to cost of service to the extent the actual
16 changes are based on circumstances and events occurring up to the time
17 the hearing is closed.

18 **Q. IN YOUR OPINION, DO THESE ACCOUNTING AND PRO**
19 **FORMA ADJUSTMENTS REFLECT KNOWN AND**
20 **MEASURABLE CHANGES TO THE COMPANY'S TEST YEAR**
21 **OPERATING EXPENSES, REVENUES, AND RATE BASE?**

22 A. Yes.

III. UPDATES TO THE COMPANY'S PROPOSED EDIT RIDER

SUPPLEMENTAL DIRECT TESTIMONY OF KIM H.SMITH
DUKE ENERGY CAROLINAS, LLC

Page 8
DOCKET NO. 2018-319-E

1 Q. PLEASE EXPLAIN THE UPDATES TO THE COMPANY'S
2 PROPOSED EDIT RIDER SHOWN IN UPDATED SMITH
3 EXHIBIT 2?

4 A. Several updates were made to Smith Exhibit 2 to include actual balances
5 or more recently available information. The total impact of the updates
6 was a decrease in the Year 1 decrement rider of \$720,000 (from -
7 \$62,612,000 to -\$61,892,000), shown on Page 2, Line 6. Below is the
8 detail of the updates:

- 9 • The federal EDIT liability balances were updated as of December 31,
10 2018, as shown on Line 1a of Page 1. These updates reflect true-ups
11 that were made during 2018 to the December 31, 2017 balances.
- 12 • The ARAM rate, the amortization rate required for the federal EDIT –
13 protected balance, on line 8 of Page 1 was also updated based on a
14 more recent calculation by the Company's Tax Department.
- 15 • The deferred revenues shown on Line 4 of Page 1 and calculated on
16 Page 3 were updated with actual deferred amounts for October 1, 2018
17 through December 31, 2018. These amounts were estimated in the
18 Company's November 8, 2018 filing.
- 19 • The NC EDIT balance on Line 1a of Page 1 was updated with the
20 actual balance as of December 31, 2018. This amount reflects updated
21 activity from the December 31, 2017 balances in the Company's
22 November 8, 2018 filing.

IV. CONCLUSION

1 **Q. DOES THIS CONCLUDE YOUR PRE-FILED SUPPLEMENTAL**
2 **DIRECT TESTIMONY?**

3 **A. Yes.**

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[PURSUANT TO PREVIOUS INSTRUCTION, THE
PREFILED REBUTTAL TESTIMONY OF KIM H.
SMITH FOLLOWS HEREINAFTER]

VOLUME 4
3/21/19

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

**BEFORE
THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
DOCKET NO. 2018-319-E**

In the Matter of:

)

)

REBUTTAL TESTIMONY OF

Application of Duke Energy Carolinas,

)

LLC for Adjustments in Electric Rate

)

Schedules and Tariffs and Request for an

)

Accounting Order

)

**KIM H. SMITH
FOR DUKE ENERGY
CAROLINAS, LLC**

I. INTRODUCTION AND PURPOSE

1 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND**
2 **CURRENT POSITION.**

3 A. My name is Kim H. Smith and my business address is 550 South Tryon
4 Street, Charlotte, North Carolina. I am a Director of Rates and Regulatory,
5 employed by Duke Energy Carolinas, LLC, testifying on behalf of Duke
6 Energy Carolinas ("DE Carolinas" or the "Company").

7 **Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS**
8 **PROCEEDING?**

9 A. Yes, I did. I filed direct testimony and exhibits in this docket on November
10 8, 2018. I filed supplemental direct testimony and one exhibit on January
11 18, 2019.

12 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

13 A. The purpose of my rebuttal testimony is to respond to certain accounting
14 and ratemaking adjustments proposed by the Office of Regulatory Staff
15 ("ORS"), and to respond to the ORS' recommendations with regards to
16 deferred costs that would result in the Company not being able to fully
17 recover its prudently incurred costs.

18 **Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?**

19 A. Yes, I have included three exhibits. Smith Rebuttal Exhibit 1, which is an
20 informational filing and a revision of the original Smith Exhibit 1 filed
21 with my direct testimony. Smith Rebuttal Exhibit 1 shows the Company's
22 revised revenue requirement incorporating the Company's adjustments

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1 filed in its supplemental filing and the Company's rebuttal position in this
2 case. Smith Rebuttal Exhibit 2 shows the proposed EDIT Rider updated
3 for the change in cost of debt supported in the rebuttal testimony of
4 Company Witness Sullivan. Smith Rebuttal Exhibit 3 shows the proposed
5 Phase 1 and Phase 2 revenue requirements for the Grid Improvement Plan
6 updated for the change in cost of debt supported in the rebuttal testimony
7 of Company Witness Sullivan and for a refinement to the class allocation
8 factor discussed in the testimony of Company Witness Hager.

9 **Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER**
10 **YOUR DIRECTION AND SUPERVISION?**

11 **A.** Yes, these exhibits were prepared under my supervision.

12 **II. RESPONSE TO THE OFFICE OF REGULATORY STAFF**

13 **ACCOUNTING ADJUSTMENTS**

14 *Adjustments Not Opposed*

15 **Q. ARE THERE ANY ACCOUNTING ADJUSTMENTS WHERE THE**
16 **COMPANY AND THE ORS AGREE BASED ON THE COMPANY'S**
17 **FILING MADE ON NOVEMBER 8TH, 2018?**

18 **A.** Yes, there are nine accounting adjustments where the Company and the
19 ORS agree based on the filing the Company made on November 8, 2018.

20 #6 – Adjust for cost recovered through non-fuel riders

21 #8 – Annualize depreciation on year end plant balances

22 #9 – Annualize property taxes on year end plant balances

23 #10 – Adjust for new deprecation rates

REBUTTAL TESTIMONY OF KIM H. SMITH
DUKE ENERGY CAROLINAS, LLC

Page 3
DOCKET NO. 2018-319-E

1 #16 – Adjust for coal inventory

2 #17 – Adjust for approved regulatory assets and liabilities

3 #24 – Levelize nuclear refueling outage costs

4 #26 – Adjust aviation expenses

5 #34 – Adjust for tax rate change

6 **Q. ARE THERE ADDITIONAL ADJUSTMENTS RECOMMENDED**
7 **BY THE ORS WITH WHICH THE COMPANY AGREES?**

8 A. Yes, there are 10 recommended adjustments by the ORS either in Direct or
9 Supplemental Testimony with which the Company agrees as detailed
10 below. These adjustments reflect the update of estimates to actuals and
11 additional adjustments to the Company's cost of service as shown on
12 Smith Supplemental Exhibit. Smith Rebuttal Exhibit 1 incorporates the
13 adjustments listed below.

14 #1 – Annualize Retail revenues for current rates

15 #2 – Update fuel costs to approved rate and other fuel related adjustments

16 #3 – Adjust Other Revenue

17 #4 – Adjust the amount of CWIP included in rate base

18 #5 – Eliminate unbilled revenues

19 #11 – Adjust for post year additions to plant in service

20 #12 – Reflect 2017 Lee Combined Cycle addition to plant in service

21 #23 – Update benefit costs

22 #31 – Adjust vegetation management expenses

1 #32 – Adjust Income Taxes to Synchronize Interest Expense for the
2 Adjusted Test Year Rate Base

3 *ORS Adjustments Opposed by the Company*

4 **Q. PLEASE SUMMARIZE THE ORS'S RECOMMENDATION WITH**
5 **REGARD TO DEFERRALS.**

6 A. The ORS makes several recommendations with regards to deferred costs
7 that would in effect deny the Company recovery of prudently incurred
8 costs. These recommendations are primarily discussed in the testimony of
9 ORS Witness Payne. There are a number of deferrals in this case, which
10 include carrying costs. Carrying costs are necessary to ensure that the
11 Company recovers the full value and effect of the deferral. No one
12 contests the prudence of the expenses in the deferrals though ORS
13 devalues the deferrals by disallowing carrying costs and, in most cases,
14 significantly extending the recovery period for the deferred costs.

15 First, the ORS recommends that the Company be disallowed the
16 return on the incremental costs, which the Company has deferred in a
17 regulatory asset on its books during the deferral period. ORS Witness
18 Payne offers no justification for the disallowance other than citing the
19 portion of the order that states that "(s)uch relief will not prejudice the
20 right of any party to address the prudence of such costs in a subsequent
21 rate proceeding." If ORS Witness Payne alleges that the deferred costs
22 were imprudent, he offers no argument explaining such allegation in his
23 testimony. Second, the ORS recommends that the Company be disallowed

1 a return during the amortization period for the portion of the regulatory
2 assets that relate to operating expenses. Finally, in the testimony of ORS
3 Witness Morgan, the ORS recommends unnecessarily long recovery
4 periods for the deferred costs, increasing the amount of disallowance to
5 the Company due to the cost of money.

6 **Q. WHICH ADJUSTMENTS ARE IMPACTED BY THE ORS**
7 **RECOMMENDATIONS REGARDING DEFERRALS?**

8 A. The differences in the Company's position and the ORS's position on the
9 adjustments listed below are related to the treatment of deferrals.

10 #7 – Carolinas West Control Center Deferral Amortization

11 #13 – Amortize Deferred Cost Balance Related to Lee Combined Cycle

12 #19 – Amortize Deferred Cost Balance Related to SC AMI

13 #35 – Adjust deferred cost balance related to SC Grid

14 Later in my testimony I will discuss additional adjustments (#14, #18,
15 #25, #30). Not only does the Company oppose the ORS's recommended
16 deferral treatment of these adjustments, the Company also opposes other
17 aspects of the ORS's recommendations on these adjustments.

18 **Q. DOES THE COMPANY OPPOSE THESE ORS**
19 **RECOMMENDATIONS?**

20 A. Yes. The Company strongly opposes these recommendations as I explain
21 below and as further explained in the rebuttal testimonies of Company
22 Witnesses Ghartey-Tagoe, Wright and Hevert.

1 ORS Witness Payne recommends separating the deferred balances
2 into two categories – deferred operating expenses (including O&M,
3 depreciation expense and property taxes on plant in-service) and deferred
4 capital costs (which, under his definition, only includes deferred return on
5 capital investments). ORS Witness Payne then goes on to recommend that
6 the Company be disallowed a return on the deferred operating expenses
7 over the entire amortization period, in some cases under the ORS
8 recommendation, as long as 39 years. He argues that the Company would
9 not have earned a return had the costs not been deferred. In other words,
10 had the Company collected the costs from customers in the period which
11 the costs had been incurred, the Company would have no financing
12 requirements and would not need to earn a return. This logic is misplaced
13 and inconsistent with other carrying costs that the ORS is willing to accept
14 when they are beneficial to customers, as explained below. Moreover,
15 stretching out cost recovery to life of plant as ORS Witness Morgan did is
16 a capital-based concept. It is inappropriate to treat costs like capital costs
17 in terms of length of recovery, but not allow them to be placed into rate
18 base or collect carrying costs like undepreciated capital would receive.

19 Applying ORS logic in an even-handed manner, if the Company
20 must accept the weight of carrying costs on expenses to be paid by
21 customers, then it should also accept the benefit of carrying costs which it
22 was otherwise willing to pay customers. The inequity of the ORS
23 argument is clear when one considers deferred income taxes. Income taxes

1 are an operating expense. Deferred income taxes result from the timing
2 difference from when the Company pays the cash for the expense and
3 when the costs are recovered in customer rates. The only difference is that
4 the amounts are collected in rates before the Company pays the cash,
5 resulting in a regulatory liability, instead of a regulatory asset. In order to
6 be consistent in its position, the ORS would need to also recommend
7 removing the deferred tax liabilities from rate base since these are the
8 result of deferred operating expenses. For DE Carolinas, the accumulated
9 deferred income tax plus excess deferred income tax balances included as
10 a reduction to rate base in this case are \$1.7 billion. Removing these items
11 from rate base would result in a 30 percent increase in rate base. If the
12 ORS were to consistently apply its logic, it would be a significant
13 detriment to customers if taken to its logical conclusion.

14 The appropriate and more equitable treatment, and the one
15 proposed by the Company, is to continue to include the deferred taxes in
16 rate base recognizing that the Company has additional cash that can be
17 used to finance utility investments and customers should receive a return
18 on the Company's use of that cash. In the same way, the regulatory assets
19 resulting from the Commission approved deferrals, including the deferred
20 operating expenses, are appropriate to include in rate base because there is
21 a timing difference between when amounts are paid and when they are
22 collected from customers. During this time, the Company must incur

1 additional financing costs related to the cash it has borrowed for the
2 amounts it has expended but not yet collected from customers.

3 In his testimony, ORS Witness Payne references that the National
4 Association of Utility Commissioners ("NARUC") Rate Case and Audit
5 Manual states that regulatory assets and other deferrals should be
6 examined to determine if the deferred costs are appropriate to be included
7 in rate base. The manual says nothing about splitting the regulatory assets
8 between deferred operating expenses and deferred capital costs. I have
9 never heard of this concept before and, as far as the Company can tell, the
10 ORS developed this idea in isolation without any supporting industry
11 manuals, documentation or precedent. The NARUC manual that ORS
12 Witness Payne refers to states:

13 "In looking at the nature of the deferrals, the auditor should
14 consider whether the deferral is appropriate for inclusion in rate
15 base. For instance, is the utility deferring certain fuel or purchased
16 power expenses under a mechanism that is approved by the
17 Commission allowing for dollar-for-dollar recovery of those
18 costs?" (Pages 22-23)

19 Consistent with what this manual appears to be referring to, the Company
20 does not and is not proposing in this case to earn a return on its deferred
21 fuel balances. The deferred balances at question in this case are very
22 different, and both the Company and the ORS have proposed multi-year
23 recovery periods. While the Company would still disagree, if the ORS

1 were proposing recovery of the deferred costs through a one-year rider,
2 their proposed rate base treatment would at least be more logical and
3 consistent with the NARUC manual. That is not the case.

4 The ORS recommendations discussed above suggest a business
5 can borrow money for free. However, investors do not provide interest free
6 loans.

7 **Q. HOW WOULD YOU SUMMARIZE THE COMPANY'S POSITION**
8 **ON RETURNS ON DEFERRALS?**

9 A. Deferrals, by definition, recognize that the Company is incurring a cost
10 that is not currently recovered in customer rates. The Company is
11 incurring costs related to these deferrals. Those costs, whether designated
12 as capital or operating for accounting purposes, require cash. That cash
13 must be obtained from the Company's debt and equity investors. And
14 those investors require interest, or a return, on the cash they have invested
15 in the Company. These financing costs (the return on the deferred costs)
16 are a real cost that the Company incurs and to disallow recovery of these
17 costs during the deferral period or the amortization period would be to
18 disallow prudently incurred costs.

19 **Q. WHAT IS YOUR RESPONSE TO THE AMORTIZATION PERIOD**
20 **LENGTHS PROPOSED BY ORS WITNESS MORGAN?**

21 A. The chart below shows the deferrals for which ORS Witness Morgan
22 recommends lengthy amortization periods far longer than what the
23 Company recommends.

Adj #	Adjustment	Deferred Balance (\$000)	Length of Amortization in years	
		Company Position	Company Position	ORS Position
SC -0700	Carolinas West Control Center	5,344	3	30
SC -1300	Lee CC Combined Cycle	22,913	3	39
SC -1900	SC AMI	35,957	3	15
SC -3500	SC Grid	6,160	2	5

1 While exact amortization periods are subjective, there needs to be a
2 balance and consideration of both the impact on customer rates and the
3 impact on the Company's cash flow. Given the deferred balances, the
4 amortization periods proposed by ORS Witness Morgan are excessive and
5 unnecessarily long for these deferrals. In addition, since the ORS has
6 recommended to disallow the return during the amortization period, the
7 longer amortization periods exacerbate the disallowance. Therefore, the
8 Company opposes these recommendations. Again, the logic is
9 contradictory. ORS doesn't support a return because the costs were not
10 originally classified as capital, but then turns around and treats them like
11 capital by proposing such lengthy amortization periods.

12 **Q. PLEASE DESCRIBE THE COMPANY'S RESPONSE TO THE**
13 **REMAINING ORS PROPOSED ADJUSTMENTS.**

14 **A.** The Company opposes the ORS recommendations on the remaining
15 adjustments. The Company's position on the remaining ORS adjustments
16 are explained below.

1 **Adjustment #14 –Adjust for Lee Nuclear amortization**

2 The Company does not oppose the ORS's adjustment to remove certain
3 costs associated with the design of a visitor's center from the balance
4 related to Lee Nuclear; however, the Company does oppose ORS Witness
5 Morgan's recommendation for the Company not to earn a return on the
6 unamortized balance of the deferred project development costs as
7 discussed above. If the Commission agrees the project development costs
8 have been prudently incurred, then it is appropriate for the Company to
9 recover its financing costs that will be incurred during the amortization
10 period, as amounts are collected from customers over time. Moreover,
11 allowing a return would be appropriate and fair given that the costs for
12 V.C. Summer, which were of a far greater magnitude, are being recovered
13 with a return. To not allow a return for Lee Nuclear costs would be
14 punitive and arbitrary.

15 **Adjustment #18 –Amortize deferred environmental costs**

16 The Company opposes the adjustments recommended by the ORS. First,
17 the ORS recommends disallowing a portion of the returns on the
18 components of the deferral relating to capital investments at operating
19 plants. The punitive nature of the adjustment recommended by Witness
20 Payne to disallow the return on the deferred costs for this component
21 during the deferral period and not earn a return during the time period
22 when the costs are being recovered (amortization period) is discussed
23 above. The Company also vigorously opposes the ORS recommendations

1 to disallow certain coal ash related costs for the reasons set forth in the
2 rebuttal testimony of Company Witnesses Kerin and Wright.

3 **Adjustment #20 – Normalize for storm costs**

4 The Company's pro forma adjustment normalizes storm restoration costs
5 to the average level of costs the Company experienced over the past ten
6 years. However, ORS Witness Morgan recommends eliminating the
7 expenses in the highest and lowest years to use an eight-year average
8 expense level. The Company does not oppose this component of the ORS
9 adjustment. However, the ORS adjustment also removes the inflation
10 impact to storm costs, which is not described in ORS's testimony and has
11 a larger impact on the average. The Company does oppose this component
12 of the ORS's adjustment, as it is unreasonable and ignores the current
13 costs implicated in addressing storms.

14 The Company's adjustment adjusts each storm cost year included
15 in the ten-year average to be comparable to the test year on an inflation
16 adjusted basis. This is appropriate because as with the costs of other goods
17 and services, the costs associated with storm restoration – e.g., the costs
18 for contract labor, such as line workers and tree professionals, materials,
19 and staging and logistics – have increased significantly in the last ten
20 years. In fact, the average annual inflation rate calculated by the Company
21 for the ten years beginning in 2008 is 1,422 percent per year, or 14.22
22 percent over the ten-year period. This adjustment is more than reasonable
23 given that DE Carolinas' contract labor costs alone have increased 45

1 percent from 2008 to 2017.¹ By removing the Company's inflation
2 adjustment, the ORS seems to be implying that the Company should be
3 able to hire contractors to work on storm restoration in 2019 for the exact
4 same hourly rate it paid them in 2008. This is not realistic, and this portion
5 of the ORS adjustment should be rejected by the Commission. Smith
6 Rebuttal Exhibit 1, Page 3, Line 20 updates this adjustment to reflect the
7 ORS's recommendation to use an eight-year average, but continues to
8 include inflation adjusted costs in the average.

9 **Adjustment #21 –Annualize O&M non-labor expenses**

10 The Company's adjustment annualized Test Period O&M expenses
11 (excluding fuel, purchased power, and labor costs) to reflect the change in
12 costs that occurred during the test period. ORS Witness Smith proposes to
13 exclude this adjustment because "it is based on projected and estimated
14 data rather than known and measurable expenses." This is not true and the
15 Company maintains that its adjustment is appropriate. First, the purpose
16 of the Company's proposal is not to project O&M expenses, but instead to
17 annualize the impacts of inflation to an end of test period level. The
18 adjustment takes actual known and measurable inflation metrics
19 (Consumer Price Index and Producer Price Index) and compares the
20 average of the test period to the end of test period metrics. These metrics
21 for the 2017 test period are historic, known and measurable, and publicly

¹ This percentage is based on on-system contractor rates for 2008 and 2017. These are the contractors that DE Carolinas uses on its system on a regular basis, and relies upon when there is a storm event.

1 available from the U.S. Bureau of Labor Statistics. This adjustment is very
2 similar to the customer growth adjustment which the ORS has not
3 rejected. The customer growth adjustment compares the average number
4 of customers during the test period to the end of test period number of
5 customers in order to annualize the impacts of customer growth to an end
6 of test period level. Both adjustments annualize impacts – one for
7 customer growth and one for inflation – and both are appropriate to
8 include.

9 **Adjustment #22 –Normalize O&M labor expenses**

10 The Company's adjustment adjusts the wages and salaries and related
11 employee benefit costs to reflect annual levels of costs as of July 1, 2018
12 and also reflects changes in related payroll taxes. The ORS recommends
13 updating the salary allocator for DEC to the same date as the O&M labor
14 expense, July 1, 2018, and the Company does not oppose this portion of
15 the ORS recommendation. However, the Company does not agree with
16 ORS Witness Smith's recommendation to remove 50 percent of the
17 Company's long and short term incentive ("LTI" and "STI") program
18 costs for the reasons discussed by Company Witness Metzler.

19 **Adjustment #25 –Amortize rate case costs**

20 The Company opposes this adjustment recommended by ORS Witness
21 Payne to disallow the Company to earn a return on the deferred costs
22 during the deferral period and not earn a return during the time period
23 when the costs are being recovered is discussed above. The Company

1 also opposes ORS Witness Smith's recommendation to disallow certain
2 rate cases expenses due to alleged insufficient documentation to support
3 the costs. The expenses being challenged are legal services provided by
4 outside counsel which are billed to the Company using an e-billing
5 system. Upon contacting the ORS to determine the level of detail they
6 would need to determine the documentation was sufficient, I learned that
7 only a paper invoice would suffice. An e-billing system has been utilized
8 at Duke for the last several years. It is a commonly used platform and not
9 unusual for a large company to utilize for administrative efficiency.
10 Instead of paper invoices, outside vendors are given login credentials to
11 access the system where they input all relevant billing information (date,
12 matter, rate, hours, description of work performed, etc.) directly into the
13 system. Once the information is entered, the approving attorney is
14 prompted to access the system, review the information and approve or
15 deny the invoice. At all times, the information is provided, communicated
16 and stored electronically. When a data request is made to review the
17 billing data, the system exports the data to Microsoft Excel, which is
18 supplied as the response. For legal invoices, the descriptions of work
19 performed are reviewed for privileged information before providing.
20 During discussions with the ORS the Company offered to provide
21 screenshots of the data in the system, redact the privileged information by
22 hand before submitting to them or have our vendors sign affidavits
23 attesting that they have reviewed the information the Company is

1 providing to the ORS and that it is true and accurate. At the time of this
2 testimony, the Company has not heard back from the ORS but notes that
3 its expenses were reasonably and prudently incurred and no justifiable
4 reason for disallowance has been given.

5 **Adjustment #29 –Adjust O&M for executive compensation**

6 The ORS agrees with the Company's adjustment to remove 50 percent of
7 the compensation of the four Duke Energy Executives with the highest
8 level of compensation allocated to DE Carolinas in the test period.
9 However, since ORS Witness Smith proposed to remove 50 percent of
10 incentives for all employees in adjustment #22, she added back the 50
11 percent of incentives for the top four executives in this adjustment. The
12 Company does not agree with ORS Witness Smith's recommendation
13 related to the incentive pay components for all employees, including
14 linemen, call center representatives, etc., for the reasons discussed by
15 Company Witness Metzler. However, the Company excluded 50 percent of
16 the compensation, including incentives, of its top four executives in its
17 original filing, and I have kept that exclusion in this adjustment in Smith
18 Rebuttal Exhibit 1, rather than moving it to Adjustment #22 as ORS
19 Witness Smith has.

20 **Adjustment #30 –Adjust for Customer Connect Project**

21 The Company has included costs related to its Customer Connect project
22 which will replace the Company's current billing system and is currently
23 planned to be placed in service in 2022. Due to the nature of the costs, a

1 significant portion of the spending between now and the in-service date
2 will be O&M. The ORS has made two recommendations to the
3 Company's adjustment which the Company opposes. The Company's
4 opposition to the ORS recommendations regarding deferrals are discussed
5 earlier in my testimony. In addition, the ORS recommends removing the
6 Company's proposed increase to O&M. ORS Witness Payne states these
7 costs should be removed because they are not known and measurable
8 (page 13). As stated in my direct testimony, these costs are based on
9 signed contracts. Portions of the costs are based on amounts specified in
10 the contracts and the remaining amount can be reasonably estimated based
11 on the activities the Company is obligated to in the contract. This is
12 comparable to O&M for a new generation plant. When a new plant is
13 placed in service, the Company is obligated to operate and maintain that
14 plant and the Company's obligation is known and can be reasonably
15 measured. The exact level of O&M is not known, but an approximate level
16 can be reasonably estimated based on experience operating similar plants.
17 To allow a utility no level of O&M in rates for the new plant would be
18 unreasonable. Similarly, to allow the Company no level of O&M, or solely
19 the amount in the test period of \$640,000, for Customer Connect would
20 also be unreasonable. At a minimum, the Company's actual O&M in 2018
21 of \$3,189,000, should be allowed. However, the Company believes its
22 proposed amount of \$4,665,000 is reasonable and should be allowed.
23 Company Witness Hunsicker, in both her direct and rebuttal testimony,

1 details the benefits the system will provide to customers and the
2 Company's commitment to incur the costs through signed contracts.
3 Removing from this case the operating expenses needed to implement the
4 project is the same as denying the Company the opportunity to recover
5 those costs for a new billing system which no one has contested.

6 I will note that an alternative that would still allow the Company
7 to recover these costs is for the Commission to approve a continuation of
8 the deferral of the incremental operating expenses incurred related to the
9 Customer Connect project, including a carrying charge on the deferred
10 costs, until the Company's next general rate case. This would be a
11 reasonable alternative to the Company's adjustment related to Customer
12 Connect and would be similar to the treatment agreed to in partial
13 settlement and approved by the North Carolina Utilities Commission in
14 the Company's recent North Carolina rate case.²

15 **Adjustment #33 –Adjust 1/8 O&M for accounting and pro forma**
16 **adjustments**

17 The Company's rate base is adjusted to include the additional working
18 capital required as a result of the additional O&M expenses the Company
19 is proposing in this proceeding. ORS proposes an adjustment to working
20 capital which reflects ORS adjustments to O&M expenses. To the extent
21 that Company does not agree with certain of the ORS's proposed O&M

² Order dated June 22, 2018, in North Carolina Utilities Commission Docket No. E-7 Sub 1146.

1 expense adjustments for the reasons discussed in my testimony, the
2 Company disagrees with the ORS's amount for this adjustment. However,
3 we agree on the concept of and the method used to calculate this
4 adjustment.

5 **Adjustment #36 –Remove Certain Expenses**

6 The Company opposes this adjustment. The ORS recommends removing
7 O&M expense of \$2,399,000, from the test period for costs ORS Witness
8 Smith characterized as “sponsorships, lobbying expenses, service awards,
9 advertising and other miscellaneous items.” The Company reviewed the
10 same transactions that the ORS reviewed and has agreed to remove
11 \$227,033 from O&M expense. After the Company's adjustment, there are
12 no lobbying costs or image-building advertising costs in this case.

13 However, the items in the ORS's adjustment the Company
14 disagrees with removing in this proceeding primarily fall into the
15 following categories:

- 16 1. **Employee incentives, service & safety awards, and any costs to**
17 **recognize and reward the Company's employees who serve our**
18 **customers.** The appropriateness of these costs is addressed in the
19 rebuttal testimony of Company Witness Metzler.
- 20 2. **Lineman's Rodeo costs.** The Lineman's Rodeo is an industry
21 event where linemen share best practices and compete in events
22 where they have the opportunity to display and hone their skills as
23 linemen to provide reliable service (ex. Pole top rescue, proper

1 insulation techniques) to the benefit of our customers. Prior to the
2 event, linemen are training to prepare for the event, which has the
3 benefit of additional preparation for their jobs. The appropriateness
4 of these costs is addressed in the rebuttal testimony of Company
5 Witness Metzler.

6 3. **Organization dues.** These membership dues for local South
7 Carolina Chambers of Commerce and other local South Carolina
8 organizations that promote economic development in South
9 Carolina, such as Visit Greenville SC and the Spartanburg
10 Development Association, are appropriately included in the case.
11 Chamber of Commerce organizations promote policies, initiatives
12 and principles that benefit all citizens through economic
13 investments, job creation and retention, strong schools, and
14 attracting and retaining business development. As the Greenville
15 Chamber of Commerce puts it, "the Chamber mission is to lead,
16 convene and mobilize the business community to drive regional
17 economic growth." Membership in the various Chambers of
18 Commerce and other Civic organizations is an integral part of
19 managing our business responsibly on behalf of our customers and
20 keeping in contact with a very important segment of our
21 customers."

22 Funds paid to these organizations that are not specified as a
23 donation or lobbying on the invoice are generally in support of

1 business, economic development and the communities we serve. It
2 is reasonable, as explained by Witness Ghartey-Tagoe, that the
3 Company participates in these organizations to best serve the
4 communities in which our customers live and in which we operate.

- 5 4. **Costs that are not 100 percent related to South Carolina.** The
6 ORS removed several transactions that it labeled as “not related to
7 SC.” For example, the ORS removed registration fees paid to the
8 North Carolina Department of Motor Vehicles (“DMV”) for
9 transmission vehicles. However, the ORS made no adjustment to
10 accept the full cost of fees paid to the South Carolina DMV that
11 were also allocated between North Carolina and South Carolina.
12 Transmission assets are considered system assets and the costs to
13 maintain those assets, including registration fees on company
14 vehicles, are appropriately allocated to all customers based on peak
15 demand. Therefore, the Company allocated the registration fees for
16 transmission vehicles paid to both the North Carolina and the
17 South Carolina Departments of Motor Vehicle to all customers
18 based on a transmission allocator. On other costs that could be
19 direct assigned by state, such as bill inserts, the ORS
20 recommended removing the costs for North Carolina bill inserts
21 that were allocated between North Carolina and South Carolina,
22 but did not recommend direct assigning 100 percent of the costs
23 for South Carolina bill inserts to South Carolina. If the ORS had

1 direct assigned both North Carolina and South Carolina bill insert
2 costs, it likely would have ended up in a similar place as the
3 Company achieved through applying an allocator based on number
4 of customers. The key point is that the ORS is focused on what
5 costs South Carolina customers should not pay, but ignores the
6 effect of that same logic on what costs South Carolina customers
7 should bear under that same theory.

8 **5. Timing differences.** The Company believes that the 2017 test year
9 amount requested for recovery in this proceeding is representative
10 of the Company's expenses for a 12-month period. The ORS
11 removed various transactions due to the invoice date and the date
12 the invoice was paid being in different calendar years. For
13 example, if the invoice was dated 2016 and paid in 2017 the ORS
14 removed the expense from the test year. However, this ignores the
15 fact that the Company uses accrual accounting. When the expenses
16 are incurred, the Company will accrue an estimated expense if the
17 amount meets a certain threshold per the Company's accrual
18 policy. Then, when the invoice is received and processed, which
19 may be the following calendar year, the Company reverses the
20 accrual and books the actual expense. This suggests the ORS
21 believes unless an expense is paid in the year it is incurred it
22 should not be recovered from customers, ignoring the concept of
23 accrual accounting in the removal of these expenses.

1 6. Litigation expenses - The Company opposes ORS witness
2 Smith's updated adjustment removing litigation expenses for the
3 reasons set forth in the rebuttal testimony of Company Witness
4 Wright.

5 **Adjustment #37 –Customer Growth.** While the amounts calculated by
6 the Company and ORS for this adjustment are different based on other
7 areas of disagreement, we agree on the concept of and the method used to
8 calculate this adjustment.

9 **Adjustment #38 –Adjust Revenue, Taxes and Customer Growth for**
10 **the Proposed Increase.** While the amounts calculated by the Company
11 and ORS for this adjustment are different based on other areas of
12 disagreement, we agree on the concept of and the method used to calculate
13 this adjustment.

14 *Remaining Adjustments Opposed by the Company*

15 **Q. OF THE REMAINING ADJUSTMENTS THAT THE COMPANY**
16 **OPPOSES, WHICH ONES ARE RESPONDED TO BY OTHER**
17 **COMPANY WITNESSES?**

18 **A. The following ORS adjustments from Audit Exhibit GS-1, are responded**
19 **to by other Company witnesses in rebuttal testimony**
20 **Change in debt cost rate from 4.63 to 4.44 percent**

21 The Company does not oppose updating the cost of debt, but recommends
22 a rate of 4.53 percent, reflecting the cost of debt financing through

1 December 2018. This adjustment is further discussed in the rebuttal
2 testimony of Company Witness Sullivan.

3 **Change in return on equity from 10.50 to 9.30 percent**

4 The Company opposes this adjustment for the reasons set forth in the
5 rebuttal testimony of Company Witness Hevert.

6 **Adjustment #15 – Adjust reserve for end of life nuclear costs**

7 The Company opposes this adjustment for the reasons set forth in the
8 rebuttal testimony of Company Witness Capps.

9 **Adjustment #28 – Adjust for credit card fees**

10 The Company opposes this adjustment for the reasons set forth in the
11 rebuttal testimony of Company Witness Quick.

12 **Q. DO YOU HAVE ANY RESPONSE TO PARTIES WHO ARGUE**
13 **THAT THE “STEP UP” RATE INCREASES DESCRIBED IN THE**
14 **COMPANY’S DIRECT CASE ARE INAPPROPRIATE?**

15 A. Yes. For all the reasons described in the Company’s direct case, we
16 continue to think we proposed an appropriate and reasonable manner in
17 which to recover Grid Improvement Costs. I’m not a lawyer, but from my
18 view we proposed a procedure that would allow for prudence
19 determination and notice to customers that meet the requirements for
20 ratemaking as I understand them.

21 **Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

22 A. Yes.

1 **MS. H. SMITH:** Mr. Chairman and members of the
2 Commission, at this time the witnesses are
3 available for questions.

4 **CHAIRMAN RANDALL:** Thank you.

5 Okay we're just going to use my list, but I've
6 got Vote Solar. Do you have any – and if you don't
7 have cross, you can just say no cross.

8 **MR. CULLEY:** Yes, I do have cross.

9 **CHAIRMAN RANDALL:** If you would step up to the
10 microphone.

11 **MR. CULLEY:** Good morning, Mr. Chairman, and
12 members of the Commission, Hearing Officer. My
13 name is Thad Culley, Regional Director and
14 regulatory counsel for Vote Solar.

15 First, I want to say thank you for giving me
16 the privilege of appearing before you as pro hac
17 vice. I do appreciate that, and will do my best
18 not to wear out my welcome. So thank you.

19 **CHAIRMAN RANDALL:** Good plan.

20 **MR. CULLEY:** I have pre-circulated some
21 hearing exhibits that I will reference as I go
22 through, and will direct my questions specifically
23 to Mr. Gharthey-Tagoe.

24 **MS. H. SMITH:** Mr. Culley, if you don't mind,
25 can the witness have just a moment or two to look

1 at the document?

2 MR. CULLEY: Oh, absolutely.

3 MS. H. SMITH: I don't want to slow us down,
4 but I'd like for him to be able to look through it,
5 just real quickly.

6 MR. CULLEY: Absolutely. Thank you.

7 [Brief pause]

8 CROSS EXAMINATION

9 BY MR. CULLEY:

10 Q So, first, would it be accurate to state your position
11 in your prefiled direct testimony was that, in proposing
12 a \$28 BFC, you were just simply going where the numbers
13 in the cost-of-service study led you?

14 A [GHARTEY-TAGOE] That's correct.

15 Q And to be clear, with the letter notice that the company
16 submitted yesterday, there's nothing in that letter that
17 would change the company's math on reaching that
18 potential theoretical BFC of \$28; is the correct?

19 A [GHARTEY-TAGOE] That's correct.

20 Q And would you agree that a BFC of \$11.96 is within –
21 we'll use a term of art – the general ballpark of what
22 the witness for Vote Solar, Mr. Barnes, identified as
23 his maximum theoretical BFC?

24 A [GHARTEY-TAGOE] That is correct.

25 Q But you do recognize that, despite the proximity of

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1 those numbers, there remain significant differences
2 between parties on the method used to get there.

3 A [GHARTEY-TAGOE] Yes, I agree.

4 Q Would you agree with me that a change in the cost-of-
5 service methodology is not a trivial matter?

6 A [GHARTEY-TAGOE] I agree with that.

7 Q And based on your experience as a regulatory lawyer and
8 working with a utility, it would not be surprising for
9 the Commission to weigh in on the merits of a change in
10 cost-of-service methodology, would it?

11 A [GHARTEY-TAGOE] It would not.

12 CHAIRMAN RANDALL: Make sure you get close to
13 that mic, because we can't hear you in the back.
14 They heard you that time, but other times they
15 didn't.

16 BY MR. CULLEY:

17 Q And would you also agree that ratemaking is not an
18 objective science? I'd maybe state it another way, that
19 there are subjective choices made along the way that
20 influence in a material way where you land?

21 A [GHARTEY-TAGOE] I agree with that.

22 Q With all that said, is the company's objective to pursue
23 approval in future cases of a BFC that reaches the
24 theoretical maximum it could hit?

25 A [GHARTEY-TAGOE] I don't think we've made that decision.

1 Q Okay. Would you agree with me that the company's choice
2 of the cost-of-service method in this case kind of
3 determined the upward limit of what the company could
4 seek for a BFC?

5 A [GHARTEY-TAGOE] Based on the cost-of-service study, yes.

6 Q And if the Commission were to reject this new approach,
7 the minimum system approach, that would, in effect,
8 reject that higher upward limit?

9 A [GHARTEY-TAGOE] Based on that cost-of-service study,
10 yes.

11 Q Okay. Now at this time, I'd like to turn to the first
12 document I handed out. And I will put this on – I
13 believe we called this the ELMO, is that correct?

14 CHAIRMAN RANDALL: That's correct.

15 MR. CULLEY: Let me give this just a second
16 and see if we can [indicating] – there we go. And
17 I would ask that this be marked for identification
18 as a hearing exhibit. Would it be No. 1?

19 CHAIRMAN RANDALL: No, this will be Hearing
20 Exhibit No. 11.

21 [WHEREUPON, Hearing Exhibit No. 11 was
22 marked for identification.]

23 BY MR. CULLEY:

24 Q Mr. Gharthey-Tagoe, do you recognize this docket and case
25 number as being a Duke Energy Carolinas rate case from

1 the year 2011?

2 A [GHARTEY-TAGOE] That's what the document shows, yes.

3 Q And this is the testimony of Jeffrey Bailey, who was a
4 rate design witness; is that correct?

5 A [GHARTEY-TAGOE] That's what the document shows.

6 Q Now, if you could turn for me, please, to the second
7 page, there's Bates numbering there for the page number
8 002, and you will see -- if you look on line seven
9 through eight, do you see that the witness says, I
10 quote, "The cost-of-service study supports a BFC for
11 residential service of approximately \$13.67 per customer
12 per month"?

13 A [GHARTEY-TAGOE] I see that.

14 Q I thank you. And could you now look at lines 17 through
15 21 where the witness says, "We propose to increase the
16 BFCs to better reflect the cost to serve these customer
17 groups. In most cases, we propose to increase the
18 charges by approximately one-third of the difference
19 between the current BFCs and those charges determined in
20 the cost-of-service study indicated above. Based on
21 this methodology, we propose the following BFCs: Rate
22 Schedule RS and RE, \$8.72..." and I'll stop there. Do
23 you see that?

24 A [GHARTEY-TAGOE] I do.

25 Q So would you agree, in this 2011 case, the cost-of-

1 service study appears to support a maximum or
2 theoretical BFC of \$13.67?

3 A [GHARTEY-TAGOE] That's what the document says.

4 Q And that's where the numbers would lead you, if you were
5 to seek full cost recovery of those customer unit costs,
6 at that time?

7 A [GHARTEY-TAGOE] Based on that cost-of-service study,
8 yes.

9 Q Okay. And, now, if we could please turn to the very
10 back of this document, it's the Bates number 004. And
11 this should say, in the upper left-hand corner, Docket
12 No. 2013-59-E, and do you recognize that as being the
13 company's 2013 rate case?

14 A [GHARTEY-TAGOE] Well, that's what the document says.

15 Q And do you see the columns titled "Theoretical BFC,"
16 "Calculated BFC," and "Current BFC"?

17 A [GHARTEY-TAGOE] I do.

18 Q And do you see in the Residential row that the
19 theoretical BFC for this case was \$13.87?

20 A [GHARTEY-TAGOE] I do.

21 Q And for the current BFC, that would be \$7.29; is that
22 correct?

23 A [GHARTEY-TAGOE] That is correct.

24 Q And would you accept that the difference between this
25 theoretical and actual is \$6.58? Maybe subject to

1 check?

2 A [GHARTEY-TAGOE] Subject to check, that looks like the
3 right math.

4 Q And on the column that says the increase for the
5 Residential row, that is \$2.19; is that correct?

6 A [GHARTEY-TAGOE] That's correct.

7 Q And is that consistent with the 30 percent increase the
8 company had pursued in 2011?

9 A [GHARTEY-TAGOE] That's correct.

10 Q Okay. Now, in your rebuttal testimony, you state that
11 Mr. Pirro's recommendation was to take about 50 percent
12 that gap revenue, using the minimum system method; is
13 that correct?

14 A [GHARTEY-TAGOE] That's correct.

15 Q Okay. So would you agree with me, at least, that in a
16 couple of ways the company's practice now is departing
17 from the past practice?

18 A [GHARTEY-TAGOE] Yes.

19 Q Okay.

20 A [GHARTEY-TAGOE] Well, the practice in the cases you just
21 cited, yes.

22 Q Yes, thank you.

23 MR. CULLEY: I think at this time I'm going to
24 skip ahead and go to a second hearing exhibit,
25 which I'll identify here [indicating] and ask that

1 it be marked for identification. I believe that
2 will be Hearing Exhibit 12 now?

3 **CHAIRMAN RANDALL:** It will be Hearing Exhibit
4 No. 12.

5 [WHEREUPON, Hearing Exhibit No. 12 was
6 marked for identification.]

7 **BY MR. CULLEY:**

8 **Q** Mr. Gharthey-Tagoe, do you have that in front of you?

9 **A** [GHARTEY-TAGOE] I do.

10 **Q** If you could look at page three, this is a data request
11 to the company from ORS, and it's ORS Rates Request 3-4
12 – I'm sorry – 13-4. And do you see where there's a
13 table on that page titled "Basic Facilities Charge Using
14 The Basic Customer Method"?

15 **A** [GHARTEY-TAGOE] Yes.

16 **Q** And can you read for me the amount of the theoretical
17 BFC for the row "Residential (RS)"?

18 **A** [GHARTEY-TAGOE] Sixteen dollars and two cents [\$16.02].

19 **Q** And you might agree with me, the parties might challenge
20 whether or not that number is accurate. Intervenors
21 tend to do that.

22 **A** [GHARTEY-TAGOE] Yes, I wouldn't be surprised.

23 **Q** Now, did you take part in the decision to approve this
24 specific methodology for the case, the minimum system
25 versus the basic customer method?

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1 A [GHARTEY-TAGOE] I did.

2 Q And in making that choice, were you given a menu of
3 options, say, door number one leads to the basic
4 customer method and a BFC of \$16; door number two leads
5 to \$28?

6 A [GHARTEY-TAGOE] Well, not that specific in terms of what
7 the – you know, but it was a choice of cost-of-service
8 study in the start of preparing for the case. And I
9 certainly had the understanding that the method that was
10 selected for this case would result in a higher cost
11 than the method that had been selected in previous
12 cases.

13 Q Sure. And based on this data response, do you agree
14 that difference would be about \$12?

15 A [GHARTEY-TAGOE] Yes.

16 Q And are you aware of a 1991 order by this Commission,
17 Order No. 91-1022, that rejected the use of the minimum
18 system method for Duke Power?

19 A [GHARTEY-TAGOE] I am aware of a Commission decision that
20 rejected that, yes.

21 Q And could you confirm with me that this current case
22 represents the first case since 1991, before this
23 Commission, where this company or any of its
24 predecessors attempted to use the minimum system? Are
25 you able to confirm that?

1 A [GHARTEY-TAGOE] I haven't been involved in all the
2 previous rate cases, but that's my understanding.

3 Q Okay. Well, let's return to this exhibit, and this is
4 really my last couple of questions. It might involve a
5 little bit of math. So, let's -- I'll go gently.

6 A [GHARTEY-TAGOE] But before you move on, I would say, you
7 know, the fact that a commission decides something years
8 ago doesn't mean that, based on changes in policy or
9 changes in circumstances, that they can't take a
10 different position. The methodology we proposed in this
11 case has been approved by other commissions, including
12 fairly recently by the North Carolina Commission.

13 Q Okay. And are you aware there's some disagreement
14 between the North Carolina Commission -- I'm thinking
15 particularly of Commissioner Clodfelter, who filed a
16 dissent in the most recent case of questioning the
17 continued applicability or wisdom of using the minimum
18 system?

19 A [GHARTEY-TAGOE] I'm aware he filed a dissent in the
20 case, yes. But the majority voted for it.

21 Q That's right. Dissents are rarely quoted by the
22 winners. So let's go back to this exhibit where the
23 company calculated the theoretical BFC of \$16.02. Would
24 you agree the difference between the theoretical maximum
25 BFC and the current BFC is about \$7.73?

1 A [GHARTEY-TAGOE] Which exhibit are you on now?

2 Q Oh, I am sorry. This is – it's still up on the ELMO

3 here. Hearing Exhibit 12 on page three.

4 A [GHARTEY-TAGOE] Okay. I'm with you now.

5 Q Okay. So, subject to check, would you agree that the

6 gap between the actual and theoretical is \$7.73?

7 A [GHARTEY-TAGOE] Yes.

8 Q Okay. And would you accept, subject to check, that 30

9 percent of that gap, \$7.73, would result in a number

10 amount of \$2.32?

11 A [GHARTEY-TAGOE] Subject to check, yes.

12 Q Okay, thank you. So let's assume the Commission rejects

13 the minimum system method and accepted \$16.02 as the

14 theoretical BFS in this case. If the Commission forced

15 the company to follow its prior practice, would you

16 agree the BFC increase would go from \$8.29 to \$10.61?

17 A [GHARTEY-TAGOE] That math would work, yes. But it

18 doesn't mean that, if we used that method, that's what

19 we would have proposed in this case.

20 Q I really do appreciate your answers, and thank you, very

21 much.

22 A [GHARTEY-TAGOE] Thank you.

23 MR. CULLEY: And, Mr. Chairman, at this time,

24 I'd like to move for admission of these hearing

25 exhibits.

1 **CHAIRMAN RANDALL:** They're already – wait,
2 hang on. Okay. So, yes, they are accepted and
3 entered properly.

4 [WHEREUPON, Hearing Exhibit Nos. 11 and
5 12 were received in evidence.]

6 **MR. CULLEY:** Thank you.

7 **CHAIRMAN RANDALL:** Okay. NAACP, Coastal
8 Conservation League, Upstate Forever.

9 **MR. NEAL:** Good morning, Mr. Chairman,
10 Commissioners. I'm David Neal, on behalf of South
11 Carolina NAACP, Coastal Conservation League, and
12 Upstate Forever.

13 **CROSS EXAMINATION**

14 **BY MR. NEAL:**

15 **Q** Good morning, Mr. Gharthey-Tagoe. My questions will be
16 for you. And we're going to stick for a minute on this
17 question of the basic facilities charge. Given your
18 role with the company, you agree that rates approved by
19 this Commission have to be just and reasonable and not
20 unduly discriminatory; isn't that right?

21 **A** [Gharthey-Tagoe] I agree with that.

22 **Q** And you'd also agree that the burden is on your company
23 to justify any proposed rate adjustments?

24 **A** [Gharthey-Tagoe] I agree with that.

25 **Q** And just to make sure we're clear, the only

1 justification that the company has provided for its
2 proposed increase in the basic facilities charge comes
3 from the use of the minimum system method that you were
4 just discussing with Mr. Culley in the cost-of-service
5 study; isn't that right?

6 A [G HARTEY-TAGOE] Yes, and the general principle that
7 customers should bear the costs that we believe are
8 incurred to make the electricity available to them.

9 Q I understand that's your company's position, but just to
10 be clear, it is the use of the minimum system
11 methodology that came up with that figure?

12 A [G HARTEY-TAGOE] Correct.

13 Q Now, you also testified in your direct that, with the
14 proposed rate adjustments in this case, as initially
15 proposed, customers would pay – and I'm quoting from
16 page 26 of your direct – "rates below the national
17 average." Do you recall that testimony?

18 A [G HARTEY-TAGOE] Yes.

19 Q And now you recognize, however, that the basic
20 facilities charge that your company initially proposed
21 would have been well and above, much higher than the
22 national average; isn't that right?

23 A [G HARTEY-TAGOE] Well, that statement you quoted or
24 referred to refers to the overall rates that the company
25 would be charging customers if its request were

1 approved, not just the basic facilities –

2 Q That's –

3 A [GHARTEY-TAGOE] – charge.

4 Q – right, but I'm asking that you are aware that
5 segmenting out the basic facilities charge as a
6 component of a residential customer's bill, that the
7 initially proposed basic facilities charge would have
8 been the highest in the country for an investor-owned
9 utility?

10 A [GHARTEY-TAGOE] I have seen that in some of the press
11 that your organization has put out, but I have not done
12 a complete survey of every investor-owned utility.

13 Q Have you –

14 A [GHARTEY-TAGOE] I am aware that there are cooperatives
15 in this State that charge close to that. There are
16 municipalities, I'm sure around not only this State, but
17 others that may charge as much as that.

18 Q But you're not proposing that Duke Energy Carolinas
19 become a member-owned cooperative.

20 A [GHARTEY-TAGOE] I am not, but their customers use
21 electricity –

22 Q Sure.

23 A [GHARTEY-TAGOE] – too, so –

24 Q So –

25 A [GHARTEY-TAGOE] – I'm not sure what the point of that

1 is.

2 Q Well, the point is that you believe it's relevant
3 information for this Commission to consider national
4 averages, and Mr. Barnes, in his testimony for Vote
5 Solar, indicated that the national average allowed for
6 increases in basic facilities charge approved by public
7 utility commissions around the country for investor-
8 owned utilities is about a 13.5 percent increase. Did
9 you read his testimony to that effect?

10 A [GHARTEY-TAGOE] I did.

11 Q And that would mean that the new proposed basic
12 facilities charge, as of yesterday, this \$11.96
13 increase, which is a 44 percent increase, would in
14 percentage terms be three times higher than recently
15 approved under the national – national average.

16 A [GHARTEY-TAGOE] That's the way the math works, yes.

17 Q Okay. Moving along. In your rebuttal testimony, you
18 said that an issue of great concern to you is the
19 apparent misunderstanding regarding the company's basic
20 facilities charge. This was on page nine of your
21 rebuttal.

22 A [GHARTEY-TAGOE] Yes.

23 Q And continuing, you testify the parties seem to assume
24 that this change in the basic facilities charge is
25 additive. Do you recall that?

1 A [GHARTEY-TAGOE] Yes.

2 Q And did you also read, in preparation for this hearing,
3 the testimony of Mr. Jonathan Wallach?

4 A [GHARTEY-TAGOE] I think I read a summary of it, yes.

5 Q And, again, either I could – if I can [indicating] – oh,
6 yes, it's on. Good. If I could turn your attention to
7 page 24 of Mr. Wallach's testimony. Do you have a –

8 MS. H. SMITH: Did counsel bring a copy of
9 that for the witness?

10 MR. NEAL: Yes. If he has it, that's great.
11 I'm happy to bring –

12 WITNESS GHARTEY-TAGOE: I do not have it.

13 MR. NEAL: If I may approach?

14 CHAIRMAN RANDALL: [Nodding head.]

15 MR. NEAL: [Indicating.]

16 WITNESS GHARTEY-TAGOE: [Indicating.]

17 BY MR. NEAL:

18 Q Just directing your attention to page 24, lines 22
19 through 24, do you see that Mr. Wallach testified, "With
20 a fixed amount of revenue requirements to be recovered
21 from the Residential class, the higher the Residential
22 BFC, the lower the volumetric energy rate, and vice
23 versa"?

24 A [GHARTEY-TAGOE] I see that, yes.

25 Q So you would agree that Mr. Wallach understands that

1 there is a relationship between the BFC and the
2 volumetric rate, and that it's not just additive; isn't
3 that right?

4 **A** [G HARTEY-TAGOE] That's right.

5 **Q** Can you point to something else in Mr. Wallach's or Mr.
6 Howat's testimony that would indicate that they assume
7 that the change is additive?

8 **A** [G HARTEY-TAGOE] Not sitting here right now.

9 **Q** I can skip some things that were already covered. Now,
10 on page 24 of your direct testimony, you cited a
11 resolution adopted by the National Association of State
12 Utility Consumer Advocates, or NASUCA, in support of the
13 company's proposal to eliminate credit card fees. Do
14 you recall that?

15 **A** [G HARTEY-TAGOE] Yes.

16 **Q** And I take it that you would not have submitted a
17 resolution from NASUCA in support of your proposal if
18 you didn't generally think that NASACU is a reputable
19 and credible organization; isn't that right?

20 **A** [G HARTEY-TAGOE] That's correct.

21 **Q** And you would agree that the National Association of
22 State Utility Consumer Advocates is to ensure access to
23 least-cost electric utility services for customers?

24 **A** [G HARTEY-TAGOE] I'd agree with that. But to be clear,
25 I'm not -- by citing it, I'm not suggesting I agree with

1 everything NASUCA says.

2 **Q** Sure, but were you aware that NASUCA also adopted a
3 resolution against electric utility efforts to increase
4 fixed charges?

5 **A** [GHARTEY-TAGOE] I'm not aware of that.

6 **MR. NEAL:** If I could at this time have an
7 exhibit marked? I assume we're at 13?

8 [Document distributed]

9 **CHAIRMAN RANDALL:** Do you have one for the
10 Commissioners?

11 **MR. NEAL:** Oh, yes. Sorry. My apologies.

12 **CHAIRMAN RANDALL:** We might mark it, then.

13 **MR. NEAL:** Yes [indicating].

14 [Laughter]

15 **CHAIRMAN RANDALL:** That'll be marked as
16 Hearing Exhibit 13.

17 [WHEREUPON, Hearing Exhibit No. 13 was
18 marked for identification.]

19 **MR. NEAL:** Apologies. Pro hac vice coming
20 through.

21 **BY MR. NEAL:**

22 **Q** Mr. Gharthey-Tagoe, I've handed out what has been marked
23 as Hearing Exhibit 13, which is the NASUCA Customer
24 Charge Resolution from 2015. It's titled 2015-1
25 "Opposing Gas and Electric Utility Efforts to Increase

1 Delivery Service Customer Charges." Now, again, drawing
2 your attention to what's been marked as Hearing Exhibit
3 13, I take it that you haven't previously read this
4 resolution before?

5 **A** [G HARTEY-TAGOE] I have not.

6 **Q** To try to speed things along, I've highlighted some
7 provisions. If you turn to the very last page, I think
8 what should be the final highlighted section, the "Be it
9 further resolved..."? Do you see where it reads, "Be it
10 further resolved that NASUCA urges state public service
11 commissions to reject gas and electric utility rate-
12 design proposals that seek to substantially increase the
13 percentage of revenues recovered through the flat
14 monthly customer charges on residential customer utility
15 bills, proposals that disproportionately and inequitably
16 increase the rates of low-usage customers; a group that
17 often includes low-income, elderly, and minority
18 customers throughout the United States." Do you see
19 that?

20 **A** [G HARTEY-TAGOE] I do.

21 **Q** And to speed things along, I won't have you read through
22 the other highlighted portions. But you recognize that
23 NASUCA's position is consistent with the position of my
24 clients in this case?

25 **A** [G HARTEY-TAGOE] I do.

1 **Q** All right. In this docket, Mr. Gharthey-Tagoe, Duke
2 Energy Carolinas has not made any commitment of
3 shareholder funds, or otherwise, to benefit low-income
4 ratepayers that would maybe mitigate impacts from its
5 proposed rate adjustments; is that right?

6 **A** [GHARTEY-TAGOE] We have not.

7 **Q** Can you commit to the company doing so?

8 **A** [GHARTEY-TAGOE] No, I cannot. But I will assure – I
9 mean, we provide funds for Share the Warmth. That
10 funding comes from both customers, our employees; our
11 foundation puts money into that, as well. So that's
12 available, and often goes to lower-income customers who
13 have challenges paying their bills.

14 **MR. NEAL:** Thank you. I have no further
15 questions.

16 Oh, at this time, I would move to admit
17 Hearing Exhibit 13?

18 **CHAIRMAN RANDALL:** Hearing Exhibit 13 will be
19 admitted into the record.

20 [WHEREUPON, Hearing Exhibit No. 13 was
21 received in evidence.]

22 Okay. Sierra Club.

23 **MS. LEE:** Good morning, Mr. Chairman,
24 Commissioners, Hearing Officer Dong, and Ms. Wheat.
25 My name is Bridget Lee, from the Sierra Club.

CROSS EXAMINATION

BY MS. LEE:

Q Good morning, Mr. Gharthey-Tagoe and Ms. Smith. I believe most of my questions will be directed to you, Mr. Gharthey-Tagoe.

I'm going to switch gears a little bit from the previous questioners. Your testimony addressed impacts of the company's requested rate adjustment to customers, and specifically you explain the impact to the typical residential customer. Is that right?

A [GHARTEY-TAGOE] Yes.

Q Of those impacts, the requested increase in rates, do you know what percentage is attributable to the coal-ash cleanup costs that are requested for recovery?

A [GHARTEY-TAGOE] Not sitting here now, but Ms. Smith might be able to help with that.

Q Ms. Smith?

A [K. SMITH] And I do not have the percentage increase, but it is one of the larger increases.

Q Okay, thank you. More than — is it more than half, do you know?

A [K. SMITH] I would say more like a fourth, between —

Q Okay.

A [K. SMITH] Yes.

Q And Mr. Gharthey-Tagoe, you also testified that the

1 company expects to continue to invest significant
2 amounts related to coal-ash compliance after the
3 December 2018 cutoff in this case; is that right?

4 A [GHARTEY-TAGOE] That's correct.

5 Q And of those future costs, has the company estimated
6 what the total might be?

7 A [GHARTEY-TAGOE] I believe Mr. Kerin can answer. We do
8 have some estimates.

9 Q Okay. And do you know, or would Mr. Kerin be the
10 witness to ask, if there's an estimate about how long
11 coal-ash pond closure and groundwater contamination
12 might take?

13 A [GHARTEY-TAGOE] Mr. Kerin –

14 Q Okay.

15 A [GHARTEY-TAGOE] – could probably answer that.

16 Q I'm skipping these questions that I can ask Mr. Kerin
17 instead. And I have a few more, but if you want to
18 defer these to Mr. Kerin, just let me know. So, the
19 current estimates for the cleanup of coal ash, is it
20 right that those are based on the assumption that many
21 of the company's ponds will be capped in place?

22 A [GHARTEY-TAGOE] Some – I know some will be capped in
23 place. I don't know what you mean by "many." But, yes,
24 some will –

25 Q Some are –

1 A [GHARTEY-TAGOE] — be capped, some —
2 Q — are being excavated.
3 A [GHARTEY-TAGOE] — are being excavated.
4 Q Sure.
5 A [GHARTEY-TAGOE] So —
6 Q There's a mix there.
7 A [GHARTEY-TAGOE] There is a mix.
8 Q And so, if the EPA or the North Carolina Department of
9 Environmental Quality or a court required excavation of
10 all the ponds, is it your understanding that the total
11 cost would be higher than what the estimate now is?
12 A [GHARTEY-TAGOE] Absolutely.
13 Q Okay.
14 A [GHARTEY-TAGOE] I will say, in South Carolina, through a
15 consent agreement with the Department of Health and
16 Environmental Control, we have and are excavating the
17 two basins we have in South Carolina.
18 Q Thank you. And in your testimony, you mentioned that
19 the company is not seeking recovery of any fines or
20 penalties incurred related to coal-ash management. Is
21 that correct?
22 A [GHARTEY-TAGOE] Yes.
23 Q But is the company seeking costs related to the cleanup
24 of the Dan River spill, aside from fines?
25 A [GHARTEY-TAGOE] No.

1 Q Okay. How about with respect to the closure of the
2 ponds at Dan River?

3 A [GHARTEY-TAGOE] Yes, we are.

4 Q And you've testified that the company has followed
5 industry practices in storing its coal ash and has done
6 so consistent with regulations, correct?

7 A [GHARTEY-TAGOE] Correct.

8 Q Okay. Are you familiar with the North Carolina 02L
9 groundwater standards that took effect in 1979?

10 A [GHARTEY-TAGOE] No, ma'am.

11 Q Okay. As a former senior VP for state and federal
12 regulatory legal support, are you familiar with the
13 Clean Water Act?

14 A [GHARTEY-TAGOE] Yes, I am.

15 Q And its implementing regulations?

16 A [GHARTEY-TAGOE] Well, I know they have —

17 Q In a general sense.

18 A [GHARTEY-TAGOE] — many — yes, in a general sense.

19 Q Okay. Are you aware that, in 2015, the company pled
20 guilty to violations of the Clean Water Act and its
21 regulations as part of a criminal investigation
22 following the Dan River spill?

23 A [GHARTEY-TAGOE] I am aware of that, yes.

24 Q And were the violations the company admitted to, were
25 those limited to the Dan River spill, or did they

1 involve other mismanagement at other coal-ash sites?

2 **A** [G HARTEY-TAGOE] They involved a couple of other sites,
3 yes.

4 **Q** Okay.

5 **A** [G HARTEY-TAGOE] I wouldn't call it mismanagement, but it
6 involved incidents at other sites.

7 **Q** So you say you wouldn't call it mismanagement, but isn't
8 it right that the company pled guilty to criminal
9 negligence?

10 **A** [G HARTEY-TAGOE] We did.

11 **Q** So is criminal negligence not mismanagement?

12 **A** [G HARTEY-TAGOE] Well, as you know, the Clean Water Act
13 is a strict liability statute. And there's a joint
14 statement of facts that goes with the plea, and I would
15 refer you to that.

16 **Q** Sure, thanks. Would it be fair to say, given that joint
17 statement of facts, that, at least for Dan River and the
18 other coal-ash sites that are part of that federal case,
19 the company didn't act consistent with regulations 100
20 percent of the time?

21 **A** [G HARTEY-TAGOE] With respect to these incidences, yes.

22 MS. LEE: Okay. That's all I have. Thank
23 you.

24 CHAIRMAN RANDALL: Thank you, Ms. Lee.
25 South Carolina Energy Users.

1 CROSS EXAMINATION

2 BY MR. ELLIOTT:

3 Q If I may, a few questions for Ms. Smith. I wouldn't
4 want you to feel left out.

5 A [K. SMITH] No, I don't want to feel left out.

6 Q Ms. Smith, I'd like you to help me understand, just
7 briefly, what AFUDC is.8 A [K SMITH] That is the interest that's accrued during the
9 construction of a plant to reflect the time value of
10 money, because we are not recovering those costs from
11 our customers at that time.12 Q And so, if I were led to understand by Bill Sandifer,
13 who's the chairman of the LCI Committee, that AFUDC is
14 essentially financing cost, would that be a fair
15 generalization?

16 A [K. SMITH] Yes.

17 Q All right. Now, you are aware that the company is
18 seeking recovery of \$248 million in AFUDC in this case
19 for the Lee nuclear plant.

20 A [K. SMITH] Yes, I am.

21 Q And if I showed you page 27 from Mr. Fallon's
22 testimony –23 MR. ELLIOTT: Could I get a little help up
24 here? I've forgotten since November how to work
25 this thing. How do I –

1 **MS. H. SMITH:** Did you bring a copy for the
2 witness?

3 **MR. ELLIOTT:** Well, I tell you what I can do.
4 I can show her page 27 of Mr. Fallon's testimony.

5 **MS. H. SMITH:** Do you have an entire copy of
6 Mr. Fallon's testimony, so she can read it for
7 context?

8 **MR. ELLIOTT:** Yes, ma'am, she can read the
9 whole thing if she likes, but I don't think she'll
10 need to.

11 [Brief pause]

12 **BY MR. ELLIOTT:**

13 **Q** You will see a chart there, Ms. Smith, of a cost
14 category. I think you would recognize it. I'll note
15 that on lines one and two, Mr. Fallon says, "Company
16 Witness Kim H. Smith describes the rate treatment,
17 including the proposed amortization schedule, in her
18 direct testimony filed in this case." Do you see that
19 line of testimony in this testimony?

20 **A** [K. SMITH] Yes, I do. And I'd also like to correct. I
21 think you asked me if the company was asking to recover
22 \$248 million of AFUDC, but the South Carolina share is
23 only around 24 percent.

24 **Q** Good, thank you.

25 **A** [K. SMITH] Yes.

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1 Q And you are reading my mind. But for these purposes,
2 systemwide, Mr. Fallon's number is correct; 248,
3 correct?

4 A [K. SMITH] Yes, that's correct.

5 Q And in making your calculations in your testimony, you
6 used the 248 number and then reduced it to 24 percent
7 for South Carolina.

8 A [K. SMITH] Yes.

9 Q Good, thanks. And you understand that – because you
10 testify in your testimony – that there've been at least
11 a couple of orders of this Commission that address the
12 cost recovery for Lee nuclear, correct?

13 A [K. SMITH] Yes.

14 Q And one of those orders arose in Docket 2011-20-E, which
15 you cite in your testimony; is that correct?

16 A [K. SMITH] Yes.

17 Q All right. And you understand that the Commission, in
18 Order No. 2011-454, arising out of Docket No. 2011-20-E,
19 had recovery of certain Lee nuclear construction costs.
20 Do you recall that from your review of –

21 MS. H. SMITH: I believe he's asking for a
22 legal conclusion from the witness, and she has
23 testified she is not an attorney.

24 MR. ELLIOTT: Well, I think she's testified to
25 just a factual statement from this order, and I'm

1 happy just to show her the provision of the order
2 that sets out the cap.

3 WITNESS K. SMITH: And what page of my
4 testimony are you referring to?

5 BY MR. ELLIOTT:

6 Q Well, you cite on page 26 of your testimony the – this
7 docket – excuse me. You cite –

8 A [K. SMITH] My direct testimony?

9 Q Yes, ma'am. I'm sorry. Direct. You cite on page 19,
10 if you'll look at line eight, please.

11 A [K. SMITH] Okay.

12 [Brief pause]

13 Q Now, having refreshed your recollection from your
14 testimony, do you recall having read the order in that
15 docket?

16 A [K. SMITH] The Docket 2011-20-E?

17 Q Yes, ma'am.

18 A [K. SMITH] I cannot say that I read the whole order, no.

19 Q All right. Let me draw your attention to page 17 of the
20 order, and there's a paragraph three. And the order
21 reads, "The company must incur only those costs
22 absolutely necessary to keep the Lee nuclear project
23 available as an option in the 2021 timeframe. The
24 prudence determination made in this proceeding applies
25 only to the South Carolina allocable share of the

1 additional preconstruction costs of \$75 million without
2 AFUDC, not to exceed \$120 million with AFUDC, for the
3 period of January 1, 2011, through June 30, 2012." Do
4 you see that language?

5 A [K. SMITH] I do see that language.

6 Q And does that refresh your recollection as to what the
7 Commission ordered?

8 A [K. SMITH] There's also various other dockets during
9 this, so this is – that is what they ordered in that
10 docket, yes.

11 Q Yes, ma'am. And as a part of that order, you would
12 recall that the Commission required Duke to file a
13 quarterly report on expenditures and AFUDC. You recall
14 that, don't you?

15 A [K. SMITH] Yes, we do file quarterly reports.

16 Q All right. And you understand that you would have filed
17 a quarterly report for the period ending June 30, 2012,
18 do you not?

19 A [K. SMITH] Yes, that would be reasonable.

20 Q [Indicating.]

21 A [Indicating.]

22 Q Now, Ms. Smith, I've shown you a document labeled
23 "Before the Public Service Commission of South
24 Carolina," Docket No. 2011-20-E. Do you see that
25 document?

1 A [K. SMITH] Yes, I do.

2 Q Have you had a chance to take a look at it?

3 A [K. SMITH] If I could take a moment, please.

4 Q Please, feel free.

5 A [K. SMITH] Okay.

6 [Brief pause]

7 Q Let me draw your attention – let me draw your attention
8 to the second page of that document filed with the
9 Public Service Commission, and draw your attention to
10 the next-to-the-bottom line that reads "AFUDC." Do you
11 see that on the far left?

12 A [K. SMITH] Yes, I do.

13 Q And if I correctly understand the document, immediately
14 to the right of that acronym "AFUDC" is the number
15 roughly \$23.7 million. Do you see that?

16 A [K. SMITH] I do see that.

17 Q And according to the Duke filing, that would be the
18 AFUDC accumulated for the period 1/1/2011 through
19 12/31/2012. Would that be correct?

20 A [K. SMITH] Actually, it says at 3/31/2012.

21 Q Thank you, 3/31. And to the right of that number is a
22 number of about \$5.5 million, correct?

23 A [K. SMITH] Yes.

24 Q And correct me if I'm wrong; that number represents the
25 quarterly AFUDC for the period 4/1/2012 through

1 6/30/2012, correct?

2 A [K. SMITH] Yes.

3 Q All right. And continuing to the right, there's a

4 number, \$29,201,000? Do you see that?

5 A [K. SMITH] Yes, that's correct.

6 Q And that's the total for the period 1/1/2011 through

7 6/30/2012. Do you see that?

8 A [K. SMITH] Yes, I do.

9 Q And would you disagree with me if I suggest to you that

10 that number is the amount of the AFUDC accumulated

11 pursuant to Order No. 2011-454 in Docket No. 2011-20-E?

12 Would you disagree with my statement?

13 A [K. SMITH] The one paragraph you showed me, yes.

14 Q All right. And then the last number of AFUDC is roughly

15 \$68 million. Do you see that?

16 A [K. SMITH] Yes.

17 Q And that's the total AFUDC from the inception of the Lee

18 nuclear project to 6/30/2012, correct?

19 A [K. SMITH] Yes.

20 Q All right. Now, drawing your attention back to Mr.

21 Fallon's testimony and his chart, from the period –

22 systemwide – from the period 6/30/2012 through roughly

23 the date of this hearing, the AFUDC accumulated from

24 about \$68 million to \$248 million, systemwide, correct?

25 A [K. SMITH] Yes, that is true. And we stopped AFUDC on

1 12/31/2017.

2 Q Good, thank you. So that \$248 million number is through
3 12/31/2017?

4 A [K. SMITH] Yes.

5 Q So it would've accumulated from July 1, 2012, through
6 the 2017 date, correct?

7 A [K. SMITH] Yes, sir.

8 Q Now, you understand that, pursuant to Order No. 2011-
9 454, at least the consequence of that order was that
10 Duke was authorized systemwide to recover about \$350
11 million in preconstruction costs associated with the Lee
12 nuclear plant, correct?

13 MS. H. SMITH: I think we're getting into a
14 legal conclusion again. I mean, we're not
15 objecting to what the order said; it can speak for
16 itself. But what the legal conclusion is is beyond
17 the scope of this witness.

18 CHAIRMAN RANDALL: The order will speak for
19 itself.

20 MR. ELLIOTT: Very fine. Thank you.

21 BY MR. ELLIOTT:

22 Q And, but you do understand that from the period of the
23 inception of the Lee nuclear plant through 6/30/2012,
24 whatever you were authorized, Duke only spent about \$251
25 million in preconstruction costs. You understand that

1 to be the case, don't you?

2 A [K. SMITH] And that is listed on here [indicating],

3 correct?

4 Q That would not be listed on there, no, ma'am. I just –

5 I thought, since you were the rates woman –

6 A [K. SMITH] Well –

7 Q – you would know that. The rates witness.

8 A [K. SMITH] – that – and that was, what, 2012, so that's

9 – I don't know it by year on how much we've spent.

10 Q All right.

11 A [K. SMITH] I mean, it's –

12 Q That's fine. Let me understand, from your testimony,

13 please, and I'd draw your attention, if I may, to pages

14 19 and 20 of your direct.

15 A [K. SMITH] [Indicating.]

16 Q As I understand it, Duke is seeking to recover \$518

17 million, total, from the Lee nuclear preconstruction

18 costs? Am I correct? I have a little confusion, so –

19 A [K. SMITH] We're asking for recovery of \$125 million.

20 Q All right. For South Carolina?

21 A [K. SMITH] Yes.

22 Q And what, systemwide?

23 A [K. SMITH] The systemwide is approximately four times

24 that.

25 Q Okay. The reason I ask is, in Mr. Fallon's chart, it

1 shows a total preconstruction cost of \$559 million. Do
2 you see that?

3 A [K. SMITH] Yes, I do.

4 Q And I think I understand that some of the land and
5 right-of-way costs may not be recoverable pursuant to
6 preconstruction costs, that there's some aspect of that
7 that doesn't go into rate base and that, as a
8 consequence, the total system number is \$518 million.
9 Am I —

10 A [K. SMITH] Yeah, we have removed the land held for
11 future use and put it in rate base, plus we removed the
12 cost related to the visitors' center.

13 Q Good. And so, with that — with that — would that reduce
14 the total on Mr. Fallon's chart from 559 to 518?

15 A [K. SMITH] Let me check my — it's in my pro forma. But,
16 yes, it is approximately correct.

17 Q Okay. That's all I'm asking.

18 A [K. SMITH] Okay.

19 Q I'm just trying to make sure I have it straight. Now,
20 directly to your testimony, on page 19, at line 20, this
21 is where you introduce to the Commission the \$125
22 million Lee nuclear preconstruction-cost ask for South
23 Carolina.

24 A [K. SMITH] Yes.

25 Q And then your testimony goes on to say that the annual

1 revenue requirement in this proceeding is \$20 million.

2 Am I correct?

3 A [K. SMITH] That is true.

4 Q Now, if the total Lee nuclear preconstruction costs are
5 roughly 518, then it's fair to say that almost half of
6 that total cost is the AFUDC you're seeking recovery of;
7 is that correct?

8 A [K. SMITH] That is true, yes.

9 Q And so if you're seeking \$20 million here, and of the
10 \$20 million I think \$11 million are the capital costs –
11 as the Base Load Review Act would call them – of the
12 preconstruction costs that you're seeking recovery of,
13 correct?

14 A [K. SMITH] Yes.

15 Q All right. So you're asking for 20; 11 are the capital
16 costs. And so, of the \$11 million a year you're asking
17 the customers to pay, about half of that number would be
18 the financing cost over the 12-year life of the project,
19 correct?

20 A [K. SMITH] Correct.

21 Q Now, turning to page 20, as I understand it, the balance
22 of the \$20 million annual cost, or the \$9 million, is
23 the net-of-tax return on the amount you're seeking
24 recovery of. Is that correct?

25 A [K. SMITH] Excuse me, can you ask that again?

1 Q Well, I – it was a bad question, but if you'll look at
2 the bottom of page 19, top of page 20.

3 A [K. SMITH] All right.

4 Q I'm doing no more than simply asking, very inartfully,
5 for you to say what you said much more artfully on those
6 lines. Basically, \$11 million of the 20 are the capital
7 costs, and \$9 million is the return?

8 A [K. SMITH] That is true, yes.

9 Q And of that return, that's not pure profit to Duke, is
10 it?

11 A [K. SMITH] No, it is not pure profit.

12 Q Wouldn't it be fair to say that approximately \$6 million
13 of that, based on your capital structure, would be what
14 at least your ratepayers would consider profit?

15 A [K. SMITH] No, I do not agree with that.

16 Q Well, how much is profit?

17 A [K. SMITH] It is not profit. The – we are not currently
18 recovering these costs in rates –

19 Q Right.

20 A [K. SMITH] – from our customers. So, since we're not
21 recovering these costs and we have incurred these costs,
22 these costs are being advanced by our investors, our
23 debt and equity investors. And so it is a cost we have
24 incurred, and the shareholders and debt investors have
25 advanced these costs to the company to incur, and so it

1 is a – when they advance costs to us, they expect a
2 return.

3 Q All right.

4 A [K. SMITH] So it's not a profit.

5 Q Would it be fair to say that, of the \$9 million, about
6 \$3 million is associated with debt?

7 A [K. SMITH] Yes, probably – yeah.

8 Q And would it be fair to say, then, that, of the \$9
9 million, \$6 million is associated with equity?

10 A [K. SMITH] Yes.

11 MR. ELLIOTT: Mr. Chairman, thank you. I have
12 no further questions.

13 CHAIRMAN RANDALL: Thank you.
14 Walmart.

15 MS. GRUNDMANN: Good morning. My name is
16 Carrie Grundmann, here on behalf of Walmart.

17 CROSS EXAMINATION

18 BY MS. GRUNDMANN:

19 Q My questions are for Mr. Gharthey-Tagoe, and –

20 CHAIRMAN RANDALL: Is your microphone on? I
21 just want to make sure. Is that red light on?

22 MS. GRUNDMANN: [Indicating.] I will speak
23 closer to it.

24 CHAIRMAN RANDALL: There you go. You can bend
25 it towards you.

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1 BY MS. GRUNDMANN:

2 Q Mr. Gharthey-Tagoe, my questions relate primarily to a
3 sentence that was contained in your opening statement
4 this morning. I'll read it aloud, so that we're both
5 talking about the same thing, but it's the underlined
6 sentence that says, "We have shown that the company's
7 proposed return on equity is in line with other ROEs
8 determined by other regulatory commissions in the
9 Southeast."

10 I'd like to understand what you are relying on when
11 you make that sentence — the conclusion in that
12 sentence?

13 A [GHARTEY-TAGOE] I would refer you to the testimonies of
14 Jack Sullivan, as well as Mr. Hevert. They both refer —
15 I believe Jack Sullivan's contains the table in there,
16 showing commission decisions from various states in the
17 Southeast. It includes Mississippi, it includes
18 Florida, it includes South Carolina and North Carolina.
19 And I believe, since 2013 until now, a range of about
20 9.85 percent to, I think it's been 10.5, or so, has been
21 approved by commissions, with an average of about 10.19
22 percent. That's what I'm relying on.

23 Q Is this [indicating] the chart to which you were just
24 referring?

25 A [GHARTEY-TAGOE] Yes.

1 Q And in looking at this chart, would you agree with me
2 that, if we accept every one of the returns listed
3 there, that the average of those returns is 10.19
4 percent?

5 A [GHARTEY-TAGOE] Yes.

6 Q And that is actually one basis point below your
7 currently authorized return, yes?

8 A [GHARTEY-TAGOE] Correct.

9 Q And 31 points below the return that you proposed in
10 these proceedings?

11 A [GHARTEY-TAGOE] Yes.

12 Q And I want to direct your attention to the two entries
13 listed there from 2018, in your proceedings before the
14 North Carolina Commission. You recognize that you all
15 were awarded a 9.9 percent ROE in the North Carolina
16 proceedings, yes?

17 A [GHARTEY-TAGOE] Agreed. We settled on that, and the
18 Commission approved the settlement.

19 Q Do you believe that the 10.5 percent ROE proposed in
20 these proceedings is, as you described in your opening
21 statement, in line with the ROE awarded in North
22 Carolina?

23 A [GHARTEY-TAGOE] Well, that's not what I said there. I
24 said by commissions in the Southeast.

25 Q Which would include the decisions in North Carolina; is

1 that --

2 **A** [G HARTEY-TAGOE] Exactly.

3 **Q** That were awarded most recently, last year?

4 **A** [G HARTEY-TAGOE] Yes.

5 **Q** And I think that you told me a minute ago that you base
6 this sentence not only on the testimony from Mr.
7 Sullivan in the chart that we just looked at, but that
8 we also looked at -- that you also based that upon
9 testimony from your expert witness Mr. Hevert; is that
10 correct?

11 **A** [G HARTEY-TAGOE] That's correct.

12 **Q** And you understand that in making his analysis, Mr.
13 Hevert selected a proxy group of companies, are you
14 aware?

15 **A** [G HARTEY-TAGOE] I am.

16 **Q** And do you have any understanding, as we sit here today,
17 as to whether any of those companies in his proxy group
18 of companies were located in the southeastern part of
19 the United States?

20 **A** [G HARTEY-TAGOE] I don't recall the specifics of that.
21 I'm sure he'll be able to tell you.

22 **Q** [Indicating.]

23 **A** [G HARTEY-TAGOE] Yes.

24 **Q** Would you just take a look through that list of proxy
25 group companies and identify for me whether any of those

1 companies are located within the southeastern portion of
2 the United States?

3 A [GHARTEY-TAGOE] I'd say third from the bottom, Southern
4 Company; that is in the southeastern part of the US.
5 They're headquartered in Atlanta, Georgia, I believe.
6 That is in the Southeast.

7 Q Any other companies?

8 A [GHARTEY-TAGOE] NextEra Energy would be from Florida.

9 Q Any other company?

10 A [GHARTEY-TAGOE] AEP is in Virginia.

11 Q AEP was not among the Southeastern companies that were
12 identified by Mr. Sullivan, were they?

13 A [GHARTEY-TAGOE] No.

14 Q And, actually, AEP Company, Inc., is the parent company
15 of the APCO Virginia entity; isn't that correct?

16 A [GHARTEY-TAGOE] That's correct.

17 Q That would include their operations in West Virginia,
18 Ohio, Kentucky, among others?

19 A [GHARTEY-TAGOE] That's correct.

20 Q So, in terms of your testimony in this proceeding as to
21 the ROE, you undertook no effort to ensure that Mr.
22 Hevert's proxy group analysis incorporated returns for
23 Southeastern utilities. Isn't that fair?

24 A [GHARTEY-TAGOE] Well, I think the chart you just
25 displayed shows a number of Southeastern companies.

1 That's his proxy group.

2 Q This [indicating] is the proxy – this is the proxy
3 group, correct?

4 A [GHARTEY-TAGOE] Correct.

5 Q Of the companies identified in the southeastern US here
6 by Mr. Sullivan, were any of these included in Mr.
7 Hevert's proxy group?

8 A [GHARTEY-TAGOE] So, Georgia Power is associated with
9 Southern Company.

10 Q Okay.

11 A [GHARTEY-TAGOE] That's the first one listed. Florida
12 Power & Light is a subsidiary of NextEra, which was in
13 the proxy group listing.

14 Q Any other company?

15 A [GHARTEY-TAGOE] I believe Gulf Power is now owned by
16 NextEra. And I think that would be it.

17 Q Based upon your opening statement and your testimony on
18 ROE, and the testimony from your Witnesses Mr. Hevert
19 and Mr. Sullivan, are you asking this Commission to
20 accept the 10.5 percent from Mr. Hevert or are you
21 asking this Commission to look at the average ROE for
22 utilities in the Southeast when determining what an
23 appropriate ROE in these proceedings would be?

24 A [GHARTEY-TAGOE] We're asking the Commission, based on
25 the expert testimony of Mr. Hevert, to accept the 10.5

1 percent. His testimony supports 10.75 percent. In an
2 effort to moderate the ask or the increase that we
3 requested in this case, we built the case on 10.5
4 percent, and that's what we're asking the Commission to
5 accept,

6 **Q** And you feel comfortable that, since your last rate
7 case, circumstances have changed sufficiently that at
8 least a 31 percent increase in your return on equity is
9 justified here?

10 **A** [G HARTEY-TAGOE] I believe the testimony we filed in
11 North Carolina supported a similar – a similar ask.
12 And, yes, we believe that's justified.

13 **Q** And as you make that statement, do you factor in, at all
14 – I have pulled here page 15 of the rebuttal testimony
15 of Mr. Hevert, but I think similar numbers were set
16 forth in the testimony from Walmart Witness Greg
17 Tillman, regarding average ROEs awarded within the
18 United States. And I believe Mr. Hevert's testimony
19 here summarizes it fairly, but I think the numbers we
20 see ranged somewhere below 9.8 percent for any year,
21 going back as far as 2014. Would you agree with that?

22 **A** [G HARTEY-TAGOE] That's what I see on that page, yes.
23 But again, when it comes to the – and Mr. Hevert will be
24 able to explain this in great detail, but when it comes
25 to the determination of a return on equity, it's not a

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1 question of just taking averages. There are various
2 methodologies that are used. Some witnesses use the
3 CAP-M method, and so forth. And he supports what we've
4 asked for in great detail, and I would encourage you to
5 ask him those questions.

6 **Q** Oh, I absolutely intend to ask Mr. Hevert questions. I
7 simply am attempting to understand upon what you based
8 your conclusion in your opening statement that the
9 company's ROE is consistent with the ROEs by other
10 regulatory commissions in the Southeast, when the data
11 I'm looking at shows a 10.19 percent ROE.

12 **A** [GHARTEY-TAGOE] Okay.

13 **MS. GRUNDMANN:** I don't have any other
14 questions.

15 **CHAIRMAN RANDALL:** Thank you.

16 We're going to take a short break. When we
17 come back, we'll continue with ORS and
18 Commissioners. We'll break for lunch about 12:30.
19 And then, after we come back from lunch, we will
20 finish at 4:30 this afternoon. Just wanted to let
21 y'all know my schedule. So, with that, we'll take
22 a short break. Thank you.

23 [WHEREUPON, a recess was taken from 11:35
24 to 11:49 a.m.]

25 **CHAIRMAN RANDALL:** Okay. I was asked -- we'll

1 start tomorrow at 10 o'clock. What we originally
2 planned was we'd see how far we get tomorrow, and
3 by tomorrow afternoon we'll make a decision on the
4 first part of next week, if we need to start a
5 little sooner, or what. Sort of depends on you.

6 [Laughter]

7 So, ORS.

8 MR. NELSON: Thank you, Mr. Chairman.

9 CROSS EXAMINATION

10 BY MR. NELSON:

11 Q Mr. Gharthey-Tagoe, I'm going to start with you, and, Ms.
12 Smith, I promise I won't leave you out.

13 A [K. SMITH] I'm sure you won't.

14 Q Mr. Gharthey-Tagoe, as part of your function as the
15 President of the South Carolina – Duke South Carolina,
16 you attended the night hearings in this case; isn't that
17 correct?

18 A [GHARTEY-TAGOE] I did.

19 Q Okay. And I'm sure you heard the comments from a lot of
20 the ratepayers who we heard – I think over 150 people
21 spoke – that some of them are having a difficult time
22 being able to pay the current rates, let alone looking
23 at an increase, right?

24 A [GHARTEY-TAGOE] I agree, I heard that.

25 Q But at the same time, Duke is still – you are still

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1 asking in this case for customers to pay for items such
2 as team lunches, decorations for office celebrations,
3 and employee coffee. Isn't that true?

4 A [GHARTEY-TAGOE] Yes.

5 Q Okay. Do you think that it's fair that you continue to
6 – that these people that can't afford their bills now
7 pay for coffee for your employees?

8 A [GHARTEY-TAGOE] I think it's important that customers –
9 we compete for talent, much like any other company. And
10 to provide cost-effective, reliable, safe electricity,
11 you need qualified, very good employees. And so
12 sometimes we spend money on things that include things
13 that improve employee engagement, things that increase
14 effectiveness of employees. Those are some of the costs
15 you're referring to here, and I think it's important to
16 provide some of these things, because when employees can
17 get something better down the road, they will go down
18 the road. So we have to be competitive in the
19 marketplace for talent.

20 Q Well, you kind of have an option on these things as to
21 whether the ratepayers pay for it or whether the
22 shareholders pay for it, right?

23 A [GHARTEY-TAGOE] Certainly, every item – cost item – we
24 have, you could say. But, you know, as you know, the
25 precedent – or, the Supreme Court has said, on the one

1 hand, you're balancing reasonableness of rates, on the
2 other hand, the utility getting a fair return on its
3 investment devoted to the public use.

4 **Q** Has the company considered at all the impact, and
5 especially based on the customer comments about
6 difficulty paying, how this may affect the bad debt or
7 the uncollectibles of the company? Have you considered
8 that?

9 **A** [GHARTEY-TAGOE] I'm not sure I understand the question.

10 **Q** Sure. If so many people are saying they can't afford to
11 pay their power bills, isn't that going to drastically
12 increase, or won't that show an increase in the
13 company's uncollectibles?

14 **A** [GHARTEY-TAGOE] It could, yes.

15 **Q** And then, therefore, that would then be paid by the
16 other customers, correct, the uncollectibles?

17 **A** [GHARTEY-TAGOE] Yes.

18 **Q** Yeah. Does Duke have any kind of a low-income
19 assistance fund to help some of these low-income or
20 elderly customers?

21 **A** [GHARTEY-TAGOE] I mentioned earlier our Share the Warmth
22 program, which includes funding from our foundation. It
23 includes contributions from other customers,
24 contributions from our employees. Those funds typically
25 are distributed to agencies around our service

1 territory. I believe, in the Anderson hearing, we heard
2 from Kristi Brock, who heads up the Anderson Interfaith
3 Ministry, or AIM. And she talked about some of the
4 funding we provide to her agency so that they can, in
5 turn, provide it to customers who are unable to pay
6 their bills, so...

7 Q So you don't do it directly, but you do it indirectly
8 through these other organizations; is that right?

9 A [G HARTEY-TAGOE] Exactly.

10 Q Okay. How long do you think it's going to be before the
11 company comes in to ask for another rate increase?

12 A [G HARTEY-TAGOE] I can't say, sitting here, and I think
13 the outcome of this case could also be a factor.

14 Q Does the change in your position on the base facility
15 charge in some way affect that, that you might be in
16 sooner, with this low base facility charge?

17 A [G HARTEY-TAGOE] I don't believe o.

18 Q We heard a lot of complaints at the night hearings, too,
19 about customer service. And there seemed to be – in
20 particular, there seemed to be a disconnect a lot of
21 times with what people call in with and then who's sent
22 out to do work. Has the company done anything since
23 those night hearings, or have you started a process at
24 all to try to correct those problems that were
25 identified?

1 **A** [G HARTEY-TAGOE] See, and we want – I think the value of
2 the night hearings is to hear – give customers an
3 opportunity to speak to the Commission about their
4 individual situations. I will say, as you said, about
5 150 speakers – we have over 591,000 accounts in the
6 upstate, all right? I will say, some of the – a small
7 fraction of the 150 who spoke raised the issue you just
8 described, in terms of a disconnect between what they
9 called a call center with. And those things can happen.

10 I will tell you, I get letters; I get calls from
11 customers about issues like that, or other issues. And
12 typically the way I handle it is I identify – I've got
13 someone who is dedicated to customer service on my team,
14 who investigates that. And to the extent that there's
15 an operational deficiency, we correct it. To the extent
16 that it was a miscommunication – sometimes that's what
17 it is, a miscommunication between the customer and the
18 call-center representative, and we fix that. So those
19 things do happen, or have happened. And when they do,
20 we fix it.

21 **Q** I want to ask you about the AMI meters, too, because
22 that was another issue that was discussed at length.
23 And we heard from a lot of customers that they actually
24 thought their bills had doubled as a result of these AMI
25 meters being installed. Is that a recurring problem

1 that the company has identified, or can you just address
2 that issue?

3 **A** [G HARTEY-TAGOE] Yes, thank you for the opportunity to
4 address it, because there was one who alleged that his
5 bill had gone from \$400 to \$900. Thankfully, we got his
6 name, we pulled up his record. And in the last 18
7 months, or so, since his meter was installed, there was
8 no bill for \$900 on his record. You know, so sometimes
9 I do think – you know, I think they just want to make
10 their point, and they throw out numbers. But we have
11 not gotten many complaints of bills doubling.

12 I have an AMI meter on my home, and I can assure
13 you my bill has not doubled.

14 **Q** Have you – and I guess as a part of the process of
15 installing these meters all along, was there
16 coordination made or did you check with other electric
17 utilities throughout the country, as far as what impact
18 these meters may have had on their customers' rates?

19 **A** [G HARTEY-TAGOE] We did reach out to other utilities on
20 the process, in terms of how we engage with customers
21 before we roll it out, the continuing education of
22 customers as we roll it out. So, yes, we learned
23 lessons from other utilities when we did this.

24 **Q** I want to talk for a minute about incentive pay and
25 bonuses. Is there – are any of these tied to actual

1 customer service numbers, like J.D. Power numbers?

2 A [GHARTEY-TAGOE] Yes.

3 Q Okay. And what percentage or for whom are those
4 typically tied to?

5 A [GHARTEY-TAGOE] Well, so, I believe every employee has a
6 short-term incentive opportunity, and the opportunity is
7 tied to metrics such as – as you say – customer service,
8 based on J.D. Power scores, such as safety, such as
9 operational excellence, and then earnings-per-share.
10 Yes.

11 Q All right. Thank you, sir. You mentioned – and I
12 forget who asked this question before, but you talked
13 about two excavations in South Carolina of coal ponds,
14 coal ash in ponds; is that correct?

15 A [GHARTEY-TAGOE] That's correct.

16 Q That was due to a DHEC consent order, as opposed to a
17 State law; isn't that correct?

18 A [GHARTEY-TAGOE] Yes, but DHEC is the State agency
19 charged with enforcing environmental regulations and
20 environmental policy of the State.

21 Q Why did the company decided to go to a 10.5 ROE if your
22 expert said you're entitled to a 10.75?

23 A [GHARTEY-TAGOE] Because we thought that, certainly in
24 recognizing some of the issues the employees_[sic], you
25 know, discussed in the public hearing, we wanted to

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1 mitigate what we ask for in this case, and that's one of
2 the ways that we did that.

3 Q You actually asked for that in the Application, though,
4 didn't --

5 A [GHARTEY-TAGOE] Yes.

6 Q -- you, not -- so which was before the night hearings,
7 correct?

8 A [GHARTEY-TAGOE] Exactly, but I'm saying, even before we
9 filed the Application, we were very conscious of the
10 impact of increasing or raising rates on customers.

11 Q So it's not the fact that you feel that 10.75 is out of
12 line with any current ROE orders.

13 A [GHARTEY-TAGOE] No, it's -- I believe 10.75 is justified
14 by the testimony that we supplied in this case.

15 Q Ms. Smith, I'm going to turn to you now, if I could,
16 please. And I want to talk about the deferrals, because
17 that seems to be one of the -- and we've, you know -- one
18 of the bigger issues, I guess, that we've still got out
19 there. Five of these six deferrals, ORS isn't actually
20 contesting the amount of the deferral, but just a return
21 on that deferral; is that correct?

22 A [K. SMITH] That is true.

23 Q Okay. So, and the sixth one is the coal ash, correct?

24 A [K. SMITH] Yes.

25 Q So the issue that we're really talking about here is

1 just that return. And do you have an idea – could you
2 tell me what amount of money we're talking about between
3 the ORS position and the Duke position?

4 A [K. SMITH] About \$68 million.

5 Q Okay. Is it also true that expenses in the deferral
6 balances you're seeking to recover include both
7 operational-related costs and capital-related costs?

8 A [K. SMITH] The costs that we are requesting to recover,
9 I don't break them out into capital-based costs versus
10 operating-expense costs. We're asking to defer costs,
11 and those costs include the return on the capital, the
12 property taxes, O&M, and depreciation. So, normally
13 interest-expense return is also an operating expense.
14 And all four of those cost categories we're asking to
15 recover are all related to the capital or to the, you
16 know, to the capital project, or the capital, as you all
17 say it. So I don't – we don't normally think of that,
18 breaking it out into capital related and O&M related,
19 but I would think they're all related to the capital.
20 We wouldn't have the property expense if we didn't have
21 the capital.

22 Q But like your O&M expenses you just mentioned, those
23 operational and maintenance expenses are operating
24 expenses, aren't they? That's typical operating expense
25 for the company.

1 A [K. SMITH] So is interest expense. Yes, sir.

2 Q Under what accounting principle or theory is Duke making
3 the claim that they're entitled to a return on a
4 deferral of operating costs?

5 A [K. SMITH] Deferrals on – deferrals are a regulatory
6 mechanism. And we come to the Commission and ask for a
7 deferral when we are incurring costs that we are not
8 currently recovering from our customers. That's why we
9 come and ask for a deferral. And by definition, if we
10 are not recovering those costs from our customers during
11 that time period, then our investors – debt and equity
12 investors – are advancing those funds to the company.
13 And normally, when an investor advances funds to a
14 company, they expect a reasonable rate of return.

15 So, that's what we're asking for, is a reasonable
16 rate of return on these deferrals.

17 Q But, typically, when this Commission and when other
18 commissions set rates – and we go on a historical test
19 year, correct?

20 A [K. SMITH] Yes.

21 Q And so operational and maintenance costs just captured
22 during that test year, except for extraordinary
23 expenses, are what is included in the calculation of
24 rates, right?

25 A [K. SMITH] Yes, there are some adjustments.

1 Q There are some adjustments, I agree, but generally we're
2 talking about just actual O&M expenses during the test
3 year, correct?

4 A [K. SMITH] With some adjustments, that's –

5 Q Okay.

6 A [K. SMITH] – right.

7 Q Coal-ash costs, what – coal-ash costs seem to be
8 extraordinary. I mean, obviously, what you're doing
9 here isn't typical or what's been done in the past, but
10 of the other five of the six deferrals, can you say that
11 there's anything extraordinary about those costs or are
12 those just normal costs of doing business for Duke?

13 A [K. SMITH] They were costs that we were not currently
14 incurring from our customers. And the word
15 "extraordinary," I cannot – I am not sure where that
16 came from, with the – in the context of deferrals, so...

17 Q The company determines when it files a rate case,
18 correct?

19 A [K. SMITH] Yes, it does.

20 Q Okay. And you also – the company also has the option
21 and it's their choice to pick a particular test year,
22 too, correct?

23 A [K. SMITH] Yes.

24 Q So, you also – Duke also appears to be claiming in this
25 case, then, that you're permitted to not only charge

1 ratepayers for non-test-year expenses, but also to earn
2 a return on those expenses. You've got the test year –
3 2017, in this case, right?

4 A [K. SMITH] Yes, we did.

5 Q You're throwing these other costs in, and you want to
6 get a return on that. You don't get a return on the O&M
7 costs during the test year, do you?

8 A [K. SMITH] It's – we're not – well, let me go back. So,
9 a deferral is one mechanism in a wide range of
10 mechanisms for a commission to allow a company to earn
11 its operating expenses plus a reasonable return for its
12 investors. Yes, we do use a test year, which we do
13 update. But in – so, but the deferral helps us – and we
14 do delay rate cases with regard to deferrals. But some
15 states use other mechanisms. Like, so, if you're in a
16 state that allows step-up rates, you may not need
17 deferrals as often. Or if you're in a state that uses a
18 projected test period and not a historical test period,
19 then you can – you may not come in for deferrals as
20 often.

21 But when you have a historical test period that's
22 only adjusted for a certain amount, you can only adjust
23 it a certain amount, then there are costs, since we are
24 not recovering it from our customers, and we think
25 they're prudent costs to incur at that time, then the

1 investors advance us that money. So it's not as much
2 the fact that those costs are not in our test year; it's
3 just investors have advanced us cash, and we are asking
4 for a return on the cash that the investors have
5 invested in the company.

6 **Q** In this whole process, I've heard a lot of times y'all
7 talking about the fact that this all helps your
8 investors; investors expect a return. Isn't this
9 Commission supposed to balance both the interests of the
10 investor, as well as the interests of the ratepayer?

11 **A** [K. SMITH] Well, yes, but the — it's a reasonable
12 return. And, currently, we don't have a reasonable
13 return. And, actually, the ORS Witness Parcell says a
14 reasonable return is 9.3 percent. And so, in our — and
15 our Witness Hevert is 10.75 percent. So unless the
16 investors are earning that return currently, they're not
17 earning a reasonable return, I mean, our — ORS' witness
18 nor DEC's witness.

19 **Q** But ORS isn't contesting the fact that you're entitled
20 to the amount in those deferrals, again, are we? We're
21 only contesting whether or not you're entitled to a
22 return to your investors on those deferrals, correct?

23 **A** [K. SMITH] Okay. But let's look at it this way: It's
24 like when you go to the bank. You go to the bank;
25 you're going to build a new building for your business.

1 And it's going to — if it's needed, it's prudently
2 spent. You've got to serve your customers and you need
3 a new building. So you go to the bank and you're like,
4 "Oh, I need to borrow some money on a construction loan;
5 I'm going to build a new store, some inventory, et
6 cetera, hire employees. I would like you to loan me the
7 money." So the bank lends him the money, and that is
8 cash out the door. The bank is going to expect interest
9 back, and they're going to expect that interest on that
10 cash they advanced the business, no matter what the cash
11 was used for. So we have financing costs, whether the
12 cash was used for what you all term as operating expense
13 or capital-related expense, but it's all cash out the
14 door to the investors.

15 **Q** And I agree with all of that, except Duke Energy
16 Carolinas isn't a bank, is it? You're a public utility.

17 **A** [K. SMITH] No, but we have investors, and they expect a
18 reasonable return.

19 **MR. NELSON:** No further questions. Thank you
20 both.

21 Thank you, Mr. Chairman.

22 **CHAIRMAN RANDALL:** Thank you.

23 Okay, Commissioners, questions. Commissioner
24 Howard.

25 <

EXAMINATION

BY COMMISSIONER HOWARD:

Q Good morning to both of you.

A [PANEL] Good morning.

Q Mr. Gharthey-Tagoe, I was curious – you were at all three night hearings.

A [GHARTEY-TAGOE] I was, yes.

Q And I guess – and in particular, the night hearing in Anderson, you sat by a young lady named Anne Graffunder?

A [GHARTEY-TAGOE] Yes.

Q And I think her story was probably one of the saddest I've heard, in my opinion.

A [GHARTEY-TAGOE] Yes.

Q But she had a light bill of something like \$36 a month, she had allocated to pay for her electricity. And at that point in time, we were talking about a \$28 basic facilities charge; now that's reduced. But tell me what your take was. Did you have a conversation with her? She sat by you, she said, and I know she did. But did you have a conversation with her, or what was your take on her situation versus other low-income people's situation?

A [GHARTEY-TAGOE] Like you, I was very much struck and touched by her story. She has a son. She told me a lot about her personal life and the challenges she faces.

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1 She's also got a medical condition that's got her on
2 disability, so she has limited income, as well. And I
3 was very touched by her story, and certainly recognized
4 that, in that case, somebody with such low usage – in
5 fact, I think she commented while she testified, and it
6 is true that I said I had never seen such low bills,
7 because I think her monthly usage was probably 248, or
8 so, kilowatt-hours. And she pulled it up. I showed her
9 how she could pull it up on our app. She didn't have
10 the app, so she went to the website, pulled it, and
11 showed it to me. So I was very struck by that.

12 Yes, you know, for somebody like that with such low
13 bills, an increase in the basic facilities charge
14 absolutely adversely impacts them to the extent they
15 cannot afford to pay. Yes.

16 Q What could or what does Duke do to help these people?
17 What kind of low-income assistance – do you have a
18 program you have available? I'm not talking about
19 social programs of other agencies; I'm talking Duke
20 Corporation itself.

21 A [GHARTEY-TAGOE] So we have our Neighborhood Energy Saver
22 program, for example, where we go into, typically,
23 lower-income homes with folks who do energy audits,
24 determine improvements that can be made to the home,
25 such as changing out light bulbs, such as recommending

1 insulation additions. We even look at waterflow, give
2 them new showerheads and so forth, all with a goal of
3 reducing their usage of electricity, or water in the
4 case of the showerheads, and ultimately reducing their
5 costs. That's one. We also have a program where, if
6 you're not in one of these neighborhoods or you live in
7 an apartment, you can actually call in; we'll come and
8 do an audit individually, at no cost to you, and make
9 some recommendations to you. We'll also leave you a kit
10 that you can self-install.

11 I've also mentioned the Share the Warmth program a
12 couple of times already today. We can refer you to
13 those kinds of programs for assistance.

14 We can also work with you, if you have trouble
15 paying your bill, on a payment plan, for example. So we
16 have those different initiatives that could be
17 beneficial to low-income customers.

18 **Q** Two things, and I know it's been in the water industry a
19 good bit, or somewhat, but round-up. Do you consider
20 the round-up program, and where – what's your mindset or
21 what's Duke's opinion of a round-up program?

22 **A** [GHARTEY-TAGOE] So, in – after we filed our rate case,
23 one of the things I did do was reach out to various
24 stakeholders. One of the ones I reached out to was AIM,
25 and Kristi Brock, who spoke at the Anderson hearing,

1 too, and she suggested round-up when she spoke. She had
2 actually spoken to me about it before, so it's something
3 I've been thinking about. I think it would be
4 beneficial. Much like the Share the Warmth, where we
5 encourage our customers to donate to a fund that
6 ultimately gets shared to lower-income customers to
7 assist them with their payments, round-up is an
8 opportunity for customers to – I don't know if folks
9 know how it works, but, essentially, if your bill is
10 \$10.50, you can opt to round it up to \$11 and then the
11 50 cents gets added to a fund that ultimately could be
12 coming – I mean, I don't think Duke would administer it,
13 but we would use agencies like AIM to administer it, so
14 that that could be an additional source of funds to help
15 others. I'm very interested –

16 Q Well, two things about it: Number one, it's voluntary.

17 A [GHARTEY-TAGOE] Yes.

18 Q It has to be voluntary. And number two, a third party
19 has to administer it.

20 A [GHARTEY-TAGOE] Yes. Yes. And so I've got our team
21 looking at that. We don't have the systems to implement
22 it now, but I told the team that's something I
23 absolutely want to implement. So we're looking at it
24 internally, and as soon as we're ready to, we will
25 propose something to the Commission.

1 Q You have any idea of how much additional income this
2 fund could generate, I mean, this round-up could
3 generate, or low-income fund?

4 A [GHARTEY-TAGOE] I do not. I do not. But part of the
5 work we're doing is trying to identify the utilities who
6 do it, and we'd have to find utilities, probably, with
7 the same customer base like ours, to see how much they
8 generate. But I don't know how much it would be.

9 Q What about pre-pay?

10 A [GHARTEY-TAGOE] So we have a prepay program, and in this
11 case we're recommending that we, you know, make it
12 available to everyone. We've had a pilot for the last
13 few years and, in this case, we're recommending it
14 become available to everyone. But that would be another
15 option, you're right, because in that case we would not
16 need a deposit from the customer, because, typically,
17 lower-income customers also do have a difficulty or a
18 challenge paying deposits. But with Prepay, you can
19 better control your usage and better control how much
20 you spend on electricity. And we have found through the
21 pilot program our customers are very satisfied with it.

22 Q I should know this, and I guess I do, but on your
23 advanced metering, do you have an opt-out provision?

24 A [GHARTEY-TAGOE] Yes, we did.

25 Q What percentage of your customers take advantage of the

1 opt-out?

2 A [GHARTEY-TAGOE] Very –

3 Q I'm talking about rough. I don't –

4 A [GHARTEY-TAGOE] Yeah, yeah. Very small percentage. I
5 believe it's less than 2 percent.

6 Q That take advantage of the opt-out?

7 A [GHARTEY-TAGOE] Yes.

8 Q Are they well aware of – I mean, is it advertised enough
9 to know that they have that option, or they just assume
10 when you put in advanced metering, that's how they've
11 got to go?

12 A [GHARTEY-TAGOE] I don't know that we advertise that
13 there's opt-out available. It's a schedule that's been
14 approved by the Commission. And so, when we do go into
15 a home and they say they don't want it, then we offer
16 them that option.

17 Q On your rate of return, going to rate of return, you
18 mentioned the 10.5, but you also mentioned it came in at
19 10.75. What was the complete range? What was the low
20 number on that range? Was the low number 10.5 or – when
21 your ROE expert gave you a range of ROEs, what was the
22 low number?

23 A [GHARTEY-TAGOE] Usually the range – and I think I'll
24 defer to Mr. Hevert on that one. But usually the range
25 is about 100 basis points, and the 10.75 would be sort

1 the top – or, the middle of the range. The 10.5
2 probably is the bottom of the range.

3 Q But there was a lower range.

4 A [GHARTEY-TAGOE] Yes.

5 Q In a basic facility charge, what are some of the risks
6 that your company and your industry take, to utilize, to
7 mitigate – to mitigate different things in industry,
8 different risks, different things in the industry, that
9 you would utilize your basic facility charge to help
10 mitigate? Other than what you've mentioned. Do you
11 understand my question?

12 A [GHARTEY-TAGOE] I'm not sure I do.

13 Q The basic facility charge is a fixed charge that you can
14 use to help offset any other costs.

15 A [GHARTEY-TAGOE] Yes.

16 Q And I guess that was my question. What costs do you
17 incur that you would consider the basic facility charge,
18 you know, taking care of or helping to mitigate those
19 costs?

20 A [GHARTEY-TAGOE] Yes, the basic facilities charge is
21 intended to cover the cost to make electricity available
22 to the customer. You know, some utilities call it a
23 service charge, some call it an availability charge.
24 But it's intended to capture the fixed costs that do not
25 vary with usage, to serve the customer. And we

1 originally proposed something that was less than a
2 dollar a day. We have since accepted ORS witness's
3 proposal of \$11.96, which is about 40 cents a day, to
4 have electricity available to the customer.

5 Q Well, then, let me follow up. How do you respond to
6 customers or people who complain that the use of a basic
7 facility charge would eliminate or offset their use of
8 energy efficiency programs or conservation programs?

9 A [GHARTEY-TAGOE] Well -

10 Q We heard that a lot at the night hearings. I'm sure you
11 did, too.

12 A [GHARTEY-TAGOE] I did, too. I did, too. Well, to the
13 extent that the energy efficiency programs or even
14 installation of solar sort of reduces your usage, your
15 cost that is calculated based on usage is lowered as you
16 implement energy efficiency and as you install solar.
17 So to the extent that we shift costs from the variable
18 rate to the fixed charge, it will show lower savings.
19 That is true. But I would say those savings probably
20 shouldn't have been true savings, if the basic
21 facilities charge is not an accurate representation of
22 the fixed charge.

23 Q Okay, thank you. Ms. Smith.

24 A [K. SMITH] Yes.

25 Q Talk about your PP&E program, your EDIT, I think you

1 called it. EDIT?

2 **A** [K. SMITH] Yes, the tax give-back. Yes, sir.

3 **Q** All right.

4 **A** [K. SMITH] Yes.

5 **Q** Tell me about that, and tell me about – you're asking
6 for a 20-year payback on the unprotected?

7 **A** [K. SMITH] Yes, on the unprotected.

8 **Q** How much upfront – how much money is in that group? How
9 long ago – how long have you been collecting that fund
10 and how?

11 **A** [K. SMITH] Oh, how long we've been collecting it. I do
12 not know how long we've been collecting it. It's a tax
13 entry that's made every year. But the unprotected is
14 basically based on property; it's just not the type of
15 property that is considered protected, so it probably is
16 over a longer period of time. But the exact years, I do
17 not know. But I can get you an answer to that, if you'd
18 like it. I think –

19 **Q** Well, I don't know – I don't know that I'd understand
20 it, to be honest with you.

21 [Laughter]

22 **A** [K. SMITH] These taxes are very – you know, I thought
23 the tax laws would make everything simpler, but I'm not
24 too sure about that.

25 **Q** Well, tell me the dif - – tell me – you had some other

1 assets, and I think other assets in your nonprotected,
2 or other assets –

3 A [K. SMITH] Yes.

4 Q Plants and all those are in the protected assets. The
5 nonprotected assets, you mentioned one thing was
6 regulatory liabilities. What are some other things that
7 would be categorized in the nonprotected category?

8 A [K. SMITH] The whole regulatory liability of these
9 deferred taxes are all related to a tax impact of some
10 type, whether it's a deferred, like on the – you know,
11 when you buy equipment, you have bonus depreciation, so
12 that creates a – we owe taxes, but due to bonus
13 depreciation, those taxes will be later. Bonus
14 depreciation is only used for tax purposes. So, for
15 example, if you have an asset and it's going to be –
16 it's got a 20-year life, 20-year depreciation, for tax
17 purposes we could speed up that and let's say take the
18 whole thing, 100 percent, the first year. Well, that
19 delays the payment of taxes, so we put the regulatory
20 liability on the books because eventually we're going to
21 have to pay those taxes, just not right now, because the
22 tax law allowed us to take bonus depreciation.

23 So that is one category, so it's basically timing
24 differences between when the tax is incurred, or the
25 cost is incurred, and we have to pay the taxes, is what

1 causes all the different tax liabilities – or sometimes
2 you have a tax asset. You can have either.

3 COMMISSIONER HOWARD: Thank both of you, very
4 much. Appreciate your answers.

5 CHAIRMAN RANDALL: Thank you.
6 Commissioner Belser.

7 EXAMINATION

8 BY COMMISSIONER BELSER:

9 Q Good morning.

10 A [PANEL] Good morning.

11 Q Let's see – I've got so many notes written here
12 [indicating]. Ms. Smith, I'm going to start with you,
13 if you don't mind.

14 A [K. SMITH] Okay.

15 Q Let's – on page 23 of your direct testimony, you
16 referenced the North Carolina Commission's order. On
17 lines three through six, you stated, "The North Carolina
18 Utilities Commission approved the company's request to
19 cancel the Lee nuclear project and permitted recovery of
20 the North Carolina allocable share to the company
21 investment in the Lee nuclear project, with some limited
22 exceptions." Did I read that correctly?

23 A [K. SMITH] Yes.

24 Q Okay. What exceptions were those that the Commission
25 listed, do you know?

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1 A [K. SMITH] Yes. We did not recover the cost of the
2 visitors' center that we were building. And I think
3 that was it, the visitors' center. And we did not get a
4 return on the amortization period.

5 Q So, plural "exceptions," there are only two?

6 A [K. SMITH] Yes. Oh, and the – yes, that's true. Oh,
7 and the non-depreciable land cost we removed.

8 Q Okay.

9 A [K. SMITH] But we removed those ahead of time.

10 Q Okay. And I think you discussed that with Mr. Elliott;
11 is that correct?

12 A [K. SMITH] Yes.

13 Q Are you – I think Mr. Gharthey-Tagoe talked about the
14 Prepay. Are you familiar with that program?

15 A [K. SMITH] Actually, I am very familiar with Prepay,
16 from a prior job.

17 Q Okay. Well, we heard some discussion about getting a
18 return on deferrals. But if y'all have customers that
19 are prepaying – and I understand it's something that
20 might be started – is there going to be interest
21 accruing on those customers' funds that would need to be
22 credited somehow?

23 A [K. SMITH] Actually, I think – well, I think the
24 majority of the customers who are going to use the
25 prepaid account are going to use it like they set up –

1 what we're suspecting; now, I'm not sure if this is what
2 is occurring or not. It will be, more likely, low-
3 income customers who can only pay like \$50 at a time.
4 So they'll put \$50 on it and then use that \$50 worth,
5 and then --

6 Q So it allows only, like, just pay maybe twice a month or
7 three times a month --

8 A [K. SMITH] Yeah, like three --

9 Q -- versus one whole --

10 A [K. SMITH] -- times a month.

11 Q -- one bill in arrears?

12 A [K. SMITH] Yeah, and I think, too -- I was in the
13 customer world for a while. I think a lot of customers,
14 you know, to go out and borrow from a neighbor a \$200
15 deposit is very hard, but they might be able to go out
16 and borrow \$50 to put on their prepaid account. So I
17 think it really helps the low-income customers. I don't
18 think people would be putting large amounts on it.

19 Q I just hear customer -- money coming in from the
20 customers, and I'm trying to figure out what's going on
21 with that.

22 A [K. SMITH] Now, we do pay money on our deposits. We pay
23 interest --

24 Q Well, that's --

25 A [K. SMITH] -- on our deposits.

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1 Q – required?

2 A [K. SMITH] Yes, it is required, but, yeah, it is done,
3 so...

4 Q That's it right now. I may come back to that.

5 A [K. SMITH] Okay.

6 Q Mr. Gharthey-Tagoe, it's good to see you this morning.

7 A [GHARTEY-TAGOE] Good to see you, too.

8 Q Thank you. I did see you at night hearings, and I have
9 some questions, too, about the smart meters. And if you
10 are not the appropriate person to answer those, I'd
11 appreciate you letting me know who can discuss those
12 with me, if you don't mind. First of all, there were a
13 number – well, I say a number, but, for a night hearing,
14 several people that complained about the AMI meters.
15 And you mentioned checking the bill of the one gentleman
16 that indicated the \$900. Did y'all check on any of the
17 other customers that indicated that their bills had
18 increased substantially after the installation of the
19 smart meter?

20 A [GHARTEY-TAGOE] I don't know if we checked all of them,
21 but there were – as you know, we had a team in the room;
22 and customers who wanted to engage with us, we engaged
23 with. And if they had billing questions, we had
24 somebody on the spot who could check that. But I have
25 not verified that every one of them was checked.

1 Q You don't have any results of any of those conversations
2 today?

3 A [GHARTEY-TAGOE] I do not, except for that one case that
4 seemed pretty egregious.

5 Q There were a couple of people that indicated that
6 installations may have been faulty. Do you know if
7 y'all have followed up on those?

8 A [GHARTEY-TAGOE] Yes. So, the one I did follow up on and
9 which I mentioned before, I think he made one of those –
10 that was one of his complaints, and we did check on
11 that. As I recall, there was an issue, an electrical
12 issue, that caused his – he said his strip heat to come
13 on, but I think the heat pump ended up going into
14 auxiliary heat. So it was an electrical issue. I'm not
15 sure it was directly as a result of the AMI meter being
16 installed, but it was an electrical issue at the home
17 that caused that to happen.

18 Q I'm not familiar with the operations of these meters,
19 but is there a factor that has to be coded into the
20 meter, as far as reading and calculating usage? I'm
21 just wondering if there could be a factor input that
22 might have created some issues with billing.

23 A [GHARTEY-TAGOE] I do not know that, but I doubt it. I
24 mean, I think, you know, the regulations allow customers
25 to request meters to be tested, I believe once a year.

1 And so I think there are some who've called and we've
2 come out and tested their meters. I don't think there's
3 any adjustment factor in the meter, itself, but — I
4 don't know if we have any witnesses remaining who can
5 speak to that, but maybe counsel can help me there with
6 potentially who the best witness might be.

7 Q Well, maybe I'll hear something later and I can ask that.

8 A [GHARTEY-TAGOE] Yeah, I think Jay Oliver was excused.

9 A [K. SMITH] And can I add, too, that there's also a
10 meter-testing program that the company has to go through
11 every year, and we have to test so many of our meters
12 and they have to be within a certain parameter.

13 Q Right.

14 A [K. SMITH] And so these would fall under that testing.
15 Plus, I think, as we understand, they're all tested
16 before they're put in.

17 Q Commissioner Howard asked you about the opt-out. Are
18 customers notified far in advance that their meter's
19 going to be changed out, so that —

20 A [GHARTEY-TAGOE] Yes.

21 Q — so that, if they wanted to opt out, they could?

22 A [GHARTEY-TAGOE] Yes.

23 Q And I believe that there is a monthly charge to those
24 customers, because you have to send a meter- — or,
25 somebody out to check the meter, and they're not read

1 remotely or however the smart meters are read?

2 A [GHARTEY-TAGOE] Correct.

3 Q Let's talk just a second about eliminating the charges
4 for the credit cards, or convenience fees.

5 A [GHARTEY-TAGOE] Yes.

6 Q Y'all - the company would still have to pay those fees;
7 is that correct?

8 A [GHARTEY-TAGOE] Yes.

9 Q And how would the company collect the fees? Or would it
10 just be spread out over all the customers, rather than
11 just those customers -

12 A [GHARTEY-TAGOE] Exactly. That's -

13 Q - that use -

14 A [GHARTEY-TAGOE] - what we're proposing in this case.

15 Q - a credit card or a debit card?

16 A [GHARTEY-TAGOE] All payment channels would be free.

17 Q What cost savings does the company experience from
18 having more customers use credit cards?

19 A [GHARTEY-TAGOE] We don't experience savings; we
20 experience cost, which is what we're trying to -

21 Q Well, currently, when bills come in, somebody's got to
22 get the mail. Somebody's got to open the mail.
23 Somebody's got to process the checks. If checks bounce,
24 there are going to be late fees and charges that
25 somebody has to deal with on that. You've got to run

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1 them down and get another, or put it back on the bill.
2 But if somebody is paying by credit card – and you
3 expect the numbers to increase, potentially, do you not?

4 **A** [GHARTEY-TAGOE] We do.

5 **Q** – you don't have to worry about chasing somebody down
6 for a late fee, or anything. So, are there not going to
7 be some savings, the more people you can shift over to
8 credit cards?

9 **A** [GHARTEY-TAGOE] Well, I can say –

10 **Q** I mean, I know we're talking 1/2 million customer
11 accounts here in South Carolina, but still.

12 **A** [GHARTEY-TAGOE] Yeah, and I'm not sure we'll get 100
13 percent adoption, at least not immediately. But we have
14 not determined if there will be any savings.

15 **COMMISSIONER BELSER:** I think that's it, right
16 now. Thank y'all very much.

17 **CHAIRMAN RANDALL:** Thank you, Commissioner
18 Belser. Is that everything?

19 **COMMISSIONER BELSER:** Yes, sir.

20 **CHAIRMAN RANDALL:** Okay. We're going to break
21 for lunch, and we'll continue with Commissioner
22 questions. We'll be back at 1:38.

23 [WHEREUPON, the witnesses stood aside.]

24 [WHEREUPON, the lunch recess was taken
25 from 12:38 to 1:40 p.m.]

A F T E R N O O N S E S S I O N

CHAIRMAN RANDALL: Please be seated. Okay.

We'll call this hearing back to order.

THEREUPON came,

K O D W O G H A R T E Y - T A G O E ,

K I M H . S M I T H ,

recalled as witnesses on behalf of Duke Energy Carolinas,
who, having been previously duly affirmed, were examined and
testified further as follows:

CHAIRMAN RANDALL: And we are still on
Commissioner questions, so, I think Commissioner
Hamilton?

COMMISSIONER HAMILTON: Thank you, Mr.
Chairman.

EXAMINATION

BY COMMISSIONER HAMILTON:

Q I'm happy to have y'all back this afternoon.

A [PANEL] Thank you

Q I'm sure you'd hoped to be through by this afternoon.

[Laughter]

But I just have a few questions. Kodwo, what is
the opt-out fee on the smart meters?

A [GHARTEY-TAGOE] I do not know it offhand, but back to a
question I got from Commissioner Belser earlier, we do
have Don Schneider here, who will testify later today,

1 who will have details.

2 **Q** Okay. Thank you, very much. This next question, either
3 one of you might want to chime in. Do you expect the
4 demand-side management and energy efficiency programs to
5 suffer any on the increasing cost in fixed costs?

6 **A** [GHARTEY-TAGOE] No, we're going to continue to push
7 that. Absolutely. We've been very effective in terms
8 of how many kilowatt-hours we've saved with our demand-
9 side management and energy efficiency programs. I
10 believe, you know, the savings are really tangible,
11 sizable, in the millions – hundreds of millions of
12 dollars, in fact, since these programs were initiated.
13 So we'll continue to push those. But clearly, you know,
14 if the variable charge is lower than it used to be,
15 before, the savings may not be as great as they were
16 before, but clearly there's still value in pushing
17 those, so they will not suffer.

18 **Q** Okay. And I know many people had some questions about
19 solar and the cost. What is the method now that you
20 have for residential solar, the amount they receive back
21 for excess power?

22 **A** [GHARTEY-TAGOE] They receive full retail credit for
23 excess power. So back to one of the public hearings,
24 there was a customer who claimed he was receiving only 4
25 or 6 cents. That's one of the questions I followed up

1 on, and that's not correct. They do receive full retail
2 credit for excess power that they put back on the grid.

3 COMMISSIONER HAMILTON: I had thought that was
4 correct, but thank you. I appreciate both of you
5 being here. Thank you, very much.

6 That's all I have, Mr. Chairman.

7 CHAIRMAN RANDALL: Thank you, Commissioner.
8 Commissioner Whitfield.

9 COMMISSIONER WHITFIELD: Thank you, Mr.
10 Chairman. That went a little quicker than I
11 thought.

12 EXAMINATION

13 BY COMMISSIONER WHITFIELD:

14 Q I've got a few questions for both of you. Some of it, I
15 may – you may end up punting some of it to Witness
16 Miller, and I understand that, but I think I'm going to
17 stay at a fairly high level enough to where we won't get
18 too far in the weeds, at least with your panel, on these
19 questions.

20 First, Mr. Gharthey-Tagoe, Commissioner Belser asked
21 you a question about the – kind of asked one of the
22 things I was going to ask you. I just want to do a
23 follow-up with her about the credit card/debit card
24 program. And of course you talk about it in your
25 testimony on page 23. What information – my follow-up

1 is what information did you use to conclude that credit
2 card payments would double in growth by 20 percent, or
3 up to 20 percent?

4 A [GHARTEY-TAGOE] It's an estimate. And our Witness Quick
5 will be able to provide additional details on that, but
6 I will say, today, when customers pay by credit card,
7 it's a fairly low percentage today. And based on
8 customer feedback, we know part of the fact that is a
9 low percentage and is also a major irritant for
10 customers is the fee that is charged by a third party.
11 It's not charged by Duke. We use a third-party vendor
12 to process those payments, and the third party charges
13 the fee. And it's a major issue of irritation and
14 dissatisfaction for our customers, and that's why we're
15 proposing it, but Witness Quick will be better prepared
16 to tell you how we came up with the estimate.

17 Q So, just a quick follow-up along those lines – and if
18 you need to punt it to Witness Quick, okay. By your
19 projections or by the company's projections, how much
20 will this fee impact each residential customer's bill?

21 A [GHARTEY-TAGOE] I'd like to defer that to Witness –

22 Q Witness Quick.

23 A [GHARTEY-TAGOE] – Quick.

24 Q Okay. And next, I kind of – kind of maybe for both of
25 you, I'm going to kind of be at a little bit of a high

1 level and start off with you, Mr. Gharthey-Tagoe, and Ms.
2 Smith, if you need to jump in, that's fine. And there
3 will be some for you down the road, too, but — so, we
4 won't leave you out. Mr. Gharthey-Tagoe, of course, a
5 large part of your request, here, is for the combined-
6 cycle plant in Commissioner Ervin's district up near the
7 community of Pelzer. And, of course, you've now had
8 almost a year for it to be — I think, next month, April,
9 it'll be a year since it came into service. Is that
10 correct?

11 A [GHARTEY-TAGOE] That's correct.

12 Q And, of course, 750 — well, actually, a little more than
13 750. Seven hundred and fifty-three [753] megawatts is
14 quite a large facility, of course, toward the level of
15 some of the nuclear base-load plants, in terms of
16 megawatts. But a couple of questions along those lines.
17 Now that you've had a year, how is that working in the
18 fleet, in the Duke system, and what benefits are you
19 seeing or is the company seeing? What benefits are
20 ratepayers seeing? What benefits are there overall to
21 reliability and so forth?

22 A [GHARTEY-TAGOE] It is working very well. I will say
23 Witness Immel is here, who can also address the
24 performance of our generating fleet. As I said in my
25 opening statement, it is a gas-fueled facility, so

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1 certainly the emissions from it are significantly less
2 than the coal plants that were at that same site before
3 this was built. With the low gas prices we have today,
4 it makes for – it gives an opportunity for the company
5 to run at lower cost than we otherwise would be. And
6 all those benefits flow directly to customers.
7 Certainly, having adequate generation is an important
8 factor in maintaining reliability of the system, as
9 well.

10 Q I want to talk about the Lee site in Cherokee County for
11 just a minute, and just briefly tie back to that
12 facility, to the combined-cycle facility. And I'm not
13 going to rehash – you all had a great exchange with Mr.
14 Elliott on the breakdown of the revenues and AFUDC for
15 the Lee facility in Cherokee County, so I'm not going to
16 rehash that. But back to his point about the percentage
17 that South Carolina ratepayers would've had to pay on
18 that facility, let's just be clear on this combined-
19 cycle gas plant. It's my understanding Duke does not
20 get all 753 megawatts; you only get 650, I believe. The
21 other is owned by North Carolina Electric Co-Ops. Is
22 that correct?

23 A [G HARTEY-TAGOE] North Carolina Electric Membership
24 Corporation, yes.

25 Q And let's go a little further and be clear. Unlike the

1 Lee nuclear site, all of the 650 that you receive does
2 go to South Carolina ratepayers only, with the exception
3 of the part that the North Carolina EMC gets?

4 A [GHARTEY-TAGOE] That's not correct.

5 Q That's not correct.

6 A [GHARTEY-TAGOE] All our generation, our system
7 generation, which means that some of it goes to serve
8 wholesale customers, some of it goes to serve North
9 Carolina customers, and some goes to serve South
10 Carolina customers. So there's definitely a cost
11 allocation that occurs to cover the cost of that Lee CC
12 plant.

13 Q Well, I was going to pull out the wholesale customers,
14 but there is a portion that – do you have a – do you
15 happen to know the breakdown, or is that for another
16 witness, of what portion North Carolina customers –

17 A [GHARTEY-TAGOE] I think Witness Smith can answer the
18 allocation.

19 A [K. SMITH] Yeah.

20 Q Or Miller?

21 A [K. SMITH] Yeah, no, I can –

22 Q Or are you going to – oh, Ms. Smith. Okay.

23 A [K. SMITH] Yeah, so, normally on our allocation, our –
24 we just allocated North and South Carolina at 70/30, but
25 our wholesale customers make up about 9 percent of Duke

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1 Energy Carolinas' system. So it would probably be
2 65/20/9, I think. So, 65, North Carolina; 20 percent,
3 South Carolina. And if you do the wholesale customers,
4 9 percent of –

5 Q And you're specifically talking about the combined-cycle
6 gas plant, only, in the breakdown you just gave me?

7 A [K. SMITH] Well, all of our generating plants –

8 Q Okay.

9 A [K. SMITH] – go into that, have that allocation –
10 they're all allocated, the costs recovered from all of
11 our three jurisdictions.

12 Q Jurisdictions, okay. So you've had almost a year with
13 that facility. Back to the Lee facility, the Lee
14 nuclear facility – and, again, I'm not going to rehash
15 what Mr. Elliott did, but I do want to ask a question
16 related to the cost in pursuing the NRC license and also
17 the other costs that we've approved in the order from
18 2011. That facility, you didn't get your NRC license
19 until about a year and a half, almost two years – not
20 quite two years ago?

21 A [K. SMITH] Yes, that seems about right. Yes.

22 Q And – right. And I just wanted to ask, maybe, if I
23 could – of course, you're stating you still have that,
24 and you still have the option of, you know, the option
25 is still on the table, is what you're saying, by not

1 turning that in. But I guess what I'm asking for, why
2 did you pursue a federal NRC license without going first
3 down the State process, like has been done in the past,
4 here? Does the company have a reason why they – and it
5 looked like to me it went fairly fast, because we
6 weren't part of that. But I noticed a notice, and then
7 within just a few months you had an NRC license – there
8 were some public hearings I think, and then you had the
9 license pretty quickly, whereas other applications have
10 taken two and a half or more years.

11 A [GHARTEY-TAGOE] Well, I think it took awhile. It was a
12 long process, and Witness Fallon is here and can address
13 that process with you. It was not a quick process at
14 the NRC. It does take awhile. I think there was always
15 an intent to come back and get a siting license or
16 certificate from South Carolina, as well. But the NRC
17 license, certainly if you don't get that, then you don't
18 do anything. And the license doesn't expire. So I
19 think Witness Fallon can give you more detail, but it
20 was not an either/or; it's a both.

21 Q I just wondered if there was some type of corporate
22 strategy as to why you went the federal route first, so
23 to speak.

24 A [GHARTEY-TAGOE] No.

25 Q No?

1 A [GHARTEY-TAGOE] Not that I'm aware of.

2 Q Okay. I want to move a little bit to another large cost
3 that you have here, is for the Catawba-Wateree
4 relicensing of all of the hydroelectric dams in that
5 Catawba-Wateree system with FERC. And I know that was a
6 lengthy process, and you've got about \$126 million.
7 Maybe you have it, or maybe I missed it. But what
8 portion of that – or do you have it broken out of what
9 portion of that was legal, the legal portion of that?

10 A [GHARTEY-TAGOE] I do not know that.

11 A [K. SMITH] I don't have –

12 Q Do you have that –

13 A [K. SMITH] – any of that.

14 Q Is there another witness that may have that?

15 A [K. SMITH] So, we can get it for you.

16 Q And I know that there are certain conditions that came
17 with the FERC 40-year license that you received, and you
18 are doing a lot of improvements, enhancements, that sort
19 of thing. I know some of those have not been done yet,
20 but some of them are ongoing. Could you – do you have a
21 little bit of information on that, or is that for
22 another witness?

23 A [K. SMITH] I think that would be for another witness.

24 Q Okay. We'll punt that one down to a later witness.

25 Lastly, Mr. Gharthey-Tagoe, during the night hearing, we

1 had some – I think you've been questioned a little bit
2 about this maybe from Mr. Nelson already, but I want to
3 go just one step further. There seemed to be a lot of
4 cases – I know you cited how many testified – of almost
5 a complete disconnect between your CSRs, your telephone
6 and marketing – your telephone people in the office,
7 your CSRs who were in the office, and your linemen and
8 your field personnel, your engineers, as to what's
9 actually going on in the field, and so much so that
10 customers were sounding like they were having a hard
11 time getting your people, your CSRs, to understand what
12 their problem was. Do you think that your CSR maybe
13 need some – you know, some physically – some physical
14 training, where they actually see physically what the
15 problem is, so that maybe they can better relate to the
16 customers when they call in and try to explain
17 specifically what the problem was? Because I heard that
18 in Anderson, Spartanburg, and Greenville. I heard that
19 all three places.

20 A [GHARTEY-TAGOE] Well, you know, our customer service
21 representatives are trained. They go through regular
22 training. They have periodic training to update them on
23 the business and the types of calls they're likely to
24 get. Certainly, you know, if they had more exposure to
25 what happens in the field, they would better understand

1 it. But I do think, or, again, to put it in context, I
2 do think that if you think about the number of calls we
3 get a day, the number of requests we get for folks to
4 come out and do something, that that may not – what we
5 heard in these night hearings may not necessarily be
6 representative of what happens every day.

7 I think, by and large, most of those calls we do
8 handle correctly. To the extent that there's additional
9 training required, that is a lesson learned from the
10 night hearings that I will take back to our operations
11 team.

12 Q Well, I'm just wondering if you just had those
13 discussions, or maybe you haven't had much time to
14 discuss anything since the night hearings, but there
15 were just so many that kind of stick in my mind. One,
16 the man that talked about the trucks being rolled, the
17 heavy transport trucks being rolled and all this
18 equipment coming out, and then nothing happened. And
19 there were a couple – I mean, that's one that sticks in
20 my mind, but there were several instances where it just
21 seemed pretty clear that your person inside the office
22 on the other end of that phone did not – and they also
23 have long wait times and hard to get through to – seem
24 to have problems getting through. A lot of them
25 express, you know, the lack of having a local office and

1 being able to come in and see someone face-to-face. I
2 know it hasn't been long since those hearings, but have
3 you had any thoughts or discussions along these lines of
4 how you might improve that?

5 **A** [GHARTEY-TAGOE] Yes, so, the gentleman whose case you're
6 referring to, that's one where I believe the letter he
7 showed you was one that was directed to me. I think it
8 did come to our office. And at that time, you know,
9 there was no action required at that time, because the
10 time had passed. His lights had been fixed. But that's
11 one of the kind of topics that I would take to our team,
12 operations team meeting, and ask what we could've done
13 differently, and to encourage our team to be more
14 responsive.

15 So we do get some of those calls, certainly, and we
16 try to address them as they come up. I will say, since
17 the night hearings, I have not had the opportunity to
18 investigate every complaint that came up during the
19 hearings.

20 **Q** And I certainly realize that was just last week.
21 Lastly, and I guess I'm going to stay with you on this
22 one, as well. Other complaints – and Mr. Nelson kind of
23 went this way, or maybe one of our Commissioners did,
24 talking about the smart meters. We heard, of course, a
25 lot of complaints about that. And I think you stated in

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1 response to a question on the stand this morning that
2 the resident you looked at who acknowledged his bill had
3 gone from \$400 to \$900, you said you checked and there
4 was no \$900 bill. But did you, in fact – without
5 calling that person's name – did you indeed check and
6 see that his bill may have gone up some, from –

7 A [GHARTEY-TAGOE] Yes.

8 Q – \$400 – in other words, if it wasn't \$900, was it \$500
9 or \$600?

10 A [GHARTEY-TAGOE] Yes. Yes. And as I explained in my
11 answer, too, there was an electrical issue that caused
12 his auxiliary heat in the heat pump to come on, which is
13 sort of an emergency heating system. So that would
14 definitely cause the bill to be higher than it otherwise
15 would be.

16 Q I don't guess you've had time to investigate some of the
17 other witnesses, public witnesses, who complained about
18 getting the smart meter and their bill going – I know –
19 again, I know it's been a short time.

20 A [GHARTEY-TAGOE] Not yet.

21 Q But we did seem to hear a lot of that.

22 A [GHARTEY-TAGOE] Yes. And I don't have the transcripts
23 of all the hearings yet. Some of them did talk to our
24 folks; some did not. That particular gentleman's case
25 just seemed sort of extreme, so that caused me to follow

1 up very quickly, and that was the outcome of my
2 investigation, yes.

3 COMMISSIONER WHITFIELD: Well, thank you.

4 That's all I have, Mr. Chairman.

5 CHAIRMAN RANDALL: Thank you, Commissioner
6 Whitfield.

7 Commissioner Ervin.

8 COMMISSIONER ERVIN: Thank you, Mr. Chairman.

9 EXAMINATION

10 BY COMMISSIONER ERVIN:

11 Q Good afternoon.

12 A [PANEL] Good afternoon.

13 Q In reviewing the prefiled testimony, Mr. Hevert – Robert
14 Hevert – am I pronouncing that correctly?

15 A [GHARTEY-TAGOE] Hevert.

16 Q Hevert. – indicated that the return on equity should be
17 in the range of 10.25 to 11 percent. I think you said
18 10.5 earlier. Subject to check, if he said 10.25, would
19 you agree that's probably the low end of your
20 perspective?

21 A [GHARTEY-TAGOE] Yes.

22 Q And I believe North Carolina – did you agree on a return
23 on equity of 9.9? Or did the Commission order that?

24 A [GHARTEY-TAGOE] We agreed with Public Staff on 9.9.

25 Q Well, if that was good enough for North Carolina

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1 ratepayers, why would that not be appropriate for South
2 Carolina ratepayers?

3 A [GHARTEY-TAGOE] Well, I think, after that case, interest
4 rates went up a little bit more. I do think that,
5 particularly with some of the proposals in the ORS's
6 testimony, our risk is higher here, among other things.
7 An ROE is supposed to be reflective of the risk of the
8 jurisdiction.

9 Q Well, interest rates have just come down this week,
10 haven't they?

11 A [GHARTEY-TAGOE] Well, those would be short-term rates.

12 Q Yes, sir.

13 A [GHARTEY-TAGOE] Right? And we tend to finance with
14 long-term —

15 Q Right. Over how many years, approximately?

16 A [GHARTEY-TAGOE] I will defer to Jack Sullivan on that.

17 Q Right. But long-term rates have recently come down, as
18 well.

19 A [GHARTEY-TAGOE] Well, I'll defer to Jack Sullivan on
20 that. But I would say — I mean, there's a need for
21 regulatory stability, and all that tends to impact risk.
22 But I think Mr. Hevert and Jack Sullivan will be able to
23 tell you more about how we arrived at our
24 recommendation.

25 Q But a 9.9 return on equity is not an unreasonably low

1 figure, is it?

2 A [GHARTEY-TAGOE] Well, I wouldn't say it's an
3 unreasonably low number, no.

4 Q It's what Dominion agreed to in our case, recently.

5 A [GHARTEY-TAGOE] Yes, I'm aware of that.

6 Q And so they thought it was reasonable. I just wonder
7 why you don't.

8 A [GHARTEY-TAGOE] Well, again, I think, in a settlement
9 context, there are other issues that are being
10 addressed. And in the totality of the circumstances, I
11 might be willing to take a 9.9 – right? – when other
12 factors are –

13 Q I see. Well, could it be that Duke Energy's CEO gets
14 this \$7 million bonus, in the event that the rate of
15 return exceeds 10 percent? Could that be one of the
16 factors that you're taking into consideration?

17 A [GHARTEY-TAGOE] No, sir.

18 Q Isn't it true that she got a \$7 billion incentive for a
19 bonus, if she got –

20 A [GHARTEY-TAGOE] Did you say \$7 billion?

21 Q Seven million –

22 A [GHARTEY-TAGOE] I'm sorry.

23 Q – bonus?

24 A [GHARTEY-TAGOE] In 2017, she got a \$7 million –

25 Q That's –

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- 1 A [GHARTEY-TAGOE] – retention –
2 Q – right.
3 A [GHARTEY-TAGOE] – bonus, yes.
4 Q And that was to get 10 percent ROE.
5 A [GHARTEY-TAGOE] No.
6 Q No?
7 A [GHARTEY-TAGOE] I don't believe so.
8 Q You don't think it was tied to that?
9 A [GHARTEY-TAGOE] No. It was a retention bonus.
10 Q Well, the *Charlotte Observer* said that. I just wondered
11 if we could verify it. Could you check that for us?
12 A [GHARTEY-TAGOE] Check the *Charlotte Observer*?
13 Q Yeah, just the story indicated – the business section
14 had an article that said that that was tied to her
15 return on equity for the shareholders, if she exceeded
16 the 10 percent return on equity.
17 A [GHARTEY-TAGOE] Okay, we can check that –
18 Q Good.
19 A [GHARTEY-TAGOE] – but I think her – like other
20 employees, she's got a base pay and incentive pay.
21 Q Right.
22 A [GHARTEY-TAGOE] And the incentive pay has certain
23 measures that have to be met. Certainly, earnings-per-
24 share is included in some of the metrics –
25 Q Sure.

1 A [GHARTEY-TAGOE] — so —

2 Q It's also true that she's the highest-paid CEO in the
3 nation for electric owned utilities, right?

4 A [GHARTEY-TAGOE] I don't think so. I mean, 2017, because
5 of that retention bonus, she may have been. But before
6 that, I believe in 2016, her compensation was about \$13-
7 point-something million.

8 Q She got a 55 percent increase from year to year, I
9 believe, from —

10 A [GHARTEY-TAGOE] For that one year. It's not a
11 recurring —

12 Q Right.

13 A [GHARTEY-TAGOE] — bonus, no.

14 Q And I also was interested to see that Duke Energy is
15 building a 40-story skyscraper in Charlotte, to house,
16 along with other things, to house part of your
17 operation. I'm just curious. It's a multiple-use
18 facility that's been announced, and you've asked for
19 permitting in the city to build it. It's going to have
20 over a million square feet, and portions of that
21 facility are going to be rented out to other tenants and
22 be available as a multi-use facility. Where do those
23 profits go?

24 A [GHARTEY-TAGOE] For renting space?

25 Q Yes, sir.

1 A [GHARTEY-TAGOE] I don't know that. Certainly, we would
2 not charge costs to customers rented out to third
3 parties and those profits not come back to customers.
4 Q I guess my question is, are the customers helping to pay
5 for the construction of that facility?
6 A [GHARTEY-TAGOE] Well, like other Duke – so, just a
7 little more context. You know, that facility is being
8 built to replace three existing facilities that we have
9 today, some of which are over 40 years old.
10 Q One of which is being leased, I believe. Is that right?
11 A [GHARTEY-TAGOE] Yes, the 400 South Tryon building.
12 Q That's right.
13 A [GHARTEY-TAGOE] And it's getting increasingly expensive
14 to maintain that space –
15 Q Yes, sir.
16 A [GHARTEY-TAGOE] – and we find it more prudent to move to
17 new space than continue the upkeep of three old
18 facilities.
19 Q But you're going to keep the other, what you call the
20 Duke Energy Building –
21 A [GHARTEY-TAGOE] The Duke Energy Center.
22 Q The Duke Energy Center will remain an asset?
23 A [GHARTEY-TAGOE] Correct.
24 Q And, but you are going to rent out to other third
25 parties, to lease that space out.

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1 A [GHARTEY-TAGOE] Yeah, I know about the commercial space –
2 Q Yes, sir.
3 A [GHARTEY-TAGOE] – and that rental.
4 Q I just – you know, you haven't disclosed the cost of
5 that project yet. I know that you bought the underlying
6 property for about \$27 million and change.
7 A [GHARTEY-TAGOE] Sounds about right.
8 Q Does that sound about right? But you haven't told the
9 public yet how much you're going to spend on the
10 skyscraper.
11 A [GHARTEY-TAGOE] Because of work developing the –
12 Q Still work in progress.
13 A [GHARTEY-TAGOE] Exactly.
14 Q But I guess, just from a ratepayers' perspective, I'm
15 wondering how that's financed, and could you – could
16 someone provide that information to us during the
17 hearing?
18 A [GHARTEY-TAGOE] Well, I'm sure Mr. Sullivan can help
19 with that. But, generally speaking, our facilities are
20 – you know, if part of it is used for the benefit of
21 customers, that will get –
22 Q Put in the rate base.
23 A [GHARTEY-TAGOE] – put in the cost of service.
24 Q As long as it's a reasonable rent.
25 A [GHARTEY-TAGOE] Absolutely.

1 Q Okay. And, but the other profits are going somewhere
2 else, and I'm curious to know where they're going. Is
3 that – it's a fair question, I think.

4 A [GHARTEY-TAGOE] Well, yeah. I mean, I would say, right
5 now, it has not been built, so –

6 Q Yes, sir.

7 A [GHARTEY-TAGOE] – there are no profits from it.

8 Q But there has to be some sort of facilities plan.

9 A [GHARTEY-TAGOE] Yeah. And so to the extent that we rent
10 out space that generates profit – again, I don't know
11 how that would be treated, but certainly that space
12 would not be charged to customers.

13 Q All right, sir.

14 A [GHARTEY-TAGOE] That much, I do know.

15 Q Fair enough. Ms. Smith, would you know any more about
16 that project? Could you help us?

17 A [K. SMITH] On the general allocation system, when they
18 look at the – when we allocate the cost of a building,
19 they look at the type of workers that are in the
20 building. So, if it's nonregulated –

21 Q Right.

22 A [K. SMITH] – they don't get to charge the regulated
23 entities. So, as Mr. Gharthey-Tagoe said, if there is –
24 if we are renting out space, then we will not charge the
25 South Carolina customers for that space. It would only

1 be the space that is being used to benefit the customers
2 of South Carolina.

3 Q I understand that part, and that's the only thing that
4 would be considered for the rate base. I was just
5 curious, and I just thought it was quite an undertaking
6 for a publicly owned utility to build a 40-story-high
7 skyscraper, and it just peaked my curiosity to know, you
8 know, what is — how is this being done.

9 A [K. SMITH] How it's being financed?

10 A [GHARTEY-TAGOE] You know, I think the financing
11 structure is a sale-leaseback.

12 Q Right.

13 A [GHARTEY-TAGOE] So we're selling it and then leasing
14 space back.

15 A [K. SMITH] Right.

16 Q And I guess the profits will go to the shareholders? Is
17 that basically the bottom line, to be a part of the
18 return on investment?

19 A [GHARTEY-TAGOE] I don't know. Again —

20 A [K. SMITH] I don't know, either.

21 A [GHARTEY-TAGOE] — I don't know if there will be profit,
22 because the point is, if it's not being used for
23 customers, it will not be charged to customers.

24 A [K. SMITH] Yes.

25 Q I understand. Fair enough. I'm pleased to hear that

1 you're interested in committing to the round-up program,
2 because I think that would be tremendously beneficial to
3 our ratepayers here in South Carolina, and in other
4 states that you all represent. And I commend you on
5 that decision. I think there are a lot of people that
6 would participate –

7 A [G HARTEY-TAGOE] I hope so.

8 Q – because South Carolina, as you know, has an issue with
9 people that are living at or under the poverty level.
10 And the rough calculation is we believe it's at least a
11 million or more families – not families, but people.
12 It's about roughly 5 million people in the State, and I
13 think about 20 percent are living in poverty. And so I
14 think you picked up on some of that at our public
15 hearings.

16 A [G HARTEY-TAGOE] Yes, I did.

17 Q And I commend you for substantially reducing the set
18 fees, because that would have had a tremendous impact on
19 low-usage customers, like the one you sat beside –

20 A [G HARTEY-TAGOE] Yes.

21 Q – and referenced earlier in your testimony, and it would
22 also have a devastating impact on low-income elderly,
23 disabled, and minority customers throughout the State –
24 throughout the rate base, that are struggling to make
25 ends meet. I think you heard some single mothers that

1 are working two, three jobs to try to pay bills and keep
2 the children fed. We heard some heartbreaking stories,
3 didn't we?

4 **A** [GHARTEY-TAGOE] We did.

5 **Q** And it really – I think it was time well spent. And I
6 want to thank the people that came out to share their
7 stories, because I think it does put things in
8 perspective. We want you to be successful as a company
9 and have a reasonable rate of return, but we also want
10 to be fair to our people, and that's why we're here, is
11 to be fair and just. So I don't ask these questions to
12 try to embarrass you, I really don't. But I think we
13 have to make an inquiry to reach a just result. I
14 appreciate you being with us today. Thank you.

15 **A** [PANEL] Thank you.

16 **CHAIRMAN RANDALL:** Thank you.

17 Commissioner Williams.

18 **VICE CHAIRMAN WILLIAMS:** Thank you, Mr.
19 Chairman.

20 **EXAMINATION**

21 **BY VICE CHAIRMAN WILLIAMS:**

22 **Q** Mr. Gharthey-Tagoe and Ms. Smith, thank you for being
23 here. Just a couple of questions for you, as we round
24 out this session. Mr. Gharthey-Tagoe, you had the
25 opportunity to attend all three night hearings last

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1 week; is that correct?

2 A [GHARTEY-TAGOE] That's correct.

3 Q And is it fair to say that the attendees of that night
4 hearing were somewhat concerned about the increase, the
5 proposed increase? Is that --

6 A [GHARTEY-TAGOE] That is fair.

7 Q -- a fair statement? My question to you, first question,
8 would be, based on what you heard at the night hearings,
9 would you consider the access to electricity a right or
10 a privilege? Or stated another way, a necessity or a
11 luxury?

12 A [GHARTEY-TAGOE] I believe it's a necessity. And that's
13 why, frankly, we are a regulated public utility. That's
14 one of the reasons why we are regulated, to make sure
15 that, as a monopoly, the Commission balances the
16 customers' opportunity for just rates against the
17 company's opportunity to earn a fair return.

18 Q Thank you for sharing that. I'm sure you remember that
19 several attendees raised that point and questioned --
20 actually made that exact statement and sort of raised
21 that question. And that leads to the next question of
22 how much is too much. We talked about the rate of
23 return on equity, and I think you know this, but this
24 hearing is live-streamed. Our staff has done a great
25 job to help us with opening the door, if you will, so

1 ratepayers can see what we do. And we actually
2 advertised that at the public hearings, so I would
3 imagine that many of those who attended the public
4 hearings are actually tuning in right now. And I'd like
5 to give you an opportunity to address them. What I'm
6 trying to figure out is, with the initial proposal for
7 the basic facility charge – I believe it was \$28 – it's
8 my understanding you believe, Mr. Gharthey-Tagoe and Ms.
9 Smith, that that request is supported by the prefiled
10 testimony and the evidence, if you will?

11 A [GHARTEY-TAGOE] Correct.

12 A [K. SMITH] Yes.

13 Q So that's a true statement –

14 A [GHARTEY-TAGOE] Yes.

15 Q – in your opinion? Okay. So, what changed between your
16 initial proposal and the time where you decided to
17 consent to ORS's basic facility charge, the \$11.96?

18 A [GHARTEY-TAGOE]. Yes. So, certainly, in developing the
19 case, I had talked to a few, but not many customers.
20 The opportunity to go through the night hearings and
21 hearing the feedback from the customers was absolutely
22 impactful. Separately, I've had conversations with
23 other stakeholders, including parties in this case.
24 That's all very impactful, as well.

25 I think our goal was to send the proper price

1 signals, in terms of what it costs to make electricity
2 available. And at the time we filed, we absolutely
3 believed that that was the reasonable thing to do. But
4 having heard the feedback, and certainly having heard
5 some of the testimony filed about gradualism, we took a
6 second look, we stepped back, and we said, "Perhaps
7 that's not the right thing to do now," and that's why we
8 accepted ORS's recommendation on the basic facilities
9 charge.

10 Q Thank you for sharing that input with me. Is there any
11 reason why you can't accept the 9.3 rate of return as
12 proposed by ORS?

13 A [GHARTEY-TAGOE] Yes, because I don't think that's fair.
14 I don't think that's a just and reasonable return for
15 our investors, who provide the funds for us to maintain
16 safe, reliable, and affordable electricity in South
17 Carolina.

18 Q Okay. And, again, we have a technical staff, we go
19 through all the prefiled testimony, so I have an
20 understanding of what you just said. But if you could
21 break it down for just the average ratepayer: You don't
22 think it's fair. Why is it not fair?

23 A [GHARTEY-TAGOE] So, in regulating utilities and their
24 prices we charge, there's very long-standing precedent.
25 It goes all the way back – I think the most cited case

1 is from 1923, US Supreme Court case called *Bluefield*
2 *Waterworks*. And in there, the Supreme Court said when a
3 company devotes its assets to providing public service
4 to the community, as a public utility, as we are, a
5 monopoly company like ours, the regulators are to ensure
6 just and reasonable rates. But on the other hand, the
7 investors who provide that funding to operate the
8 business also deserve a fair return on their
9 investments.

10 The return-on-equity component is one component of
11 our costs. As Witness Smith said earlier, it is a cost.
12 There are people who provide funding for us to make
13 investments that serve customers, and those people have
14 other places to put their money. They could put it in
15 other utilities, they could put it in other companies.
16 It all depends on what they get in return for that
17 investment.

18 So when other companies are earning a return of,
19 say – I believe it was 10.85 that we saw for Georgia
20 Power on the list that was shown, they'd probably rather
21 put their money there than put it in a company that is
22 only allowing 9.3. If we can't – so, which means it'll
23 cost us more to raise those funds. If we cannot raise
24 those funds or we raise it at a higher price, ultimately
25 customers suffer. Right? Because either you don't have

1 the funding to do what you need to do to provide
2 reliable, safe service, or, you know, it costs too much,
3 and the commissions ultimately have to step in and raise
4 rates to allow us to provide that kind of service that
5 our customers expect.

6 So it is an element of cost. I've heard the term
7 used "profit" many times, but it is costs that we incur.
8 And based on precedent, based on regulatory policy, all
9 that must be paid for.

10 Q So based on that position, there's an argument to be
11 made that, if this Commission were to decide on a rate
12 of return that could be considered – that you would
13 consider unreasonable, is there an argument to be made
14 that it could ultimately negatively impact ratepayers?

15 A [GHARTEY-TAGOE] Absolutely. Ms. Smith –

16 Q Oh, I'm sorry. Go ahead, Ms. Smith.

17 A [K. SMITH] I'm the neighborhood person that explains
18 utility rates all the time. They find out you work for
19 Duke, you work in the Rates Department. But I remember
20 when I was younger, and my aunt always invested in
21 utilities, and I said, "Why do you do that, and not
22 invest in something that's going to make you a lot more
23 money over time?" She goes, "Because I know, if I
24 invest in the utility, I am going to receive a
25 reasonable return. I will never receive a huge return,

1 but I will always get a reasonable return and I will not
2 ever get, you know, no return." So that's why people
3 invest in utilities, because they are assured of a
4 reasonable return, with the regulatory compact, though
5 they know they'll never make a huge profit.

6 A [GHARTEY-TAGOE] So, the other element to this is – and
7 this is stuff I've read in the press down here, lately,
8 that we are guaranteed a return. There is no guarantee
9 to what you allow in this case. It is the opportunity
10 for us, with good management and things working out.
11 Because, again, we've talked about using a historical
12 test period. We're using historical numbers, costs, and
13 prices from 2017, when we all know we're setting rates
14 for the future. The new rates will not be implemented
15 until June 1 – at least that's what we've asked for. So
16 almost by definition, by the time you leave here, you're
17 behind. And as we stated in our Application, as of the
18 end of the test period, we are earning a return of, I
19 believe it's 6.48 percent, as opposed to the 7.89 that
20 this Commission – on total return on rate base, not ROE,
21 so that factors in the cost of debt plus the cost of
22 equity.

23 You know, the last case in 2013, this Commission
24 allowed an overall return of 7.89 percent – subject to
25 check. It's in our Application. And by the end of the

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1 test year, we were ending below that.

2 And so it is not a guaranteed return. It is an
3 authorized return that we have an opportunity to earn.
4 And the only reason, typically, we will come in for a
5 rate case is because we're not earning that.

6 Q Thank you both for sharing that information with us all.
7 A couple of questions regarding the energy conservation
8 programs. I believe it was in Greenville where there
9 was testimony at the public hearing that a ratepayer
10 lived in either a manufactured home or mobile home, and
11 that that ratepayer requested an energy audit, but she
12 was told that Duke Energy does not perform energy audits
13 on either mobile homes or manufactured homes. Is that –
14 do you know anything about the truth of that statement?

15 A [GHARTEY-TAGOE] That's one I have not followed up on
16 yet, but that would be a surprise to me. The issue with
17 manufactured housing is there is only so much you can
18 do, and that's part of the issue we have in South
19 Carolina. I think I read somewhere that about 20
20 percent of our homes are manufactured homes, and that's
21 why we have higher bills. We don't have the highest
22 rates in the country – which is another fallacy I've
23 read in the papers, recently. We don't have the highest
24 rates in the country. There are people in Hawaii who
25 are paying 34 cents per kilowatt-hour. We're not paying

1 that in South Carolina. But, we have high usage because
2 our customers use electricity for heating, for cooling,
3 for lighting, for cooking, whereas perhaps in the
4 Northeast they could heat with oil or gas, and
5 electricity is used in cooling and lighting. So they
6 don't use as much, or they may not use as much.

7 The problem with manufactured housing is it's not
8 well insulated. They don't tend to be very energy
9 efficient, right? So you could change out light bulbs –
10 and I don't know why our folks wouldn't offer to do
11 that, because that's what we do in the other homes.
12 They have lights, too. So we would do that. To the
13 extent we could add insulation, we could do that.

14 So I seriously doubt that we would have told a
15 customer who lived in a manufactured home that we don't
16 perform energy audits for manufactured homes.

17 Q Do you think it's worth the investment to whole-home
18 retrofit low-income housing to try to increase energy
19 efficiency?

20 A [GHARTEY-TAGOE] So it depends on the costs, right? In
21 all our energy-efficiency programs, there's a cost-
22 benefit that is reviewed. We had an ex parte briefing
23 here only a couple of months ago that just focused on
24 that. So there's some point where it's just not cost-
25 effective to make the investment. So, there could be

1 cases like that.

2 Q Ms. Smith, this question is for you.

3 A [K. SMITH] Okay.

4 Q Why is the Lee nuclear plant site any more valuable than
5 the same acreage without the benefit of a combined
6 operating license, if there's a very small potential it
7 will ever be used for a nuclear facility?

8 A [K. SMITH] The Lee nuclear plant, we did develop the
9 plans for it, and that's what the money is we're asking
10 for, was the development of the plans. So we have
11 incurred that cost, and it was prudently incurred when
12 we incurred the cost. It was a few dockets here in
13 South Carolina, and we've been reporting how we've
14 incurred our costs. So we are trying to recover the
15 prudently incurred costs of our development. Does that
16 answer your question?

17 Q Yes, it does.

18 A [GHARTEY-TAGOE] May I answer that? So, the site is also
19 – you know, we've been holding onto the license. Right?
20 There are not too many sites – the license goes with the
21 site. So if we give up the site or dispose of it, you
22 may have to go through the entire licensing process all
23 over again. So that makes the site valuable.

24 Q Sure. I'm finished. I'm going to yield my time to
25 Commissioner Ervin. Thank you, Mr. Gharthey-Tagoe and

1 Ms. Smith.

2 A [GHARTEY-TAGOE] Thank you.

3 EXAMINATION

4 BY COMMISSIONER ERVIN:

5 Q Just to follow up on that site, it's very unlikely that
6 you'll ever build a nuclear facility on that site; isn't
7 that true?

8 A [GHARTEY-TAGOE] Sitting here today, yeah, the stars are
9 not aligned for that. But circumstances do change.

10 Q So that license, today, is really not worth anything
11 more than the paper it's written on.

12 A [GHARTEY-TAGOE] I think it's worth something,
13 absolutely. Much like government policy changed, and
14 carbon all of a sudden was not as — an important policy
15 objective of the present government, we could have
16 another government that puts a significant price on
17 carbon, and gas prices could go up. And all of those
18 are important factors in determining whether nuclear is
19 the best generation option.

20 Q But that facility was never used and useful, correct?

21 A [GHARTEY-TAGOE] To the extent you mean we didn't
22 complete the facility?

23 Q Right.

24 A [GHARTEY-TAGOE] That's true.

25 Q You abandoned it.

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1 A [GHARTEY-TAGOE] We didn't complete the facility, yes.

2 Q And since we're talking nuclear, have you investigated
3 the possibility of keeping the nuclear plants that
4 you're currently operating in service longer, because
5 they are clean energy, they do provide that base when
6 the sun is not shining for, you know, peak use, and so
7 forth. I hope you have some plans to try to keep those
8 licenses active and keep them in service.

9 A [GHARTEY-TAGOE] We're absolutely investigating that
10 opportunity right now.

11 Q And I hope the Congress may help you with some
12 incentives, because we're trying to save our planet, and
13 nuclear is a clean energy option.

14 A [GHARTEY-TAGOE] Absolutely is.

15 Q And so I'm glad to hear that. I would encourage you to
16 pursue those options, and try to shut down the coal
17 facilities you do have in operation in North Carolina,
18 or convert them to gas. I hope you're considering, as
19 well.

20 A [GHARTEY-TAGOE] Well, there are at least two of our
21 facilities that we've connected dual-fuel to, so they
22 can be fueled by gas or coal. And to the extent that
23 gas is cheaper, we do fuel them by gas.

24 Q Thank you, sir.

25 A [GHARTEY-TAGOE] Thank you.

1 CHAIRMAN RANDALL: Thank you.

2 Commissioner Belser.

3 COMMISSIONER BELSER: Thank you, Mr. Chairman.

4 EXAMINATION

5 BY COMMISSIONER BELSER:

6 Q I thought I was finished, but I'm not. I'm sorry. Just
7 a couple of questions, and one of them is in response to
8 an answer you gave when you cited the *Bluefield*
9 decision. And you're an attorney, correct?

10 A [GHARTEY-TAGOE] Actually, I don't have a license
11 anymore.

12 [Laughter]

13 Q Oh. Well, you were trained as an attorney, were you
14 not?

15 A [GHARTEY-TAGOE] Yes. Yes, ma'am.

16 Q You know how to read the law?

17 A [GHARTEY-TAGOE] I do.

18 Q And you talked about *Bluefield*, and basically, the
19 progeny of cases that followed were referring to good
20 management; is that correct?

21 A [GHARTEY-TAGOE] Yes.

22 Q I think some of the terminology is "economical and
23 efficient" management, is it not?

24 A [GHARTEY-TAGOE] Correct.

25 Q And so, granted, looking at the return, and a reasonable

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1 return on investment, there also needs to be a
2 corresponding economical and efficient management
3 consideration; is that correct?

4 A [GHARTEY-TAGOE] That is correct.

5 Q And that's one of the tasks that this Commission must
6 consider, as well; is that not correct?

7 A [GHARTEY-TAGOE] That is true.

8 Q I want to go and refer to Mr. Cowling's testimony, and I
9 believe his testimony is now being stipulated in? Is
10 that correct?

11 A [K. SMITH] Correct.

12 Q And so, if you need to defer to someone else, please do.
13 But he made a couple of statements in his testimony that
14 I'd like to follow up on. One was on page 17, where he
15 stated: Installing new LED fixtures to replace obsolete
16 MV and incandescent technology results in a new product
17 being connected to the existing electrical wires, thus a
18 change in the character of service for the future_[sic].

19 And I wanted to key in on that change in character
20 of the service. If customers are having their obsolete
21 fixtures replaced with LEDs, is this going to impact
22 those customers that are on the Greenwood Rate? Is that
23 going to be considered a change in service for those
24 customers, such that they could be removed from the
25 Greenwood Rate?

1 A [GHARTEY-TAGOE] I don't know the answer to that. I
2 think that's a legal issue.

3 Q Okay. Can you task one of your witnesses to follow up
4 with that, please, so we can get a response to that in
5 this proceeding?

6 A [GHARTEY-TAGOE] Certainly will.

7 Q Also, in Mr. Cowling's testimony, on page 18 he stated
8 that, with respect to Greenwood outdoor lighting
9 customers, there are other outdoor lighting service
10 providers to choose from in addition to Duke Energy
11 Carolinas, so a Greenwood customer will have available
12 options. Would you happen to know those options, or is
13 that something somebody else needs to answer? Outdoor
14 lighting.

15 A [GHARTEY-TAGOE] I don't know specifically what Greenwood
16 customers – what options they would have, but I do know
17 there are other companies that provide outdoor lighting
18 – commercial companies – that provide outdoor lighting
19 services. Duke is not the sole provider. We provide
20 the electricity, but not necessarily the fixtures.

21 Q If a customer were to get one of those fixtures from
22 another company, with Duke providing that service, what
23 schedule would that be on? Is that a Greenwood Rate or
24 is it an outdoor lighting rate separate from the
25 Greenwood Rate?

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1 A [GHARTEY-TAGOE] I do not know the answer to that.

2 Q If somebody can let me know who can answer those, I'd
3 appreciate it. Thank you, very much.

4 A [GHARTEY-TAGOE] Thank you.

5 CHAIRMAN RANDALL: Thank you, Commissioner
6 Belser.

7 Commissioners, any other questions?

8 [No response]

9 Ms. Smith, any redirect?

10 MS. H. SMITH: Yes, very - very little.

11 REDIRECT EXAMINATION

12 BY MS. H. SMITH:

13 Q Do you remember, earlier this morning, Mr. Gharthey-
14 Tagoe, when you were asked some questions by Mr. Culley
15 on the Jeff Bailey testimony and exhibits?

16 A [GHARTEY-TAGOE] I do.

17 Q And do we have other witnesses in the Rate Design
18 Department who would be able to address Mr. Bailey's
19 testimony?

20 A [GHARTEY-TAGOE] Yes. Mr. Pirro, Michael Pirro, is our
21 rate-design witness in this case.

22 Q Okay, thank you. And do you remember Mr. Culley asking
23 you some questions about the company's decision to
24 depart from its cost-allocation methodology proposed in
25 the 2013 rate case in South Carolina? I think he

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1 characterized it as a change from the last case. Is
2 that correct?

3 A [GHARTEY-TAGOE] Yes, I recall that.

4 Q Okay. And is it a change from North Carolina?

5 A [GHARTEY-TAGOE] No. In fact, the minimum system cost-
6 of-service study that we propose in this case was
7 recently approved in North Carolina,

8 Q And are there parties in this case who support the
9 minimum system allocation?

10 A [GHARTEY-TAGOE] Yes. I believe the ORS did not oppose
11 it.

12 Q Do you recall Mr. Neal asking you about the national
13 average of basic facility charges for investor-owned
14 utilities?

15 A [GHARTEY-TAGOE] I do.

16 Q And if you're looking at a national view, is it also
17 important to look at a South Carolina view for
18 utilities?

19 A [GHARTEY-TAGOE] Absolutely.

20 Q And so, how would that same statement work out, if you
21 were focusing on South Carolina utilities?

22 A [GHARTEY-TAGOE] I believe I mentioned that there's a
23 number of cooperatives in the State who have higher
24 basic facilities charges than we do now and than what
25 we've agreed to in this case. And I think it's

1 relevant, because I remember he said something about
2 whether we wanted to be a cooperative, and we do not,
3 but it's relevant because there are neighborhoods where
4 you have cooperative customers on one side of the street
5 – I think in Laurens County, I've met some customers
6 from there – and utility customers close by, so they do
7 talk and they do compare rates.

8 Q And in the situation of co-ops, their members – they're
9 member-owned, correct?

10 A [GHARTEY-TAGOE] Correct.

11 Q And so the members participate in those decisions about
12 what the basic facilities charge might be?

13 A [GHARTEY-TAGOE] Correct.

14 Q And do you remember – this is for Kim Smith. So, Ms.
15 Smith, one is coming at you.

16 A [K. SMITH] Okay.

17 Q Do you remember when Mr. Elliott was asking you about
18 the South Carolina piece of the Lee nuclear costs? Do
19 you recall that?

20 A [K. SMITH] Yes, I do.

21 Q And he wanted to know the systemwide number for Lee
22 nuclear. Do you recall that?

23 A [K. SMITH] Yes.

24 Q Okay. And that would – is that North and South
25 Carolina?

- 1 A [K. SMITH] Yes.
- 2 Q Okay. And so, did North Carolina allow recovery of
- 3 AFUDC?
- 4 A [K. SMITH] Yes, they did.
- 5 Q And moving on, Mr. Gharthey-Tagoe, do you recall when
- 6 counsel for Walmart was asking you questions regarding
- 7 the company's proposed return on equity?
- 8 A [GHARTEY-TAGOE] I do.
- 9 Q And just one little thing to clean up for the record.
- 10 Do you recall when counsel asked you about why the
- 11 company chose to propose a 30 percent increase in its
- 12 ROE? Do you remember the use of the word "percent"?
- 13 A [GHARTEY-TAGOE] I do not remember that.
- 14 Q Well, just for clarity of the record. What is the
- 15 company's current ROE – allowed ROE?
- 16 A [GHARTEY-TAGOE] Allowed is 10.2 percent.
- 17 Q Okay. And the company proposed –
- 18 A Is 10.5 percent.
- 19 Q So would the difference, then, be 30 basis points, not
- 20 30 percent?
- 21 A [GHARTEY-TAGOE] Thirty basis points.
- 22 Q Thirty percent would be a very different number,
- 23 correct?
- 24 A [GHARTEY-TAGOE] Absolutely.
- 25 Q Do you also recall when Commissioner Howard was asking

1 you about low-income options for Duke Energy Carolinas'
2 customers? Do you remember that?

3 **A** [G HARTEY-TAGOE] I do.

4 **Q** And do you recall conversations, for example, about
5 Prepaid Advantage?

6 **A** [G HARTEY-TAGOE] I do.

7 **Q** Are there other programs, such as Pick Your Own Due
8 Date? Are there other options like that, that can help
9 customers?

10 **A** [G HARTEY-TAGOE] Yes, Pick Your Own Due Date. I think we
11 heard some customers at the night hearings about
12 inability to pick due dates, but that's one of the
13 programs that's facilitated by the AMI meter. Customers
14 can now absolutely pick their due dates to match up with
15 when they get paid, or when they have the money
16 available, for whatever reason. But that helps
17 customers, as well, particularly those on fixed incomes
18 who have their pay or their checks coming in at
19 particular times of the month, so they can better align
20 their payments with when they get monies in.

21 **Q** And so the program just referenced, Pick Your Own Due
22 Date, and the Prepaid Advantage program that was
23 discussed, both of those are relatively recent programs;
24 is that correct?

25 **A** [G HARTEY-TAGOE] They are. And they are all facilitated

1 by the AMI meter.

2 Q Okay, thank you. And before we leave the AMI meters, do
3 you remember Commissioner Belser's question about meter
4 testing?

5 A [GHARTEY-TAGOE] Yes.

6 Q And do we have a witness in this case who would be able
7 to talk about meter testing and these smart meters?

8 A [GHARTEY-TAGOE] Yes, Don Schneider.

9 Q Okay. And do you remember Commissioner Belser asking
10 you about whether or not there were any savings that
11 could be attributed to the company's proposal regarding
12 credit card fees?

13 A [GHARTEY-TAGOE] Yes,

14 Q And do we also have a witness in this case who would be,
15 maybe, perhaps better suited to answer those questions
16 of the Commissioner?

17 A [GHARTEY-TAGOE] Yes. I think I said it was Ms. Quick.

18 Q There you go. Okay. Thank you. And do you recall
19 Commissioner Whitfield asking you some questions about
20 cost allocation for generation?

21 A [GHARTEY-TAGOE] Yes,

22 Q And so, in a cost-of-service study, such as in a rate
23 case, is it your understanding that you allocate away
24 wholesale?

25 A [GHARTEY-TAGOE] Yes.

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1 Q Okay. Which leaves the retail component?

2 A [GHARTEY-TAGOE] Yes,

3 Q And what's the retail split between North and South
4 Carolina?

5 A [GHARTEY-TAGOE] For DEC, it's about 70/30.

6 Q Are you aware of any generation or transmission that is
7 not split along those lines in shared costs between the
8 two states?

9 A [GHARTEY-TAGOE] No, I —

10 Q Our generating plants, for example, and transmission
11 lines?

12 A [GHARTEY-TAGOE] Yeah, I'm not aware of any generating
13 plants owned by the utility, other than perhaps that
14 which was constructed to comply with North Carolina
15 REPs, the Renewable Energy Portfolio Standards
16 requirements. But even there, we do assign based on
17 avoided cost, to South Carolina.

18 Q Okay. And, Ms. Smith, when you calculate the revenue
19 requirements for rate cases, such as this one, how are
20 the costs of the company's generating plants, like Lee
21 CC and our other generating plants and transmission
22 lines, how are they allocated when you propose a revenue
23 requirement?

24 A [K. SMITH] They are allocated across the states.

25 Q Okay. And that split is?

1 **A** [K. SMITH] Seventy/thirty.

2 **Q** Okay, thank you. And do you recall – I'm almost done
3 here, so thank you. Do you recall being asked about
4 some of the smart meter issues that were raised at the
5 public hearings, Mr. Gharthey-Tagoe?

6 **A** [GHARTEY-TAGOE] Yes, I do.

7 **Q** Okay. And did you have, with your team, smart-meter
8 professionals that talked to some of those customers?

9 **A** [GHARTEY-TAGOE] Yes, we did, on each night of the public
10 hearing.

11 **Q** And could perhaps Mr. Schneider follow up on some of
12 those questions?

13 **A** [GHARTEY-TAGOE] Absolutely.

14 **MS. H. SMITH:** Thank you.

15 That's all I have. Thank you.

16 **CHAIRMAN RANDALL:** Thank you, ma'am. Your
17 "real quick" rivals another attorney's "real quick"
18 that I've had before, here.

19 I know that, in my total immersion training
20 back in November, when we have redirect, we can
21 have some recross to those particular questions.
22 So is there any recross?

23 **MR. NELSON:** I've got a few questions.

24 **CHAIRMAN RANDALL:** Step right up.

25 **MR. NELSON:** I promise I don't have any more

1 than three or four.

2 CHAIRMAN RANDALL: Three or four, you said.

3 Okay.

4 MR. NELSON: Yes, sir.

5 RECROSS EXAMINATION

6 BY MR. NELSON:

7 Q A follow-up to the question Ms. Smith just asked you
8 regarding the difference between operating plants and
9 the South Carolina/North Carolina transmission lines,
10 isn't it true that last time Duke came in for a rate
11 case, that there were certain costs associated with the
12 North Carolina Clean Smokestack Act – and I might be
13 naming that wrong – that Duke voluntarily agreed not to
14 include in costs associated or sent to South Carolina?

15 A [GHARTEY-TAGOE] I do know there were some clean-
16 smokestacks charges that were not charged to South
17 Carolina, yes. But to be clear, it was the federal
18 Clean Air Act was passed that changed that cost – or,
19 those costs – that are being shared between the two
20 states now.

21 MR. NELSON: I think everything else is just
22 related to Commissioner questions, so I don't think
23 those are proper. I think I'm done. Thank you.

24 MR. NEAL: Mr. Chairman, may I? Sorry to go
25 out of order.

1 **RE CROSS EXAMINATION**2 **BY MR. NEAL:**

3 **Q** Just quickly, Mr. Gharthey-Tagoe, in relation to this
4 question about comparing Duke Energy Carolinas to
5 cooperatives in South Carolina, are you familiar with
6 the Help My House program that cooperatives offer their
7 members in South Carolina?

8 **A** [GHARTEY-TAGOE] I am not.

9 **Q** Well, if you were to – subject to check – learn about
10 this tariffed on-bill financing program, this inclusive
11 financing program that allows for comprehensive whole-
12 house energy-efficiency retrofits without any upfront
13 payments by customers, would that be something you'd be
14 open to exploring to offer to your customers in South
15 Carolina?

16 **A** [GHARTEY-TAGOE] I am willing to explore that if it will
17 help my customers.

18 **MR. NEAL:** Thank you.

19 **CHAIRMAN RANDALL:** Thank you.

20 Okay. Any other recross?

21 [No response]

22 Okay. Then, thank you for your testimony, and
23 you may step down.

24 **MS. H. SMITH:** At this time, Mr. Chairman,
25 we'd like to ask that Mr. Gharthey-Tagoe be excused.

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1 I would like to hold Ms. Smith on rebuttal to maybe
2 come back and pick up some of the questions we
3 might have some follow-up on.

4 **CHAIRMAN RANDALL:** Granted.

5 [WHEREUPON, Witness K. Smith stood aside
6 and Witness Gharthey-Tagoe was excused.]

7 **MS. H. SMITH:** Just another housekeeping
8 matter, while we're transitioning here.

9 We next will call Mr. Chris Fallon and Dr.
10 Diaz to the stand. And while we're shifting around
11 here, I wanted to take care of a couple of
12 procedural matters.

13 The company and parties had agreed to
14 stipulate a few witnesses for Duke, and we'd like
15 to enter their testimony into the record as if
16 given orally from the stand. So this would include
17 the prefiled testimony and exhibits of James
18 Cowling, Kimberly D. McGee, John Panizza, and
19 that's direct testimony for all three of those
20 witnesses. We would also like to move into the
21 record as if given orally from the stand the direct
22 testimony of Mr. Jay Oliver, as well as Mr.
23 Oliver's Direct Exhibit 1. I would note, for
24 clarity of the record, that while Mr. Oliver filed
25 rebuttal and additional exhibits, they were related

1 MS. H. SMITH: With that I will turn it over
2 to Mr. Marzo.

3 MR. MARZO: Good afternoon, Commissioners.
4 With your permission, Mr. Chairman, I will
5 begin with Mr. Fallon and move to Dr. Diaz, on
6 direct.

7 CHAIRMAN RANDALL: Hang on one second and let
8 us get them sworn in.

9 MR. MARZO: Oh, I'm sorry.

10 [Witnesses affirmed]

11 THEREUPON came,

12 CHRISTOPHER M. FALLON,

13 NILS J. DIAZ, Ph.D.,

14 called as witnesses on behalf of Duke Energy Carolinas, who,
15 having been first duly affirmed, were examined and testified
16 as follows:

17 DIRECT EXAMINATION

18 BY MR. MARZO:

19 Q Mr. Fallon, please state your full name and your
20 business address for the record.

21 A [FALLON] Christopher M. Fallon, 550 S. Caldwell Street,
22 Charlotte, North Carolina 28202.

23 Q And by whom are you employed and in what capacity?

24 A [FALLON] I'm employed by Duke Energy Renewables, and I
25 am Vice President, Duke Energy Renewables and Commercial

1 Portfolio.

2 Q Mr. Fallon, on November 8, 2018, did you cause to be
3 prefiled in this docket 35 pages of direct testimony and
4 one exhibit – Exhibit Fallon 1 – consisting of 35 pages?

5 A [FALLON] Yes.

6 Q Did you also prefile errata to your direct testimony on
7 January 22, 2019?

8 A [FALLON] Yes.

9 Q Do you have any other changes or corrections that you
10 need to make to your testimony or exhibits in this case?

11 A [FALLON] No, I do not.

12 Q Are they true and correct to the best of your knowledge?

13 A [FALLON] Yes, they are.

14 Q Would your answers be the same if you were asked those
15 questions today.

16 A [FALLON] Yes, they would.

17 MR. MARZO: Mr. Chairman, at this time, I
18 would ask the prefiled direct testimony of Mr.
19 Fallon be copied into the record as if given orally
20 today.

21 CHAIRMAN RANDALL: The prefiled direct
22 testimony of Christopher Fallon will be entered
23 into the record as though given orally from the
24 stand.

25 MR. MARZO: Thank you, Mr. Chairman. I'd also

1 ask that Mr. Fallon's exhibits be marked for
2 identification.

3 CHAIRMAN RANDALL: Okay. Mr. Fallon's
4 exhibits will be marked as Exhibit No. 17.

5 [WHEREUPON, Hearing Exhibit No. 17 was
6 marked for identification.]

7 BY MR. MARZO:

8 Q Dr. Diaz, could you please state your full name and your
9 business address for the record?

10 A [DIAZ] Nils Diaz, 3414 West Gables Court, Tampa,
11 Florida.

12 Q And, Dr. Diaz, by whom are you employed and in what
13 capacity?

14 A [DIAZ] I'm employed by The ND2 Group, and I am the
15 managing director.

16 Q Dr. Diaz, did you cause to be prefiled in this docket 42
17 pages of direct testimony and three exhibits consisting
18 of Exhibit NJD-1, consisting of two pages, NJD-2,
19 consisting of one pages, and NJD-3, consisting of two
20 pages?

21 A [DIAZ] Yes.

22 Q Do you have any corrections or changes you need to make
23 to your direct testimony or to your exhibits?

24 A [DIAZ] No.

25 Q Are they true and correct, to the best of your

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1 knowledge?

2 A [DIAZ] They are.

3 Q Would your answers be the same if you were asked those
4 same questions today?

5 A [DIAZ] Yes.

6 MR. MARZO: Mr. Chairman, at this time, I
7 would ask that the prefiled direct testimony of Dr.
8 Diaz be copied into the record as if given orally
9 here today.

10 CHAIRMAN RANDALL: The prefiled direct
11 testimony of Dr. Nils Diaz will be entered into the
12 record as though given orally from the stand.

13 MR. MARZO: Thank you, Mr. Chairman. I'd also
14 ask that Dr. Diaz's exhibits be marked for
15 identification.

16 CHAIRMAN RANDALL: Dr. Diaz's exhibits will be
17 marked as Exhibit No. 18.

18 [WHEREUPON, Hearing Exhibit No. 18 was
19 marked for identification.]

20 MR. MARZO: Thank you, Mr. Chairman.

21 BY MR. MARZO:

22 Q Mr. Fallon, do you have a summary of your testimony?

23 A [FALLON] Yes, I do.

24 Q Mr. Fallon, would you please give that summary?

25 A [FALLON] Good afternoon, Commissioners.

1 I filed direct testimony in this case. My direct
2 testimony provides background on the Lee nuclear project
3 development activities and associated costs.

4 In our Application in this case, Duke Energy
5 Carolinas requests recovery of the South Carolina
6 allocable share of project development costs of
7 approximately \$125 million. As I will explain, these
8 costs were prudently incurred for the benefit of Duke
9 Energy Carolinas' customers.

10 Duke Energy Carolinas' customers and the
11 communities we serve have benefited greatly from Duke
12 Energy Carolinas' nuclear fleet and have enjoyed safe,
13 reliable, emission-free, and cost-effective energy for
14 decades. In the 2005 timeframe, Duke Energy Carolinas'
15 Integrated Resource Plan identified the need for
16 significant generation capacity additions. The
17 generation planning environment at this time was
18 characterized by extreme volatility in natural gas
19 prices, expected impacts of the 2005 Clean Air
20 Interstate Rule, and other possible carbon-limiting
21 environmental regulations, as well as the positive
22 support for nuclear generation afforded by the Energy
23 Policy Act of 2005 and the actions of the South Carolina
24 General Assembly. Based on these considerations and
25 other factors, Duke Energy Carolinas identified nuclear

1 generation as the least-cost supply-side alternative.
2 Consequently, Duke Energy Carolinas started development
3 work on new nuclear as an option to meet its customers'
4 needs and announced in 2006 the selection of the Lee
5 site for possible nuclear expansion.

6 Duke Energy Carolinas filed a combined license
7 application in 2007 with the Nuclear Regulatory
8 Commission. Also in 2007, the company filed an
9 Application for Approval of Decision to Incur Nuclear
10 Generation Preconstruction Costs with this Commission,
11 to ensure the project remained an option to serve
12 customers when needed, as identified in the company's
13 IRP. On June 9, 2008, the Commission issued an order
14 approving Duke Energy Carolinas' decision to incur
15 preconstruction costs.

16 In 2011, Duke Energy Carolinas filed an additional
17 project development application requesting approval for
18 additional preconstruction costs. In July 2011, the
19 Commission approved a settlement agreement among Duke
20 Energy Carolinas, ORS, and some of the intervening
21 parties. In accordance with the Commission's order, the
22 company continued to incur only those costs necessary to
23 keep the Lee nuclear project available as an option in
24 the timeframe as it was needed to serve customers and
25 the company kept the Commission abreast of that progress

1 through regular reporting.

2 At the time of the Commission's 2011 order, Duke
3 Energy Carolinas projected that it would receive the COL
4 in 2013. However, the receipt of the COL was delayed by
5 several factors, many of which were outside Duke Energy
6 Carolinas' control, as Dr. Diaz explains in his
7 testimony. Duke Energy Carolinas continued to incur
8 costs for Lee nuclear project in order to preserve the
9 option of building Lee nuclear project to have it
10 available to meet needed dates contained in Duke Energy
11 Carolinas' IRP.

12 Capital spending on the Lee nuclear project after
13 2013 declined substantially, as project development
14 activities continued to be significantly limited to only
15 the minimal amount necessary to keep the nuclear option
16 available. Throughout this project, Duke Energy
17 Carolinas has taken a methodical, deliberate, and
18 measured approach to evaluate and pursue new nuclear,
19 which has allowed the company to maintain nuclear as a
20 future option while also avoiding some of the
21 significant challenges that have been encountered by
22 early adopting utilities who have undertaken full
23 construction. Duke Energy Carolinas has been consistent
24 that we'd make a decision regarding construction of the
25 Lee nuclear project after receipt of the COL.

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PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1 The COL for the Lee nuclear project was received at
2 the end of 2016. Since that time, significant events
3 outside the control of Duke Energy Carolinas, such as
4 the bankruptcy of Westinghouse, the exit of Westinghouse
5 from the construction business, and the abandonment of
6 the V.C. Summer project have led Duke Energy Carolinas
7 to the conclusion that the project, as originally
8 envisioned, is no longer prudent to pursue. As a result
9 of these risks and uncertainties, abandonment of the Lee
10 nuclear project is now the best option for our
11 customers. The company will continue to maintain the
12 COL. The COL does not expire and has value for Duke
13 Energy Carolinas' customers because it eliminates the
14 long-lead time required for federal permitting and
15 authorization of nuclear construction, and will allow
16 Duke Energy Carolinas to pursue the option of future
17 nuclear at the Lee site when and if it is in the best –
18 when it is best for our customers.

19 This concludes my summary.

20 MR. MARZO: Thank you, Mr. Fallon.

21
22 [PURSUANT TO PREVIOUS INSTRUCTION, THE
23 PREFILED DIRECT TESTIMONY, INCLUDING
24 CORRECTED PG. 27 SUBMITTED 1/18/19, OF
25 CHRISTOPHER M. FALLON FOLLOWS HEREINAFTER]

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2018-319-E

In the Matter of:	)	
	)	
Application of Duke Energy Carolinas, LLC	)	DIRECT TESTIMONY OF
For Adjustments in Electric Rate Schedules and	)	CHRISTOPHER M. FALLON
Tariffs	)	FOR DUKE ENERGY
	)	CAROLINAS, LLC

I. INTRODUCTION

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Christopher M. Fallon and my business address is 550 South
3 Caldwell Street, Charlotte, North Carolina 28202.

4 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

5 A. I am employed by Duke Energy as Vice President of Duke Energy Renewables
6 and Commercial Portfolio. I assumed this position on November 1, 2016. Prior
7 to assuming my current position, I was Vice President of Nuclear Development
8 from January 1, 2012 through October 2016.

9 **Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL**
10 **QUALIFICATIONS.**

11 A. I hold a Bachelor of Science Degree and a Master of Science Degree in
12 Electrical Engineering from Clemson University. I am a licensed professional
13 engineer in North Carolina.

14 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?**

15 A. Yes. I have participated in allowable ex-parte briefings on the IRP and
16 GridSouth.

17 **Q. PLEASE DESCRIBE YOUR DUTIES AS VICE PRESIDENT OF**
18 **NUCLEAR DEVELOPMENT.**

19 A. I was responsible for Duke Energy's overall new nuclear generation strategy,
20 with a strong focus on the pursuit of combined licenses ("COLs") from the
21 Nuclear Regulatory Commission ("NRC"), initially for the William States Lee
22 Nuclear Station Units 1 & 2 in Cherokee County, South Carolina (the "Lee

1 Nuclear Project” or the “Project”). After the merger with Progress Energy, I
2 assumed responsibility for the development of the Shearon Harris Nuclear Plant
3 Units 2 & 3 in New Hill, North Carolina, and the Levy Nuclear Plant Units 1 &
4 2 in Levy County, Florida.

5 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

6 A. My testimony provides background on the Lee Nuclear Project development
7 activities and preconstruction costs submitted in this case for cost recovery.

8 **Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?**

9 A. Yes. Attached as Exhibit 1 to my testimony is the “Final Report to the Public
10 Staff of the North Carolina Utilities Commission Independent Investigation of
11 the Prudence & Reasonableness of the Costs Incurred by Duke Energy
12 Carolinas, LLC to Develop the W.S. Lee III Nuclear Plant (“Project”) and its
13 Request to Cancel the Project dated January 22, 2018” prepared and submitted
14 by Global Energy & Water Consulting, LLC (“Global Energy”). Global Energy
15 was retained by the North Carolina Utilities Commission (“NCUC”) Public
16 Staff to review the Lee Nuclear Project development costs in connection with
17 pending rate proceedings in North Carolina in NCUC Docket No. E-7, Sub
18 1146. Global Energy found that Duke Energy Carolinas, LLC’s (“DE
19 Carolinas” or the “Company”) decisions regarding the Lee Nuclear Project
20 costs were appropriate at the time they were made and that the expenditures to
21 obtain the COLs were reasonable and prudent.

1 Q. WHAT PRECONSTRUCTION COSTS RELATED TO THE LEE
2 NUCLEAR PROJECT DEVELOPMENT IS THE COMPANY SEEKING
3 TO RECOVER IN THIS CASE?

4 A. DE Carolinas incurred actual preconstruction costs for the development of the
5 Lee Nuclear Project totaling approximately \$558 million through June 30,
6 2018.¹ The costs are specifically made up of Combined License Application
7 (“COLA”) Preparation, NRC Review and Hearing Fees, Pre-Construction and
8 Site Preparation, Land and Right of Way Purchases, Supply Chain,
9 Construction Planning and Engineering, Operational Planning, Post COL,
10 Allocated, and Allowance for Funds Used During Construction (“AFUDC”)
11 through December 31, 2017. The specific details of the costs have been
12 routinely reported to the Public Service Commission of South Carolina (the
13 “PSCSC” or “Commission”) as part of the Company’s reporting requirements
14 per the Commission orders approving the Company’s decision to incur Lee
15 Nuclear Project preconstruction costs. The Company is requesting Commission
16 approval to recover the South Carolina retail allocable share of the Lee Nuclear
17 Project preconstruction costs.
18 These actual costs, along with estimated additional expenditures through May
19 31, 2019, form the basis for the pro forma that serves as the support for the
20 Company’s rate requests in this case as presented by DE Carolinas Witness Kim
21 Smith. The total balance for which the Company is requesting recovery from
22 South Carolina retail customers is approximately \$125 million.

¹ All costs stated at system total unless otherwise noted.

1 Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

2 A. The remainder of my testimony is organized as follows:

3 II. LEE NUCLEAR PROJECT LICENSING BACKGROUND

4 III. PRIOR COMMISSION DECISIONS REGARDING LEE
5 NUCLEAR PROJECT DEVELOPMENT COSTS

6 IV. DECISION TO ABANDON THE LEE NUCLEAR PROJECT

7 V. COST RECOVERY

8 VI. CONCLUSION

II. LEE NUCLEAR PROJECT LICENSING BACKGROUND

9 Q. PLEASE BRIEFLY DESCRIBE THE LICENSING PROCESS
10 UNDERTAKEN TO PURSUE NUCLEAR DEVELOPMENT.

11 A. DE Carolinas has continually included nuclear energy, a proven carbon-free
12 base load technology, as a viable resource in ensuring fuel diversity and
13 reliability for South Carolina customers in its integrated resource planning
14 (“IRP”) process. In the middle of the last decade, DE Carolinas along with
15 many utilities across the country, began the process to license new nuclear
16 generation. This effort by DE Carolinas was spurred by what was at the time
17 an environment of high natural gas prices, extreme volatility in natural gas
18 prices, the expected impacts of the 2005 Clean Air Interstate Rule and other
19 possible carbon limiting environmental regulations as well as the positive
20 support for nuclear generation afforded by the Energy Policy Act of 2005
21 (“EPAAct”).

1 To build and operate a new nuclear reactor, DE Carolinas is required to
2 obtain a license under either the new process in 10 CFR Part 52 ("Part 52") or
3 obtain a construction permit and operating license under the previously existing
4 10 CFR Part 50 ("Part 50") process. Under the new Part 52 process, which DE
5 Carolinas selected to obtain the Lee Nuclear Project COL, the NRC issues a
6 combined operating and construction license, which the NRC describes as a
7 combined license, to applicants. The COL provides a licensee the ability to
8 construct, and upon meeting certain criteria, operate a new nuclear reactor. In
9 addition, the NRC also certifies new nuclear reactor designs, which is
10 particularly important because these certified designs can be referenced by the
11 applicant seeking approval to construct and operate the new reactor rather than
12 having to demonstrate the safety of the designs on its own. The Westinghouse
13 AP1000 Pressurized Water Reactor ("AP1000") design was the first new
14 passive reactor design for which the NRC issued a final design certification.

15 Although intended to be an improvement over the prior Part 50 licensing
16 process, the new Part 52 licensing process still has a significant lead time when
17 compared to permitting other generation resources such as combined cycle
18 natural gas generation. The long lead time needed for licensing and constructing
19 new nuclear units led DE Carolinas to proactively act to ensure that nuclear
20 generation was available to customers when needed, based on the base load
21 need identified in its IRP.

1 Q. DID DE CAROLINAS SUBMIT A COMBINED LICENSE
2 APPLICATION WITH THE NRC?

3 A. Yes. DE Carolinas submitted a COLA with the NRC for two AP1000 reactors
4 on December 13, 2007.

5 Q. HAS THE NRC ISSUED A COL FOR THE LEE NUCLEAR PROJECT?

6 A. Yes. On December 19, 2016, the NRC issued COLs for the Lee Nuclear Project
7 under Part 52 that allows the utility to construct the units at the Lee Nuclear
8 Project site and operate the units for 40 years following an NRC finding under
9 10 CFR 52.103(g) that the acceptance criteria in the COL are met.

10 Q. IS DE CAROLINAS REQUIRED TO IMMEDIATELY BUILD THE
11 NEW NUCLEAR PLANT IN ORDER TO MAINTAIN THE LEE COL?

12 A. No. A COL grants permission but does not compel the licensee to build and
13 operate the plant. Nor is there a requirement that DE Carolinas start
14 construction within a specified period of time. The Part 52 license provides the
15 flexibility to start construction at the appropriate time. Once the NRC issues
16 the license, they have made a determination that the reactor design on the
17 selected site provides adequate protection of public health and safety, the
18 environment, and the common defense and security. From time to time, as new
19 information is learned that might affect the safety determination by the NRC,
20 the license may need to be updated to confirm that the design provides
21 protection given the new information. As AP1000 units have proceeded with
22 construction in China and the U.S., numerous design changes to the AP1000
23 design have been required. Changes that were deferred for post-COL inclusion

1 into the Lee Nuclear Project licensing basis will need to be incorporated into
2 the Lee Nuclear Project COL for the plant to be constructed. In addition,
3 submittal of an annual Final Safety Analysis Report ("FSAR") update and
4 recurring regulatory reporting are important to maintaining the COL. The
5 license expires 40 years after construction of the new units is completed and the
6 NRC has issued its 52.103(g) findings, as stated previously.

7 **Q. WHAT IS THE CURRENT STATE OF THE LEE NUCLEAR PROJECT?**

8 A. As discussed above, the Lee Nuclear Project has been granted a COL. The COL
9 does not expire and has value for DE Carolinas customers because it eliminates
10 the long-lead time required for nuclear construction projects and preserves the
11 nuclear option for DE Carolinas customers. Thus, the Lee site will continue to
12 be an option for the Company's customers as part of the Company's long-term
13 generation planning efforts. However, at this time, the Company has
14 determined that it is no longer feasible to develop the Project as originally
15 envisioned and has abandoned the project and is only investing those costs
16 necessary to maintain the COL and site at a minimum level. The Company will
17 continue to evaluate both the need for power and the timing for future nuclear
18 and update this Commission through its annual IRP filing.

III. PRIOR COMMISSION DECISIONS REGARDING LEE NUCLEAR
PROJECT DEVELOPMENT COSTS

1 **Q. WHEN DID THE COMPANY DETERMINE THE NEED TO BEGIN**
2 **PLANNING FOR NEW NUCLEAR?**

3 **A.** Through its Annual Plan process, beginning in 2005, DE Carolinas identified
4 the need for significant capacity additions by summer 2016 and identified
5 nuclear generation as a least cost supply-side alternative to meet part of that
6 need. At the time, there had been renewed interest in new nuclear generation
7 in the United States. This renewed interest was attributable to several factors,
8 including (a) a need for new base load generation capacity over the next decade
9 in many areas of the country; (b) recognition, both internationally and
10 domestically, in the environmental benefits of nuclear generation as the focus
11 on carbon emissions heightened, particularly as climate change regulation
12 received greater consideration; (c) the need for American business and industry,
13 for whom the price of electricity can be a significant component of overall
14 operating costs, to remain competitive in global markets as other countries
15 maintained or even increased their reliance on nuclear generation; (d) rising and
16 often volatile prices associated with the fuels used in fossil generation assets,
17 particularly natural gas but also coal; and (e) increasing concerns about our
18 nation's energy security and energy independence. Because of these factors,
19 the EPAct contained various provisions that encouraged the development of
20 new nuclear generation. At the same time that these exogenous economic
21 factors began to prevail, nuclear generation technology, design, and safety had

1 improved markedly. The NRC had also made changes to the licensing process
2 (the Part 52 process described above) for new nuclear plants that were
3 anticipated to remove uncertainty and to enhance the efficiency of the licensing
4 process.

5 Around that same time, in 2006, the South Carolina General Assembly
6 expressed its support of new nuclear generation in its June 1, 2006, Joint
7 Resolution of the General Assembly of South Carolina, "A Concurrent
8 Resolution to Advance the Need for Electric Utilities to Build New Nuclear
9 Power Plants in South Carolina and to Urge the Office of Regulatory Staff
10 ("ORS") and the Public Service Commission to Encourage Such
11 Consideration." H. 5326.

12 **Q. FOLLOWING THE JOINT RESOLUTION, DID THE SOUTH**
13 **CAROLINA GENERAL ASSEMBLY PASS LEGISLATION**
14 **REGARDING NEW NUCLEAR CONSTRUCTION AND ADVANCE**
15 **COMMISSION APPROVAL OF A UTILITY'S REQUEST TO INCUR**
16 **PRE-CONSTRUCTION COSTS?**

17 A. Yes. S.C. Code Ann. § 58-33-225, effective May 1, 2007, was enacted as part
18 of the Base Load Review Act ("BLRA") and provided that at any time prior to
19 filing an application or a combined application under the BLRA, a utility may
20 file a request with the Commission and ORS to review the utility's decision to
21 incur preconstruction costs for a potential nuclear-powered facility.² The

² Similar legislation was also passed in 2007 in North Carolina expressly providing for commission approval of a utility's decision to incur nuclear project development costs. See N.C. Gen. Stat. §62-110.7.

1 statute further provided that prudent preconstruction costs must be properly
2 included in the utility's plant-in-service and must be fully recoverable in rates
3 in future proceedings under the BLRA unless the record shows that individual
4 items of cost were imprudently incurred or other decisions subsequent to the
5 issuance of a project development order were imprudently made considering
6 the information available to the utility at the time. In addition, the statute
7 provided that if the utility abandons the project after issuance of a prudency
8 determination, the utility may defer the preconstruction costs and calculate
9 AFUDC on the balance to be recovered in rates in the next general rate
10 proceeding or revised rates proceeding, provided that the utility proves by a
11 preponderance of the evidence, that its decision to abandon the project was
12 prudent. Thus, S.C. Code Ann. § 58-33-225 provided utilities with assurance
13 that the significant costs spent pursuant to a nuclear project development order
14 would be recoverable unless the Commission determines the costs were
15 imprudently incurred. Thus, the BLRA and the North Carolina General Statute
16 § 62-110.7 provided important assurances upon which DE Carolinas relied on
17 in moving forward with its decision to pursue the Lee Nuclear Project COL.

18 **Q. PRIOR TO THE COMPANY'S REQUEST TO CANCEL THE LEE**
19 **NUCLEAR PROJECT IN 2017 DID DE CAROLINAS' ANNUAL PLANS**
20 **SUPPORT THE DEVELOPMENT OF THE LEE NUCLEAR PROJECT?**

21 **A.** Yes. In each Annual Plan filed with the Commission between 2006 and 2016
22 the Lee Nuclear Project continued to be identified as a cost-effective option to
23 meet base load energy needs for customers. It is important to note that over that

1 period, the date upon which the Lee Nuclear Project was projected to be needed
2 by customers has changed due to a variety of factors that have been thoroughly
3 reviewed through the integrated resource planning process. The earliest need
4 dates forecasted for the two Lee Nuclear Project units in the 2016 Annual Plan
5 were 2024 and 2026.

6 **Q. DID THE COMPANY MAKE ANY FILINGS WITH THIS**
7 **COMMISSION PURSUANT TO S.C. CODE ANN. § 58-33-225**
8 **REGARDING DEVELOPMENT OF THE LEE NUCLEAR PROJECT?**

9 A. Yes. On December 7, 2007, in Docket No. 2007-440-E, pursuant to S.C. Code
10 Ann. § 58-33-225, DE Carolinas filed an Application for Approval of Decision
11 to Incur Nuclear Generation Pre-Construction Costs (the "2007 Application").
12 In the 2007 Application, DE Carolinas requested approval of its decision to
13 incur the South Carolina allocable share³ of preconstruction costs of up to \$230
14 million through December 31, 2009 for the Lee Nuclear Project to ensure the
15 project remained an option to serve customers in the 2018 timeframe. At the
16 time, DE Carolinas anticipated incurring preconstruction costs of
17 approximately \$70 million through December 31, 2007 and \$160 million from
18 the time period January 1, 2008 to December 31, 2009.

³ The South Carolina allocable share is 24.0911%.

1 **Q. WHAT WAS THE BASIS FOR DE CAROLINAS ESTIMATE OF**
2 **PRECONSTRUCTION COST FOR THE LEE NUCLEAR PROJECT?**

3 **A.** The estimate was based on the best information available to the Company at the
4 time and DE Carolinas stated that as information was refined during the
5 development process, the estimate could be substantially impacted, and it would
6 update the Commission accordingly. DE Carolinas explained that no final
7 decision had been made to construct the facility and it would retain significant
8 flexibility to adjust the development and construction plans in light of
9 additional information to be gained in future years.

10 **Q. DID THE COMMISSION APPROVE THE COMPANY'S REQUEST?**

11 **A.** Yes, the Commission issued an order approving the Company's request on June
12 9, 2008, finding DE Carolinas decision to incur the South Carolina-allocable
13 portion of Lee Nuclear Project pre-construction costs reasonable and prudent.
14 In the 2008 order, the Commission stated that its approval did not constitute
15 approval of the reasonableness and prudence of specific project development
16 activities or recoverability of specific items of cost.

17 **Q. DID DE CAROLINAS FILE ANY SUBSEQUENT PROJECT**
18 **DEVELOPMENT APPLICATIONS?**

19 **A.** Yes. On January 7, 2011 in Docket No. 2011-20-E, pursuant to S.C. Code Ann.
20 § 58-33-225, DE Carolinas filed an Amended Project Development Application
21 for Approval of Decision to Incur Nuclear Generation Pre-Construction Costs
22 (the "2011 Application").⁴

⁴ The Company sought similar authority from the North Carolina Utilities Commission regarding the North Carolina allocable portion of Lee Nuclear Project development costs.

1 **Q. WHAT DID THE COMPANY REQUEST IN THE 2011 APPLICATION?**

2 A. In the 2011 Application, the Company requested authority to incur additional
3 pre-construction costs of \$229 million through December 31, 2013, for a total
4 of \$459 million (including Allowance for Funds Used During Construction
5 ("AFUDC")) to ensure the Lee Nuclear Project remained on schedule to serve
6 customer needs in the 2021 timeframe. DE Carolinas noted that the
7 environment for planning the Company's system continued to be dynamic and
8 it was reasonable and prudent for the Company to continue developing the Lee
9 Nuclear Project.

10 **Q. DURING THE 2011 PROCEEDING HAD THE COMPANY MADE A**
11 **FINAL DETERMINATION TO CONSTRUCT THE LEE NUCLEAR**
12 **PROJECT?**

13 A. No. Although the Company continued to believe that the Lee Nuclear Project
14 was critical to meet future resource needs, the Company did not make a
15 commitment to build the facility. The Company made clear that to move
16 forward with building the Project, provisions similar to those contained in the
17 BLRA that allow for the recovery of financing costs outside of a rate case would
18 need to be in place in North Carolina. In addition, the COL would need to be
19 in place, and all necessary approvals from state regulators would need to be
20 obtained.

21 In both the 2007 and 2011 applications, the Company stressed that the
22 Lee Nuclear Project would have been the largest single capital project in the
23 history of the Company and the assurance sought by its application was critical

1 to the Company's financial well-being and the ability of DE Carolinas'
2 customers to count on a more diverse, greenhouse gas emission-free, generation
3 source.

4 **Q. WHAT WAS THE OUTCOME OF THE 2011 PROCEEDING?**

5 A. During the 2011 proceeding, DE Carolinas reached a Settlement Agreement
6 with the ORS and other intervenors that provided a constructive approach that
7 would allow DE Carolinas to keep the nuclear option available and maintain
8 the current schedule for obtaining a COL from the NRC, which at the time, was
9 anticipated to be received in 2013. The Settlement Agreement provided pre-
10 authorization that the Company could incur costs of up to \$75 million without
11 AFUDC, not to exceed \$120 million including AFUDC, during the time period
12 of January 1, 2011 through June 30, 2012. Moreover, the Settlement Agreement
13 provided that it was prudent for the Company to continue to incur development
14 costs for the Lee Nuclear Project only to the extent necessary to maintain the
15 current schedule for obtaining a COL to support a commercial operation date
16 for the Project in the 2021-2023 time frame. The parties agreed that the
17 Company must incur only the absolute minimum amount of dollars necessary
18 to keep the nuclear option available and that in any proceeding to recover such
19 costs, the Company must show that the activities it undertook met these
20 requirements.

21 The Company also agreed to provide (a) a monthly report on the status
22 of legislation to allow for recovery of financing costs outside a rate case in
23 North Carolina, (b) a quarterly report on expenditures and AFUDC; and (c) a

1 monthly report on the progress of the Company's negotiations to acquire an
2 interest in the V.C. Summer Units 2 and 3. The Settlement Agreement also
3 provided that DE Carolinas agreed that any change in ownership interest, output
4 allocation, sharing of costs or control, and any future option agreements
5 concerning the proposed Lee Nuclear Project would be subject to prior approval
6 of the Commission. The Commission approved the Settlement Agreement in
7 its entirety and issued an order on July 1, 2011.

8 Q. ARE RECOVERABLE COSTS GREATER THAN THE AMOUNT
9 PREAUTHORIZED BY THE COMMISSION IN THE 2011
10 PROCEEDING?

11 A. Yes. In order to keep the Lee Nuclear Project as an option within the targeted
12 timeframe the Company exceeded the preauthorized spending level and
13 incurred cost after June 30, 2012. At the time that the 2011 Application was
14 approved, DE Carolinas had projected receipt of the COL in 2013 for the Lee
15 Nuclear Project. As I explain later in my testimony, the capital spending activity
16 after 2013 declined substantially as project development activities continued to
17 be significantly limited to only the minimal amount necessary to keep the
18 nuclear option available. As Dr. Diaz will explain in his testimony, several
19 factors, many of which were outside the control of DE Carolinas, led to a longer
20 licensing period than originally projected.

1 Q. PLEASE DISCUSS THE FACTORS THAT SUPPORTED
2 CONTINUATION OF PROJECT DEVELOPMENT ACTIVITIES AND
3 OBTAINING THE COL.

4 A. First, the Project was still shown to be needed by customers. As demonstrated
5 through the IRP process, the Lee Nuclear Project continued to be an economic
6 choice for customers. Over the life of the Lee Nuclear Project, the timeframe
7 for when new nuclear would be needed has necessarily been amended as
8 assumptions in the IRP have been revised. However, up through the 2016 IRP,
9 the Lee Nuclear Project continued to demonstrate its viability as a least-cost
10 carbon free generation option for customers. In addition, one important benefit
11 of DE Carolinas' actions is that having the COL for the Lee Nuclear Project will
12 reduce the lead time required to license new nuclear while at the same time not
13 committing to billions of dollars of project expenditures. By obtaining the
14 license, DE Carolinas has mitigated one of the primary challenges to new
15 nuclear construction in the U.S., which is the time and effort needed to obtain a
16 COL to build and operate a nuclear plant. Having the COL for the Lee Nuclear
17 Project has shortened the total time needed to permit and construct a new
18 nuclear facility, which will benefit customers if nuclear is ever selected in the
19 future to meet customer needs.

20 Secondly, the resources and effort expended at the point the
21 preauthorization amount was reached made it reasonable and prudent for DE
22 Carolinas to continue its efforts to obtain the COL for the Lee Nuclear Project.
23 At the point at which the preauthorized spending level was reached, DE

1 Carolinas had spent significant time and resources to develop the COLA and
2 responded to over 595 requests for additional information from the NRC. The
3 Company was also closely working with the NRC to resolve the remaining
4 outstanding licensing issues and had invested significant time and resources
5 towards that end. The investment of those resources would have been lost had
6 the Project been suspended. In addition, DE Carolinas would have forfeited its
7 priority position in the NRC COLA review process and the NRC's limited
8 resources would have been redirected to other projects. Furthermore, we
9 continued to keep the Commission abreast of the schedule receipt of the COL
10 through the IRP process. Indeed, the schedule for receipt of the COL in 2016
11 is very close to the schedule expectation the Company reported to the
12 Commission in its 2013 IRP. Dr. Diaz will discuss in more detail factors that
13 played into the timing of receipt of the COL. In addition, the bulk of the capital
14 spent towards project development activities declined significantly after 2013
15 as the Company continued to limit spending to those activities that were
16 necessary to obtain the COL and preserve the Lee Nuclear Project as a
17 generation option in the timeframe established in the IRP.

18 **Q. ARE THERE ANY OTHER IMPORTANT FACTORS THAT**
19 **SUPPORTED CONTINUING WITH PROJECT DEVELOPMENT**
20 **ACTIVITIES?**

21 **A.** Yes. The Company's decision to proceed with Project Development activities
22 was also bolstered by the robust environment for licensing that continued in the
23 United States. After the Commission issued its preauthorization order in 2011,

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1 the NRC issued its final rule on the Design Certification Amendment for the
2 AP1000. Later, in 2012, the NRC granted the Alvin W. Vogtle Electric
3 Generation Plant Units 3 and 4 ("Vogtle") Project, which had become the
4 reference COL project, its license. Moreover, at the time the preauthorized
5 spending level was exceeded and even continuing today, other utilities were
6 pursuing COLs and competing for very limited NRC COLA review resources.
7 Both South Texas Project Units 3 and 4 and Levy Nuclear Plant Units 1 and 2
8 were issued COLs in 2016 prior to the receipt of the Lee Nuclear Project COL.
9 And since the Lee Nuclear Project COL was issued, Dominion Virginia Power
10 received a COL for North Anna Unit 3 and Florida Power and Light received
11 COLs for Turkey Point Units 6 and 7. To suspend the pursuit of the COL with
12 the NRC because the preauthorization amount had been reached would have
13 eliminated the benefit of DE Carolinas' efforts to decrease the long lead time
14 for new nuclear plant construction when the Company had already completed a
15 significant portion of the requirements necessary to obtain a COL.

IV. DECISION TO ABANDON THE LEE NUCLEAR PROJECT

16 **Q. WHAT IS THE CURRENT STATUS OF THE LEE NUCLEAR**
17 **PROJECT?**

18 **A.** Since the COL was issued in 2016, risks and uncertainties to initiating
19 construction on the Lee Nuclear Project have become too great and
20 abandonment of the Project as was originally envisioned is the best option for
21 customers. Significant events outside of DE Carolinas' control have occurred

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1 since the issuance of the COL for the Lee Nuclear Project that have made
2 abandonment the appropriate choice at this time.

3 In early 2017, Westinghouse announced that it had suffered significant
4 losses from its AP1000 projects in the U.S. and planned to exit the nuclear plant
5 construction business. On February 14, 2017, Toshiba, the parent company of
6 Westinghouse, announced that it would be taking a \$6.3 billion write down of
7 its Westinghouse nuclear business. Toshiba's total market capitalization at that
8 time was approximately \$8 billion. At the same time, Toshiba announced the
9 resignations of Toshiba's CEO and Westinghouse's Chairman and CEO, and
10 indicated Toshiba's desire to sell all or a part of Westinghouse. On March 29,
11 2017, Westinghouse declared Chapter 11 bankruptcy. Furthermore, additional
12 costs in the billions of dollars and delays were announced for the two AP1000
13 plants in Georgia and South Carolina.

14 Because of the bankruptcy, Westinghouse was unable to proceed with
15 the Engineering, Procurement and Construction contracts it entered to complete
16 the U.S. AP1000 projects, Vogtle Units 3 and 4 in Georgia and the Virgil C.
17 Summer Nuclear Station Units 2 and 3 ("V.C. Summer") in South Carolina.
18 The Vogtle Owners have entered into a Services Agreement with Westinghouse
19 whereby Westinghouse will provide some procurement and engineering support
20 as well as access to the AP1000 intellectual property. The Vogtle Owners
21 entered into a separate construction agreement with Bechtel, a separate
22 contractor, to provide construction services for the Vogtle project. On July 31,

1 2017, the V.C. Summer owners announced their decision to cease construction
2 of the V.C. Summer project.

3 **Q. WHAT IMPACT DID THE WESTINGHOUSE BANKRUPTCY HAVE**
4 **ON THE LEE NUCLEAR PROJECT?**

5 A. The AP1000 technology, which is the design utilized for the Lee Nuclear
6 Project, is owned by Westinghouse. For the development of the U.S. projects,
7 Westinghouse had contracted with other firms to form a consortium to share the
8 financial risk of new nuclear plant construction. The consortium entered into
9 Engineering, Procurement and Construction (“EPC”) Agreements with the
10 owners of the Vogtle and the V.C. Summer projects to construct the plants and
11 turn over operation of the plants to the utility owners upon construction
12 completion. The expectations of a similar EPC contracting structure formed
13 the basis for the pricing, schedule, and risk allocation for the Company’s
14 proposed Lee Nuclear Station included in the Company’s IRP. Over time, the
15 consortium membership changed and eventually Westinghouse acquired the
16 interest of its other unaffiliated consortium partner such that it no longer shared
17 the financial risk with an unaffiliated consortium partner. However,
18 Westinghouse was unable to ultimately bear the financial risk of the losses it
19 sustained on the V.C. Summer and Vogtle projects causing it to file for
20 bankruptcy protection.

21 Westinghouse’s exit from the construction business and bankruptcy in
22 2017 and the subsequent decision to cease construction of the V.C. Summer
23 Project raises significant uncertainty around the cost, schedule, and execution

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1 of construction for future AP1000 nuclear projects. These uncertainties had a
2 direct impact on the ability to initiate construction of the Lee Nuclear Project
3 and contributed to the Company's decision to abandon it.

4 **Q. HAS DE CAROLINAS ABANDONED THE LEE NUCLEAR PROJECT?**

5 A. Yes. On August 25, 2017, the Company filed a letter with the Commission in
6 PSCSC Docket No. 2011-20-E notifying the Commission that it was requesting
7 approval from the NCUC to cancel the Lee Nuclear Project pursuant to N.C.
8 Gen. Stat. § 62-110.7, as a predicate to cost recovery for the project in North
9 Carolina. Shortly thereafter, on September 1, 2017, the Company filed its 2017
10 Annual Plan with this Commission in Docket 2017-10-E explaining that revised
11 projections indicated that new nuclear baseload capacity was needed only under
12 a carbon-constrained scenario with the assumption of no existing nuclear re-
13 licensing. Even in that scenario, the added capacity would not be needed until
14 much later (in the 2031 and 2033 timeframe) than projected in the 2016 IRP.
15 Thus, the Company explained its decision to abandon the Lee Nuclear Project
16 was based on: (1) the very limited circumstances under which the nuclear
17 capacity would ever be needed; (2) the later need dates if those limited
18 circumstances came to pass; (3) the risks resulting from the Westinghouse
19 bankruptcy and decision to exit the nuclear construction business; (4) the
20 substantial cost increases and schedule delays associated with the Vogtle and
21 V.C. Summer projects, and the subsequent V.C. Summer project abandonment.

DIRECT TESTIMONY OF CHRISTOPHER M. FALLON
DUKE ENERGY CAROLINAS, LLC

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1 In its Order Accepting Stipulation, Deciding Contested Issues, and
2 Requiring Revenue Reduction, in Docket Nos. E-7 Sub 819 and E-7, Sub 1146
3 dated June 22, 2018 (the "NC DE Carolinas Rate Case Order"), the NCUC
4 approved the Company's request to cancel the Lee Nuclear Project and
5 permitted recovery of the North Carolina allocable share of the Company's
6 investment in the Lee Nuclear Project with some limited exceptions. In light of
7 its decision to abandon the Lee Nuclear Project, the Company is seeking
8 recovery of the Lee Nuclear Project abandonment costs from this Commission
9 for the South Carolina allocable share of the Company's investment.

10 **Q. IS THE DECISION TO ABANDON THE LEE NUCLEAR PROJECT**
11 **PRUDENT?**

12 **A.** Yes. Given the costs and risks associated with constructing the Lee Nuclear
13 Project that materialized in 2017, DE Carolinas' decision to abandon the project
14 is prudent. Although DE Carolinas received its COL from the NRC, events
15 shortly thereafter caused the Company to re-evaluate its plans and determine
16 that the Project, as originally envisioned, was no longer in the best interest of
17 customers. The uncertainty around future construction arrangements and cost
18 for an AP1000 unit as a result of the Westinghouse bankruptcy has created an
19 unknown cost to construct and higher level of risk to continue the Lee Nuclear
20 Project at this time. These critical factors, combined with projected low natural
21 gas prices for the foreseeable future, and uncertain near- and longer-term carbon
22 emissions costs, render it no longer beneficial to customers to construct and
23 commence operation of the Lee Nuclear Project before the end of the next

1 decade. Given these uncertainties facing the project, DE Carolinas believed it
2 was in its customers' best interests to abandon the project. The Company
3 remains committed to clean power and nuclear energy, and the COL and site
4 preparation work can be leveraged should the need for new nuclear arise in the
5 future. DE Carolinas will continue to monitor the Vogtle Project to evaluate
6 risk and project execution strategies

7 In many ways, DE Carolinas' methodical, deliberate and measured
8 approach to evaluate and pursue new nuclear has provided customers with both
9 the viable option of new nuclear by taking the steps necessary to maintain
10 nuclear as a future option, while also avoiding some of the challenges that have
11 been encountered by early adopting utilities who have already undertaken full
12 construction.

13 **Q. HAS DE CAROLINAS STOPPED PRECONSTRUCTION ACTIVITIES**
14 **ON THE LEE NUCLEAR PROJECT?**

15 A. Yes. No preconstruction work continues. Rather, the only costs that continue
16 to be incurred by DE Carolinas are those costs necessary to maintain the COL
17 and site in order to provide options for customers in the future.

V. COST RECOVERY

18 **Q. HAS THE BLRA BEEN AMENDED SINCE THE COMPANY**
19 **RECEIVED THE LEE NUCLEAR PROJECT DEVELOPMENT**
20 **ORDERS?**

21 A. Yes. Effective July 5, 2018, South Carolina House Bill 4375 amended the
22 BLRA so that the Commission "must not accept a base load review application,

1 nor may it consider any requests made pursuant to Article 4, Chapter 33, Title
2 58 other than in a docket currently pending before the Commission.”⁵ Further,
3 HB 4375 provides that “[t]he provisions of Article 4, Chapter 33, Title 58 are
4 repealed upon the conclusion of litigation concerning the abandonment of V.C.
5 Summer Units 2 and 3.”⁶

6 **Q. HOW DO THE 2018 BLRA AMENDMENTS IMPACT THE LEE**
7 **NUCLEAR PROJECT?**

8 A. While I am not a lawyer, I have been advised that because DE Carolinas does
9 not currently have any requests made pursuant to Article 4, Chapter 33, Title 58
10 pending before the Commission, it is unable to request recovery of the
11 abandoned Lee Nuclear Project preconstruction costs pursuant to S.C. Code
12 Ann. §58-33-225(G). Nevertheless, the Company continues to comply with the
13 requirements of the project development orders issued under the BLRA
14 provisions by filing update reports pursuant to the terms of the Settlement
15 Agreement.

16 **Q. PRIOR TO THE ENACTMENT OF THE BLRA IN 2008, HAD THE**
17 **COMMISSION PREVIOUSLY PERMITTED RECOVERY OF**
18 **ABANDONED PLANT?**

19 A. Yes, I have been advised that prior to the enactment of the BLRA, Commission
20 precedent allowed recovery of prudently incurred abandoned plant cost and that
21 this precedent is still applicable today as an independent basis for recovery

⁵ S.C. Code Ann. § 58-33-220 2.A. (2018).

⁶ S.C. Code Ann. § 58-33-220 2.B. (2018).

1 separate from the recovery provisions previously available to the Company
2 under the BLRA. The Company also appropriately relied upon the
3 Commission's orders in Docket Nos. 2007-440-E and 2011-20-E finding its
4 decision to incur preconstruction costs for the Lee Nuclear Project as prudent.
5 Thus, the Company respectfully requests that the Commission allow it to
6 recover the South Carolina allocable portion of its investment of the Lee
7 Nuclear Project as discussed further below.

8 **Q. WHAT COSTS RELATED TO THE LEE NUCLEAR PROJECT IS THE**
9 **COMPANY SEEKING TO RECOVER IN THIS CASE?**

10 A. The total estimated balance of cost at May 31, 2019 is approximately \$559
11 million for the development of the Lee Nuclear Project. The total estimated
12 balance of \$559 million includes AFUDC through December 31, 2017. The
13 Company is seeking Commission approval to recover the South Carolina retail
14 allocable share of approximately \$125 million of the total system spend,
15 adjusted for non-depreciable land moved to Land held for Future Use. These
16 costs are specifically made up of COLA Preparation, NRC Review and Hearing
17 Fees, Land and Right-of-Way Purchases, Pre-Construction and Site
18 Preparation, Supply Chain, Construction Planning and Detailed Engineering,
19 Operational Planning, Post COL, Allocated amounts and AFUDC. The specific
20 details of actual costs incurred through September 31, 2018 are included in the
21 table below:

Category of Cost	Dollars Expended through 09/30/18 on System-Wide Basis*
COLA Preparation	\$25 Million
NRC Review and Hearing Fees	\$110 Million
Land and Right-of-Way Purchases	\$44 Million
Pre-construction and Site Preparation	\$48 Million
Supply Chain, Construction Planning, and Detailed Engineering	\$53 Million
Operational Planning	\$5 Million
Post COL	\$2 Million
Allocate†	\$23 Million
AFUDC	\$248 Million
Total	\$559 Million

*Details may not add to total due to rounding. The South Carolina allocable share is approximately 24 percent.

†Includes \$638,479 for COL maintenance and project close-out in 2017-18.

1 Company witness Kim H. Smith describes the rate treatment, including the
2 proposed amortization schedule, in her direct testimony filed in this case.

3 **Q. PLEASE DESCRIBE THE COSTS INCURRED AS PART OF THE**
4 **COLA PREPARATION CATEGORY.**

5 A. This category includes costs related to DE Carolinas labor, expenses and
6 contract support for preparation of the COLA tendered to the NRC on
7 December 13, 2007. The NRC determined the application was suitable for
8 review and docketed the application on February 25, 2008.

1 **Q. PLEASE DESCRIBE THE COSTS INCURRED AS PART OF THE NRC**
2 **REVIEW AND HEARING FEES CATEGORY.**

3 **A.** This category includes the cost of the NRC review fees, DE Carolinas labor and
4 expenses, contract labor and legal support required to support the NRC review
5 of the Lee Nuclear Station COLA, and preparation for the Advisory Committee
6 on Reactor Safeguards Subcommittee Hearing. This category also includes
7 interactions with South Carolina Department of Health and Environmental
8 Control and the U.S. Army Corps of Engineers ("USACE"), as required to
9 move the environmental permit applications forward. The Lee Nuclear Project
10 received the National Pollutant Discharge Elimination System Operations
11 permit on July 17, 2013. The Final Environmental Impact Statement was issued
12 by the NRC on December 23, 2013, and the 401 Water Quality Certification
13 was issued on January 2, 2014. The Final Environmental Impact Statement
14 prepared by the U.S. Forest Service to support mitigation activities in Sumter
15 National Forest was issued on December 5, 2014. The Lee Nuclear Station
16 received its USACE 404 Permit on September 29, 2015.

17 **Q. PLEASE DESCRIBE THE COSTS INCURRED AS PART OF THE**
18 **LAND AND RIGHT-OF WAY PURCHASES CATEGORY.**

19 **A.** This category includes the purchase of land required for the Lee Nuclear Project
20 site and rail rights-of-way. This category also includes the cost of purchasing
21 additional land for a supplemental cooling pond in event of severe drought, as
22 well as costs for surveying the selected transmission right-of-way.

1 **Q. PLEASE DESCRIBE THE COSTS INCURRED AS PART OF THE PRE-**
2 **CONSTRUCTION AND SITE PREPARATION CATEGORY.**

3 A. This category includes site activities to both maintain the site and prepare the
4 site for construction. Site preparation activities included: dewatering and
5 cleanup of the excavated area, site remediation activities required to identify
6 and properly dispose of hazardous wastes, and costs associated with the
7 demolition and removal of unusable structures. Necessary maintenance of
8 existing rail bed and required Make-up Pond B spillway repair were completed.
9 Engineering of offsite infrastructure for potable water, sewer, and rail spur, and
10 geotechnical evaluations (needed for engineering) have been completed.
11 Engineering for bringing communications to the site is also included in this
12 category. Engineering of necessary traffic improvements was brought to 85
13 percent completion by December 2013. Ongoing and continuing activities
14 include: site security, utilities and miscellaneous site maintenance.

15 **Q. PLEASE DESCRIBE THE COSTS INCURRED AS PART OF THE**
16 **SUPPLY CHAIN, CONSTRUCTION PLANNING AND DETAILED**
17 **ENGINEERING CATEGORY.**

18 A. This category includes activities associated with working with the AP1000
19 consortium to negotiate an EPC agreement. Negotiations in 2008 did not result
20 in an executed contract because DE Carolinas was unable to come to terms on
21 a number of issues, most prominently cost and risk sharing. After the EPC
22 negotiations broke down, DE Carolinas decided to hold off on future EPC
23 discussions until after receipt of the COL when the project schedule could be

1 better defined. In preparation for future EPC negotiations and to better define
2 the project scope and reduce risk for customers, conceptual site-specific
3 engineering and construction planning activities necessary to develop a
4 complete project definition were continued and are included in this category.
5 Continuing construction planning activities serve to further develop
6 construction plans and keep the construction plans in line with the latest
7 engineering. Detailed site-specific engineering began in January 2011 and was
8 brought to 70 percent completion in December 2013. Commercial building
9 design activities started in June 2012, and design of the first six commercial
10 buildings was completed in December 2013. These activities were necessary
11 to preserve the on-line date based on the anticipated need identified for the Lee
12 Nuclear Project in the DE Carolinas IRP.

13 **Q. PLEASE DESCRIBE THE COSTS INCURRED AS PART OF THE**
14 **OPERATIONAL PLANNING CATEGORY.**

15 A. This category includes activities associated with emergency planning ("EP"),
16 operator and plant staff training, including costs associated with the Knowledge
17 and Abilities Catalog, required for operator license examinations for AP1000
18 plants, and the standardization of the nomenclature in the Westinghouse Master
19 Equipment List, supporting operations program development, such as Quality
20 Assurance Program, and the review of approximately 500 procedures. In 2011,
21 the NRC issued a final rule (76 FR 72560) amending certain EP requirements
22 in the regulations that govern domestic licensing of production and utilization
23 facilities (the "EP Final Rule"). The operational planning team was instrumental

1 in developing the DE Carolinas response to the EP Final Rule and these costs
2 are included in this category. The training materials, operational programs, and
3 operating procedures are all being developed in concert with other AP1000
4 utilities within the AP1000 Group LLC ("APOG LLC") framework. APOG
5 LLC was established for the purpose of providing technical, engineering and
6 procurement support services to the members and their licensing, development
7 and construction of AP1000 power plants. APOG LLC was the means to share
8 the cost of engineering and licensing activities between members to lower the
9 overall cost for each member. The Operational Planning category also includes
10 generation of administrative procedures that must be in place upon receipt of
11 COL from NRC.

12 **Q. PLEASE DESCRIBE THE POST COL CATEGORY.**

13 A. As previously discussed, the COL was received in December 2016. Design
14 finalization and first-of-a-kind construction issues at V. C. Summer and Vogtle
15 have required Westinghouse to make numerous changes to the AP1000 design.
16 Design changes continue to be issued as the lead plants advance toward
17 completion. Submittal of an annual FSAR update and recurring regulatory
18 reporting are required to maintain the COL.

19 **Q. PLEASE DESCRIBE THE ALLOCATE CATEGORY.**

20 A. This new category of cost relates to labor burdens and allocated labor costs. In
21 prior reporting this category had been manually spread to create cost status
22 reports. DE Carolinas determined that it is more accurate to show these charges
23 in a separate bucket and began reporting in this manner on November 21, 2017.

1 **Q. PLEASE DESCRIBE THE AFUDC CATEGORY.**

2 A. AFUDC costs are the financing costs (both debt and equity) on the capital
3 dollars incurred on the Project once the Project costs began being recorded to
4 FERC Account 107, Construction Work in Process.

5 **Q. WHAT COSTS HAS THE COMPANY INCURRED FOR THE LEE**
6 **NUCLEAR PROJECT?**

7 A. DE Carolinas has incurred a total of approximately \$558 million in cost for
8 project development activities through September 30, 2018. As discussed in
9 DE Carolinas Witness Kim H. Smith's testimony, DE Carolinas is requesting
10 Commission approval of the South Carolina allocable share of the Lee Nuclear
11 Project spend through September 30, 2018 including projected costs through
12 May 31, 2019, which total approximately \$518 million after non-depreciable
13 land is moved to Land held for Future Use.

14 **Q. WHAT COSTS DID THE COMPANY INCUR PURSUANT TO THE 2008**
15 **AND 2011 LEE NUCLEAR PROJECT DEVELOPMENT ORDERS?**

16 A. Of the total \$350 million authorized by the Commission through the 2008 and
17 2011 Lee Nuclear Project Development Orders, DE Carolinas incurred
18 approximately \$251 million during the authorized time periods in the orders.

19 **Q. PLEASE EXPLAIN ANY COSTS INCURRED OUTSIDE THE**
20 **TIMEFRAMES AUTHORIZED IN THE LEE NUCLEAR PROJECT**
21 **DEVELOPMENT ORDERS.**

22 A. In 2010, the Company incurred approximately \$36 million of Lee project
23 development costs. As previously explained, DE Carolinas requested approval

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1 of its decision to incur these costs in its 2011 Application; however, the
2 Company reached a Settlement Agreement with ORS and some of the
3 intervenors, and the Commission approved the Company's decision to incur
4 costs, not to exceed \$120 million including AFUDC, during the time period of
5 January 1, 2011 through June 30, 2012. From July 1, 2012 to September 30,
6 2018, DE Carolinas incurred approximately \$271 marmillion in additional Lee
7 Nuclear Project development costs.

8 **Q. DID DE CAROLINAS TAKE STEPS TO LIMIT WORK PERFORMED**
9 **ON THE PROJECT TO THE MINIMAL AMOUNT NECESSARY TO**
10 **KEEP THE NUCLEAR OPTION AVAILABLE?**

11 A. Yes. As a result of the Commission's approval of the 2011 Application, DE
12 Carolinas began limiting its activities to only those activities and costs
13 necessary to obtain the COL and to keep the nuclear option available in the
14 targeted timeframe identified in the IRP. The Company did not order equipment
15 and wound down non-essential site-specific work, and construction planning
16 activities. The Company completed its contractual commitments in areas that
17 were no longer necessary and deliberately narrowed the scope of work to reduce
18 costs. Rather than immediately terminate contracts with contractors and incur
19 termination costs, the Company wound down contracts in an orderly manner
20 that preserved the work in a position to efficiently resume at a later date. The
21 Company's intent was to reduce costs to only those necessary, while preserving

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1 the ability to resume work once the COL was received and the Company
2 decided to move forward with the project.

3 **Q. WERE ALL THE COSTS INCURRED FOR THE LEE NUCLEAR**
4 **PROJECT REASONABLE AND PRUDENTLY INCURRED PROJECT**
5 **DEVELOPMENT COSTS?**

6 A. Yes. As further discussed and explained also in the testimony of DE Carolinas
7 Witness Nils J. Diaz, the costs incurred to obtain a COL for the Lee Nuclear
8 Project were reasonably and prudently incurred project development costs
9 undertaken to ensure a diverse, cost effective and reliable supply of energy for
10 DE Carolinas' retail customers.

11 **Q. HAVE THERE BEEN ANY OTHER ANALYSES OR FINDINGS**
12 **REGARDING THE PRUDENCE OR REASONABLENESS OF THE**
13 **LEE NUCLEAR PROJECT DEVELOPMENT COSTS?**

14 A. Yes. The NCUC Public Staff reviewed the Lee Nuclear Project development
15 costs in connection with pending rate proceedings in North Carolina. There,
16 the Public Staff retained Global Energy to assist in the review of those costs and
17 I have included their final report to the Public Staff as Exhibit 1 to my testimony.
18 The Public Staff concluded that costs incurred by DE Carolinas in pursuit of the
19 COL, including costs associated with pre-construction and site development,
20 land and right-of-way purchases, supply chain, construction planning and
21 detailed engineering, operational planning, and post-COL costs were
22 reasonable and prudent with little exception.

23

VI. CONCLUSION

- 1 Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?
- 2 A. Yes.

1 BY MR. MARZO:

2 Q Dr. Diaz, would you please give your summary of your
3 testimony?

4 A [DIAZ] Sure.

5 Mr. Chairman, Commissioners, it is my distinct
6 privilege to testify before the South Carolina Public
7 Service Commission.

8 The purpose of my direct testimony is to review the
9 reasonableness and prudence of the strategy and efforts
10 of Duke Energy Carolinas – here called “the company” or
11 “DE Carolinas” – to secure a combined construction and
12 operating license, or COL, for the Lee nuclear project.

13 I conducted an overall review of the decision-
14 making process throughout the project and examined
15 documentation related to significant Lee COL application
16 issues and events, using management strategies,
17 schedules, and COL review matters as performance
18 indicators. I determined that DE Carolinas' decisions
19 and actions to take a stepwise approach to licensing and
20 managing the Lee nuclear project and its decision to
21 extend the units' target operation dates were reasonable
22 and consistent with industry best practice.

23 The company identified the need to begin planning
24 for nuclear through its integrated resource planning –
25 IRP – process in its 2005 and 2006 annual plans. At

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1 the time, the nuclear industry was experiencing a strong
2 renewal due to improved regulatory stability, improved
3 technology, and improved economic factors. Accordingly,
4 DE Carolinas decided to pursue new nuclear in this
5 favorable environment to ensure the availability of
6 cost-competitive, reliable, and predictable electricity
7 generation for its customers.

8 DE Carolinas submitted a COL application to the
9 Nuclear Regulatory Commission – NRC – for two AP1000
10 reactors on December 13, 2007. The NRC docketed the
11 company's COL application in February 2008.

12 Concurrently, DE Carolinas established a project
13 management organization for the Lee nuclear project to
14 actively pursue the COL and to conduct those activities
15 necessary to maintain the viability of the project. To
16 ensure full disclosure of the plans and activities and
17 to address cost-recovery needs, DE Carolinas applied
18 from the Commission – applied for approval, excuse me,
19 from the Commission, relating to costs incurred to
20 develop the Lee nuclear project. After an extensive
21 review of DE Carolinas' licensing plan for the Lee
22 nuclear project, the Commission issued two separate
23 orders approving project-development cost recovery.

24 Importantly, the company employed a licensing-first
25 strategy and began the licensing process early enough to

1 accommodate potential delays in order to exercise the
2 license when it is most beneficial to DE Carolinas'
3 customers. The company continued to make cost-conscious
4 decisions, including deferring long-lead procurement
5 decisions and costly site work. The company did not
6 enter into an engineering, procurement, and construction
7 contract. In fact, the company followed the three
8 baseline actions recommended by the 1992 Energy Policy
9 Act: first, licensing decisions are to be finalized
10 before major construction begins; second, utilities
11 would order plants after regulatory and financial risks
12 are mitigated by satisfactory completion of the new
13 licensing process; and, third, the use of standardized,
14 safer reactor designs are encouraged.

15 My testimony also explains that DE Carolinas faced
16 numerous issues during the licensing process that
17 impacted the timing for the issuance of the Lee COL.
18 The major issues that impacted the Lee COL review
19 include delays related to: the Yucca Mountain Review,
20 Waste Confidence Rule, Fukushima Daiichi accident,
21 Seismic Source Characterization for the Central and
22 Eastern United States, and the implementation of the new
23 10 CFR Part 52 licensing. My testimony provides
24 detailed facts and circumstances surrounding each of
25 these delays. The issues, in their aggregate, resulted

1 in a licensing process taking significantly longer than
2 originally anticipated for the Lee nuclear project, as
3 well as other projects. It would be demanding to
4 license a power reactor under normal circumstances, but
5 the period between 2008 and 2016 was especially
6 demanding. The NRC ultimately issued the Lee COL on
7 December 19, 2016.

8 Finally, my testimony discusses the near-term
9 impacts of the Westinghouse bankruptcy and overall
10 reorganization. I explain that, with Westinghouse
11 exiting the construction business, it will be important
12 for DE Carolinas to evaluate project execution
13 strategies for new nuclear and establishing how
14 engineering, procurement, and construction will be
15 undertaken to adhere to a reliable cost and schedule.

16 Ultimately, I concluded that DE Carolinas'
17 decisions and actions to take a stepwise approach to
18 licensing and managing the Lee nuclear project and its
19 decision to extend the project's target operation dates,
20 as established by the IRPs, were reasonable and prudent,
21 and consistent with industry best practices. The COL
22 has intrinsic value by providing the capability of
23 deploying a nuclear power plant when it is most
24 beneficial and – I'm sorry, there's something wrong in
25 here – when it's most beneficial and can operate the

1 plant for a licensed life of 40 years, with the
2 possibility of additional license extensions. Customers
3 should benefit from the Lee COL and project development
4 for a long time after its deployment.

5 This concludes my testimony.
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23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED DIRECT TESTIMONY OF NILS J.
25 DIAZ, Ph.D., FOLLOWS HEREINAFTER]

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PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2018-319-E

In the Matter of:	)	
	)	DIRECT TESTIMONY OF
Application of Duke Energy Carolinas, LLC	)	NILS J. DIAZ, PhD
for Adjustments in Electric Rate Schedules and	)	FOR DUKE ENERGY
Tariffs	)	CAROLINAS, LLC

I. INTRODUCTION

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Nils J. Diaz and my business address is 3414 West Gables Ct.,
3 Tampa, Florida, 33609.

4 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

5 A. I am employed by The ND2 Group, LLC ("ND2"), as its Managing Director.
6 ND2 is a policy advising and consulting group with a strong focus on nuclear
7 energy matters. ND2 presently provides expert advice for clients in the areas
8 of nuclear power licensing and deployment, high-level radioactive waste
9 disposal, processing and storage issues, and advanced security systems.

10 **Q. PLEASE SUMMARIZE YOUR EDUCATION, PROFESSIONAL**
11 **QUALIFICATIONS, AND OTHER INDUSTRY EXPERIENCE AND**
12 **AFFILIATIONS.**

13 A. I hold a Bachelor of Science Degree in Mechanical Engineering from the
14 University of Villanova, Havana, and MS and PhD degrees in Nuclear
15 Engineering Sciences from the University of Florida. I presently conduct
16 policy advising and consulting for the U.S. government, foreign governments,
17 and industry. I hold board memberships in private institutions and the position
18 of Professor Emeritus of Nuclear Sciences at the University of Florida. I
19 served as a Commissioner on Florida's Energy and Climate Commission from
20 2008 to 2010, recently chaired the ASME Presidential Task Force on
21 Response to Japan Nuclear Power Plant Events, and chaired two major
22 reviews of the Safety Culture and Quality Assurance Program for the Hanford

1 Waste Treatment Plant. I previously served as the Chairman of the United
2 States Nuclear Regulatory Commission ("NRC") from 2003 to 2006 and as
3 Commissioner from 1996 to 2006. Prior to my appointment to the NRC, I was
4 the Director of the Innovative Nuclear Power and Propulsion Institute for the
5 Ballistic Missile Defense Organization of the U.S. Department of Defense
6 from 1985 to 1996. I have testified as an expert witness to the U.S. Senate and
7 House of Representatives on multiple occasions over the last thirty years.
8 Additional details on my background and experience are provided in my
9 summary resume, which is attached as Exhibit NJD-1.

10 **Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?**

11 A. Yes, I have included three exhibits:

12 Exhibit NJD-1 – Summary Resume of Nils J. Diaz, PhD;

13 Exhibit NJD-2 – Expected New Nuclear Power Plant Applications (2008); and

14 Exhibit NJD-3 – U.S. NRC: COL Applications Received through June 15,
15 2017.

16 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?**

17 A. No.

18 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

19 A. The purpose of my testimony is to review the reasonableness and prudence of
20 the strategy and efforts of Duke Energy Carolinas, LLC ("DE Carolinas" or
21 the "Company") to obtain a combined license ("COL") for the William States
22 Lee III Nuclear Station Units 1 and 2 (the "Lee Nuclear Project").

1 Q. PLEASE DESCRIBE YOUR PERTINENT EXPERIENCE FOR
2 REVIEWING DE CAROLINAS' APPROACH TO THE LICENSING
3 OF THE LEE NUCLEAR PROJECT.

4 A. From my tenure as an NRC Commissioner starting in 1996, I have been
5 evaluating licensing issues and applications submitted to the NRC,
6 specifically issues related to the new licensing process under 10 CFR Part 52
7 whereby utilities are issued a COL before construction on the plant begins. I
8 reviewed Westinghouse's Advanced Passive ("AP") safety designs, beginning
9 with the AP600. The AP600 was the first of its kind, a standardized passive
10 safety reactor. Its final Design Certification was issued in March 2000. I am
11 thoroughly familiar with the Westinghouse AP1000 new nuclear plant design,
12 reviewing Westinghouse's applications and the NRC staff safety reviews for a
13 period of ten years, including the AP600 reviews. I was directly involved in its
14 Design Certification process and signed its first Final Design Approval
15 (Revision 15) in March 2006. The AP1000 Design Certification is referenced
16 by DE Carolinas in its COL Application ("COLA"). Furthermore, I am
17 cognizant of the 10 CFR Part 52 licensing process, as used by DE Carolinas to
18 obtain the COL for the Lee Nuclear Project. In addition to my direct
19 experience with the AP1000 design and NRC processes, I also participated in
20 Florida Power & Light's ("FP&L") applications to the Florida Public Service
21 Commission ("FPSC") to obtain necessary approvals for the development of
22 two AP1000 reactors at FP&L's Turkey Point site ("Turkey Point Units 6 and
23 7"). I began working with FP&L to assemble the need determination in 2007

1 for the FPSC and continued contributing to FP&L's annual nuclear cost
2 recovery proceedings until 2015. During my nine years working with FP&L, I
3 provided expert testimony and testified before the FPSC annually, covering
4 issues related to FP&L's licensing requirements, submittals to the NRC and
5 other agencies, the overall environment for licensing new nuclear power
6 plants and power upgrades, and specific issues impacting the pursuit of the
7 COL for Turkey Point Units 6 & 7. I reviewed the reasonableness and
8 prudence of the management strategy and activities, as well as the associated
9 costs.

10 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

11 A. The remainder of my testimony is organized as follows:

- 12 II. THE 1990'S: STEPPING STONES TO NEW REACTOR
13 DEVELOPMENT AND LICENSING
- 14 III. 2000-2010: CONFLUENCE OF CONTRIBUTING FACTORS TO
15 NEW NUCLEAR POWER DEVELOPMENT
- 16 IV. ANALYSIS OF DE CAROLINAS' DECISION TO PURSUE A COL
17 FOR LEE NUCLEAR PROJECT
- 18 V. OBSTACLES TO LICENSING THE LEE NUCLEAR PROJECT ON
19 SCHEDULE
- 20 VI. REVIEW OF DE CAROLINAS COL AND PROJECT-RELATED
21 DECISIONS AND COSTS
- 22 VII. CONCLUSIONS

1 **II. THE 1990'S: STEPPING STONES TO NEW REACTOR**
2 **DEVELOPMENT AND LICENSING**

3 **Q. WHAT WERE THE FACTORS THAT CONVERGED TO SLOW**
4 **DOWN THE CONTINUING DEVELOPMENT OF NUCLEAR**
5 **ELECTRICITY GENERATION IN THE UNITED STATES BY THE**
6 **EARLY 1990S?**

7 **A. By the early 1990s, the road to new nuclear power development had been**
8 b hindered by a combination of negative factors, commencing with the financial
9 and market disruptions from the "oil embargos," the Three Mile Island
10 accident in 1979, and the convergence of high construction costs, double digit
11 inflation and interest rates, decreasing load demand, significant construction
12 delays, regulatory uncertainty, and relatively poor economic performance of
13 the operating nuclear plants.

14 **Q. WHAT FACTORS CHANGED TO IMPROVE THE DEVELOPMENT**
15 **OF NUCLEAR POWER?**

16 **A. Several factors were improving by the early 1990s, starting with an effort by**
17 the NRC to establish a more predictable and less onerous licensing process for
18 nuclear power plants and followed by improvements in nuclear plant
19 performance and economics, more advanced nuclear technology, and
20 increased financial stability and sustained economic growth for the nation.
21 The NRC produced in 1989 its first major change in new reactor licensing by
22 promulgating the 10 CFR Part 52 Rule ("Part 52"), which was focused on
23 decreasing financial risk and standardizing the design and construction of

1 nuclear power plants. The Part 52 rule was then codified in Section 185(b) of
2 the Atomic Energy Act (AEA) by the Energy Policy Act of 1992 ("EPAC-
3 92"). The EPAC-92 was promulgated by the United States Congress to
4 establish a more effective framework for the development of nuclear power,
5 anchored in standardized, safer, more reliable nuclear reactors, implementing
6 strategies to minimize financial and regulatory risk. The resulting strategies
7 included: 1) licensing decisions are to be finalized before major construction
8 begins; 2) utilities would order their plants after regulatory/financial risks are
9 mitigated by satisfactory completion of the new licensing process; 3)
10 standardized, safer reactor designs are to be encouraged; and 4) limited site
11 work could begin when warranted by effective project management.

12 **Q. WHAT IS PART 52, AND HOW WAS IT SUPPOSED TO**
13 **CONTRIBUTE TO REGULATORY LICENSING EFFECTIVENESS**
14 **AND PREDICTABILITY?**

15 A. Part 52 – LICENSES, CERTIFICATIONS, AND APPROVALS FOR
16 NUCLEAR POWER PLANTS is a newer reactor licensing process that can
17 be substituted for the licensing process specified in Part 50 – DOMESTIC
18 LICENSING OF PRODUCTION AND UTILIZATION FACILITIES. In other
19 words, Part 50 continues to be the main regulation for nuclear reactors, but
20 issues specifically dealing with the licensing of new reactors can be treated
21 under Part 52. Part 52 shifts the burden and uncertainty of NRC licensing to
22 the front end of the development process. Part 52 is a powerful addition to
23 nuclear power plant regulations that authorizes construction and conditional

1 operation after a comprehensive review, in order to resolve many of the
2 scheduling problems and financial risks encountered with the Part 50 licensing
3 process. On the other hand, under the old Part 50 reactor licensing, the
4 applicant would not be issued an operating license until after the nuclear plant
5 is constructed and certified to comply with assurance of protection of public
6 health and safety. The most beneficial use of Part 52 is when two of its major
7 components are used together: the Design Certification and the COL. The
8 most important component of Part 52 is the COL because it is the only license
9 that allows plant construction and operation. The Part 52 COL allows early
10 resolution of safety and environmental issues before the plant is constructed.
11 When the COL is paired with a certified design, the reactor safety issues
12 resolved by the design certification rulemaking process are not reconsidered
13 during the COL review and are, therefore, not subject to adjudication during
14 the COL licensing process. Moreover, the Part 52 licensing process allows for
15 full public participation, so that the issues associated with the design and site
16 can be resolved before construction begins.

17 **III. 2000-2010: CONFLUENCE OF CONTRIBUTING FACTORS TO NEW**
18 **NUCLEAR POWER DEVELOPMENT**

19 **Q. WHAT WERE THE FACTORS INFLUENCING NUCLEAR POWER**
20 **DEVELOPMENT FROM 2000 TO THE ENACTMENT OF THE 2005**
21 **ENERGY POLICY ACT?**

22 **A.** The operating nuclear industry had turned the corner by the turn of the
23 century, with capacity factors of about 90 percent and low production costs.

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1 The nuclear vendors were proposing Generation III+ reactors that exhibit
2 additional inherent safety and simplicity in construction and operation, with
3 Westinghouse applying in 1996 for design certification of its AP600 passive
4 safety features reactor and then introducing the upgraded AP1000 in 2002.
5 The NRC regulatory framework was more stable and dependable, reactor
6 licensing risk appeared to be reduced by the addition of Part 52, and overall
7 regulatory risk was decreasing. The environmental issues were favoring
8 nuclear power due to its environmentally benign footprint, near zero carbon
9 emissions, and effective carbon abatement. Supplies of uranium were well
10 established, diverse, and economical. The security issues raised by the
11 9/11/2001 terrorist attacks were well resolved by the NRC and the nuclear
12 power industry. Environmental considerations and the 2005 Clean Air rules
13 resulted in increased scrutiny and challenges to the continued dominance of
14 coal as the primary electricity producer. Increasing dependence on natural gas
15 was being questioned for its increasing price and especially for price volatility.
16 The electrical industry was emphasizing diversity and reliability for new base-
17 load capacity additions that would be strong contributors to long-term
18 electrical and gas price stabilization. Nuclear power appeared to fit the need,
19 and the political establishment responded with the Energy Policy Act of 2005
20 ("EPAC-05"), which contained a series of incentives for nuclear power
21 development.

1 **Q. HOW DID THE NUCLEAR POWER INDUSTRY RESPOND TO THE**
2 **CONFLUENCE OF FACTORS FAVORING DEVELOPMENT?**

3 A. The nuclear power industry responded by applying for new reactor licenses,
4 proposing the subsequent construction / operation of many new units, and
5 submitting the first new nuclear plant applications in three decades. Utilities
6 began working on license applications in 2005, mostly for Part 52 licensing,
7 with docketing at the NRC beginning in 2007. Five applications were
8 docketed in 2007, including DE Carolinas' application for the Lee Nuclear
9 Project. The industry accelerated planned nuclear development in 2008, with
10 an additional nineteen units applying for COLs, as shown on Exhibit NJD-2,
11 U.S. NRC: Expected New Nuclear Power Plant Applications (September 4,
12 2008). By the end of calendar year 2009, twenty companies had submitted
13 applications for thirty-one new nuclear units. Also, most of the operating
14 nuclear units in the country applied for twenty-year license extensions and
15 committed to substantial power upgrade investments. It is apparent that
16 utilities with significant nuclear power plant electrical generation experience
17 had studied the marketplace, technology, and regulatory framework and
18 decided that adding base-load nuclear power was in the best interest of their
19 customers. The majority of companies considering new nuclear are in the
20 Eastern Seaboard, where load demand projections, nuclear experience, and
21 economics were favorable to nuclear power expansion.

1 **Q. DID THE FAVORABLE ENERGY SCENARIO AND NUCLEAR**
2 **EXPANSION CONTINUE THROUGH THE END OF THE DECADE**
3 **AND BEYOND?**

4 **A.** No. There were multiple emerging energy, economic, and political factors that
5 impacted the nascent nuclear expansion. The so-called "Great Recession"
6 started in late 2007 and technically ended in June 2009. However, its impact
7 on the nation's economics and energy development continued. One of the
8 major impacts of the Great Recession was the downturn of natural gas demand
9 and prices, which later coupled with the significant increase in the availability
10 of natural gas due to the introduction of hydraulic fracturing methods,
11 resulting in historically cheap and less volatile natural gas prices. Natural gas
12 prices had peaked in August 2005 at over \$18 per thousand cubic feet
13 ("Mcf"). Prices stood at \$14.76 per Mcf in June 2008 and were down to \$2.75
14 per Mcf in August 2009. Furthermore, the price has hovered in the range of \$3
15 to \$5 for the last seven years. The overall impact on the nation, especially on
16 the electricity generation market, has been dramatic. The extreme volatility of
17 natural gas prices had been a serious economic concern during the 2000-2010
18 decade, and concerns linger. However, the reality of much lower priced
19 natural gas, often predicted to remain below \$5 per Mcf for a couple of
20 decades, became a principal force in the electricity marketplace. Also, it
21 should be remarked that the issue of carbon regulatory uncertainty, especially
22 the potential for carbon tax, cap and trade, and other forms of regulating CO₂
23 that have been under consideration for years, has affected energy cost

1 projections. Nuclear power has been expecting to benefit from any form of
2 carbon regulation or taxation, but none has materialized. Moreover, the energy
3 scenario changed in a very short period of time. With natural gas prices down
4 and fluctuating within a reasonable range and production up about 50 percent
5 due to advanced hydraulic fracturing, natural gas became the fuel of choice
6 over coal. In addition, wind and solar power continued to make inroads as
7 sustainable electrical energy choices. The need for increased national security,
8 energy independence, and environmental stewardship contributed to the so-
9 called "American Energy Renaissance." By 2010 and beyond, the abundance
10 of cheap natural gas, aided by the surge of wind and solar power, was a
11 dominant force in the electricity marketplace. New nuclear power
12 development slowed when confronted with those issues and matters particular
13 to nuclear power deployment, especially the long time required for licensing
14 and construction. However, utilities with the strongest cases for nuclear power
15 deployment continued to pursue plant licensing to ensure the option for base-
16 load generation capacity, other than gas, was available when needed.

17 **Q. HOW DID THE NUCLEAR POWER INDUSTRY REACT TO THE**
18 **NEW ELECTRICITY MARKETPLACE EMERGING IN THE U.S.?**

19 A. The reaction of the nuclear industry, as shown in Exhibit NJD-3, U.S. NRC:
20 COL Applications Received through June 15, 2017, was mixed. Two primary
21 paths were chosen by the nuclear utilities that had applied for a license to the
22 U.S. NRC. Fourteen applicants decided to stop / suspend their license
23 applications, and fourteen applicants continued the effort to obtain a license

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1 and conduct those activities necessary to preserve the option to build and
2 operate a nuclear power plant. The fourteen applicants suspending their COL
3 applications included merchant plants, which primarily existed in uncertain
4 and volatile electrical markets, some with COLAs referencing very complex
5 reactor designs without Design Certifications (the European Nuclear Reactor,
6 EPR). The fourteen applicants continuing to pursue the COL were in stable
7 electrical marketplaces with significant, dependable loads. The first two COL
8 recipients, Georgia Power and South Carolina Electric and Gas ("SCE&G"),
9 started nuclear construction for two units each immediately after receiving
10 their licenses, on 2/09/2012 and 3/30/2012, respectively, and right after the
11 AP1000 Design Certification Amendment was issued in December 2011.
12 Another six applicants have received a COL, with FP&L receiving the final
13 pending COL for Turkey Point Units 6 & 7 in April 2018. A total of ten
14 nuclear units maintain active COLs. Four nuclear units received COLs and
15 subsequently terminated their licenses. While the V.C. Summer COLs remain
16 active, construction has been cancelled for the two V.C. Summer AP1000
17 units. The strategy employed by the eight utilities (fourteen units) that pursued
18 the COLs and the capability to construct / operate nuclear power plants within
19 the framework established by Part 52 has been called the "value option." A
20 COL, obtained after a long and exhaustive review process, is very valuable.
21 Its value is based on the fact that securing a license to construct / operate a
22 nuclear power plant enables the utility to select the time for construction that
23 is most beneficial to consumers without incurring the large expenditures

1 required for construction. The value intrinsic to the COL and the project
2 development effort, including the importance of a site licensed for large power
3 generation, is preserved for when the marketplace and financial conditions are
4 favorable to exercise the option.

5 **IV. ANALYSIS OF DE CAROLINAS' DECISION TO PURSUE A COL**
6 **FOR LEE NUCLEAR PROJECT**

7 **Q. WHAT WERE THE NUCLEAR MARKETPLACE CONDITIONS**
8 **SPECIFICALLY FAVORING PURSUING A COL BY DE CAROLINAS?**

9 A. At the time of DE Carolinas' application, the nuclear industry was
10 experiencing a renewal due to a number of factors, including regulatory
11 stability, safer and simpler reactor designs, projected increased energy
12 demand, high cost and high variability of natural gas prices, economic
13 incentives from EPAC-05, and a renewed focus on reducing carbon emissions.
14 Fuel diversification was important to utilities as a risk reduction strategy, as
15 was the long-term predictability of nuclear costs. As extensively discussed in
16 the previous section, there were multiple factors that made nuclear power a
17 viable and economic option to DE Carolinas when the company decided to
18 pursue new nuclear. Foremost, the selected Part 52 licensing process decreases
19 the risk by enabling the deferment of major investments until after issuance of
20 a COL. In simple terms, DE Carolinas did not have to make major
21 investments for nuclear power plant construction until they had a COL from
22 the NRC. The Lee Nuclear Project was being developed following well-
23 established management strategies to minimize financial risk to its customers.

1 **Q. WHAT SPECIFIC REGULATORY FACTORS CONTRIBUTED TO**
2 **THE DE CAROLINAS DECISION TO PURSUE A COL?**

3 A. By mid-2005, the NRC had done extensive work to be able to docket
4 applications for a COL under Part 52. The NRC-published schedule for a COL
5 license review was forty-two months. A timeframe of forty-eight months was
6 considered very probable. The NRC was quickly expanding its staff to support
7 the expected new applications and most of the supporting regulatory
8 framework had been or was being updated. The best approach to using the
9 new Part 52 licensing process and its risk-reducing features is to reference a
10 Standard Design Certification in a COL. This approach became available in
11 January 2006, when the NRC's Design Certification for Westinghouse's
12 AP1000 reactor was issued by rulemaking. The establishment of the AP1000
13 Design Certification provided the needed regulatory anchor to the COL,
14 enabling the full utilization of Part 52 reactor licensing. Also, the enacted
15 EPAC-05 included loan guarantees and production tax credits for a few new
16 nuclear plants.

17 **Q. WHAT INITIAL DECISIONS WERE MADE AND WHAT ACTIVITIES**
18 **WERE CONDUCTED BY DE CAROLINAS REGARDING THE**
19 **LICENSING OF THE LEE NUCLEAR PROJECT?**

20 A. DE Carolinas decided to pursue the preparation of a COLA in 2005 and
21 submitted it to the NRC on December 13, 2007. The application referenced
22 Revision 16 of the AP1000's Design Control Document ("DCD") of 2007. DE
23 Carolinas' COLA was found by the NRC staff to be suitable for review and

1 docketed on February 25, 2008. DE Carolinas established a project
2 management organization to actively pursue the COL and to conduct those
3 activities necessary to maintain its viability.

4 In order to ensure full disclosure of its activities and plans, and to
5 address their cost recovery needs, DE Carolinas applied to the Public Service
6 Commission of South Carolina ("PSCSC") for approval of its decision to
7 incur pre-construction costs. The PSCSC, after its requisite extensive review
8 of DE Carolinas' proposed licensing plan for the Lee Nuclear Project and with
9 due consideration of the benefits to South Carolina customers, issued two
10 orders approving pre-construction cost recovery as established in its June 9,
11 2008 *Order Approving Application of Duke Energy Carolinas' Decision to*
12 *Incur Nuclear Generation Pre-Construction Costs* and its July 1, 2011 *Order*
13 *Approving Amended Project Development Application and Settlement*
14 *Agreement*. DE Carolinas was issued a COL for the construction and operation
15 of the Lee Nuclear Project on December 19, 2016.

16 **Q. WAS DE CAROLINAS' DECISION TO START THE COLA EARLY**
17 **REASONABLE?**

18 A. Yes. It was well known to DE Carolinas that Part 52, although the best
19 licensing pathway available, was untested. Furthermore, long lead times have
20 been often associated with nuclear plant licensing. Many other utilities were
21 going to pursue COLs, and the number of COLAs under review was expected
22 to grow quickly. These uncertainties could hamper the development of a
23 nuclear project. Therefore, it was important to begin the licensing process

1 early enough to accommodate potential delays in order to exercise the license
2 when it was most beneficial to DE Carolinas customers.

3 **V. OBSTACLES TO LICENSING THE LEE NUCLEAR PROJECT**

4 **ON SCHEDULE**

5 **Q. WHAT WAS THE EXPECTED TIMEFRAME FOR AN APPLICANT**
6 **TO RECEIVE A COL WHEN DE CAROLINAS FILED ITS COLA?**

7 A. The NRC schedule called for an estimated forty-two months from docketing
8 to license, consistent with their schedule for the Design Certification.
9 However, it was expected in 2007 that forty-eight months was more probable
10 due to the large number of applications being docketed.

11 **Q. WHAT HAS BEEN THE ACTUAL EXPERIENCE OF UTILITIES**
12 **THAT HAVE OBTAINED A COL?**

13 A. The eight utilities pursuing fourteen COLs were divided into two groups for
14 the COLA reviews: Georgia Power (Vogtle plant) and SCE&G (Summer
15 plant) as lead plants and all the other applicants in a subsequent group.
16 Georgia Power and SCE&G had expressed their commitment to commence
17 construction right after issuance of the COL and were given preferential
18 review, as decided by the NRC Commissioners. The licenses for Summer and
19 Vogtle were issued in four years, essentially as scheduled. The other ten COLs
20 issued averaged 8.6 years from docketing to licensing. The Lee Nuclear
21 Project license was issued in nine years, slightly above the average. It appears
22 that all these utilities endured licensing delays from similar causes.

1 Q. WHAT WERE THE SPECIFIC ISSUES THAT IMPACTED THE
2 TIMING FOR THE ISSUANCE OF THE LEE NUCLEAR PROJECT
3 COL?

4 A. Two types of issues impacted timing of the issuance of the Lee Nuclear
5 Project COL: Issues directly related to NRC management of the licensing
6 review and issues related to DE Carolinas' improvements to the COLA from
7 voluntary and quasi-voluntary actions.

8 The individual impact of the issues discussed is difficult to quantify;
9 however, it is indisputable that each one of them and the aggregate resulted in
10 the licensing process taking significantly longer than originally anticipated for
11 the Lee Nuclear Project and other projects. The delay attributed directly to
12 issues dependent on the NRC management of the licensing review and issues
13 related to DE Carolinas improvements to the COLA are discussed below. It is
14 also important to note that the NRC must devote its attention to arising safety
15 issues for the operating nuclear plants, nuclear facilities, facilities under
16 construction, and other licensees prior to resolving new licensing issues. NRC
17 staff attention from 2010 to 2014 was frequently diverted from new reactor
18 licensing to other pressing safety-related matters. For example, the attention
19 that had to be devoted to the construction of the four AP1000 units at the
20 Vogtle and Summer sites, as ordered by the NRC Commission, reduced the
21 number of reviewers available for the Lee Nuclear Project licensing and
22 resulted in delays for DE Carolinas and the other applicants.

1 **A. Delays Related to the Yucca Mountain Licensing Review**

2 **Q. PLEASE EXPLAIN THE IMPACT OF THE YUCCA MOUNTAIN**
3 **LICENSING REVIEW.**

4 **A.** The Yucca Mountain licensing review took critical NRC staff away from
5 reactor licensing issues in the areas of seismic, geology, site characterization,
6 and environmental reviews. Since 2010, the review of the Yucca Mountain
7 licensing application has been stopped and then restarted, with complex legal
8 and budgeting issues complicating progress. Instabilities in the NRC's staffing
9 assignments occurred. Specifically, environmental, geologic and seismic
10 experts were diverted to these efforts, which lasted about four years. On
11 October 16, 2014, the NRC issued the very important Volume 3 of the Yucca
12 Mountain Safety Evaluation Report ("SER"), concluding that the design met
13 applicable performance objectives for safety following permanent closure of
14 the repository. On December 18, 2014, the staff issued Volume 4
15 (Administrative and Programmatic Requirements) of the SER, and on January
16 29, 2015, the staff issued the final parts of the review, Volume 2 (Repository
17 Safety Before Permit Closure) and Volume 5 (Proposed Conditions and
18 License Specifications), which completed the SER. Completion of these
19 reports allowed for the resumption of more standard review schedules after
20 2014. The Staff resource instability while the Yucca Mountain SER was being
21 prepared contributed to the delay in reactor licensing reviews.

B. Delays Related to the Waste Confidence Rule

Q. PLEASE PROVIDE MORE DETAILS ABOUT THE NRC'S WASTE CONFIDENCE RULE.

A. Between 1979 and 2010, the NRC established that spent nuclear fuel would be safely stored in a manner protecting public health and safety, the environment, and the common defense and security after the reactor's licensed life through a periodic generic determination of the issue, commonly known as the Waste Confidence Rule. The Waste Confidence Rule relied on confidence that the U.S. government will eventually establish a suitable repository for spent fuel. On December 23, 2010, the NRC published its most recently revised Waste Confidence Rule. This rule reaffirmed and amended the NRC's generic determinations regarding the environmental impacts of spent nuclear fuel storage at or away from reactor sites after the expiration of reactor operating licenses. In June 2012, the U.S. Court of Appeals for the D.C. Circuit vacated and remanded the NRC's Waste Confidence Rule. The Court held that the NRC must perform additional environmental reviews associated with the rule. The NRC suspended the issuance of new reactor licenses and license extensions that were reliant on this generic determination; however, the NRC continued the review of pending applications. Finally, the NRC issued the final Continued Storage of Spent Nuclear Fuel rule on August 26, 2014, significantly changing the considerations about the safety of continued storage of spent nuclear fuel to be independent of a national spent fuel repository. The ruling, made effective after publication in the Federal Register on September

1 19, 2014, effectively resolved the issues on the storage of spent fuel and ended
2 the power reactor licensing suspension. The new Continued Storage of Spent
3 Nuclear Fuel Rule adopts the findings from the new NRC generic
4 environmental impact statement; it establishes that spent nuclear fuel can be
5 safely managed in dry casks for the short-term (up to 60 years), the long-term
6 (another 100 years), and for indefinite time frames. The new rule does not
7 rely on the availability of a repository for the safe storage of spent fuel. The
8 two-year suspension of licensing provided another uncertainty and delay at a
9 time when the DE Carolinas COL review was advancing.

10 **C. Delays Related to the Fukushima Dai-ichi Accident**

11 **Q. PLEASE PROVIDE MORE DETAIL ABOUT THE FUKUSHIMA DAI-**
12 **ICHI ACCIDENT.**

13 **A.** On March 11, 2011, the Great East Japan Earthquake and subsequent tsunami
14 caused major loss of life and destruction of property in Japan. In addition, the
15 tsunami led to a series of flooding events that disrupted the electrical power
16 and equipment necessary to cool the reactors in three of the units in the
17 Fukushima Dai-ichi nuclear power plant. The lack of cooling capability, not
18 restored in time, resulted in the core meltdown and radioactivity releases from
19 units 1, 2, and 3 of the Fukushima plant. The global nuclear sector responded
20 immediately to this event with a reexamination of nuclear power plants
21 protection from large external events, especially from flooding.

1 **Q. WHAT WAS THE NRC’S RESPONSE TO THE FUKUSHIMA DAI-**
2 **ICHI ACCIDENT?**

3 A. The U.S. NRC responded immediately by assembling the Near-Term Task
4 Force (NTTF) to complete a Review of Insights from the Fukushima Dai-Ichi
5 Accident. The Task Force issued an insightful and far-reaching 2011 report on
6 “Recommendations for Enhancing Reactor Safety in the 21st Century”, which
7 mostly addressed issues pertinent to operating nuclear power plants. The
8 NRC, from the beginning of this new analysis of extreme external events,
9 concluded that the AP1000 passive-safety reactor selected for the Lee Nuclear
10 Project has significant and inherent safety enhancements that address many of
11 the Fukushima-related safety issues. AP1000 reactors only required review
12 and potential improvements in a few well-defined safety areas. The NRC has
13 stated that “all of the current COL and design certification applicants are
14 addressing new seismic and flooding requirements adequately in the context
15 of updated NRC guidance.”

16 **Q. WHAT WAS THE IMPACT OF THE FUKUSHIMA DAI-ICHI**
17 **ACCIDENT ON THE LEE NUCLEAR PROJECT?**

18 A. The NRC’s extensive regulatory review and requirements after the Fukushima
19 Dai-ichi accident disrupted the NRC license review sequencing and added a
20 few important issues to be considered in DE Carolinas’ COLA. As necessary
21 and required for a safety agency, the NRC was ensuring that all issues
22 potentially related to the Fukushima accident and external events in general
23 were thoroughly reviewed, and operating plants were clearly the priority.

1 Delays in new reactor licensing were inevitable. The actions specifically
2 required by the NRC for the Lee Nuclear Project, in accordance with the
3 Fukushima Near-Term Task Force recommendations, were dealt with during
4 the COLA review and incorporated into the license conditions, including: 1)
5 specific actions associated with the agency's post-Fukushima requirements for
6 mitigation strategies and spent fuel instrumentation; and 2) a pre-startup
7 schedule for post-Fukushima aspects of the new reactors' emergency
8 preparedness and procedures. These additions and the review of the operating
9 fleet also contributed to the delay of the issuance of the Lee COL.

10 **D. The Delay Related to Seismic Source Characterization**

11 **Q. PLEASE EXPLAIN THE NEW SEISMIC SOURCE**
12 **CHARACTERIZATION.**

13 **A.** By 2009, the NRC was actively reviewing the seismic models for the Central
14 and Eastern United States ("CEUS") Seismic Source Characterization for
15 Nuclear Facilities based on the known facts that ground motion effects could
16 be better characterized than in earlier NRC rules. After determining the best
17 methods to use, probabilistic assessments were incorporated into the models.
18 The NRC defined the CEUS project as follows: "The objective of the CEUS
19 SSC Project is to develop a new seismic source model for the CEUS using a
20 Senior Seismic Hazard Analysis Committee (SSHAC) Level 3 assessment
21 process. The goal of the SSHAC process is to represent the center, body, and
22 range of technically defensible interpretations of the available data, models,

1 and methods. Input to a probabilistic seismic hazard analysis (PSHA) consists
2 of both seismic source characterization and ground motion characterization.”

3 **Q. WHAT IMPACT DID THE NEW SEISMIC SOURCE**
4 **CHARACTERIZATION HAVE ON THE LICENSING OF THE LEE**
5 **NUCLEAR PROJECT?**

6 A. The new NUREG-2115 “Central and Eastern United States Seismic Source
7 Characterization for Nuclear Facilities” was published in January 2012 and
8 was incorporated into the DE Carolinas’ license application for the Lee
9 Nuclear Project. It was another new issue to address in DE Carolinas’ COLA,
10 and licensing delays were incurred.

11 **Q. WHAT COMMON IMPACT DID THE YUCCA MOUNTAIN**
12 **LICENSING REVIEW, THE REMANDED WASTE CONFIDENCE**
13 **RULE, THE FUKUSHIMA DAI-ICHI ACCIDENT, AND THE CEUS**
14 **SEISMIC SOURCE HAVE ON THE LEE NUCLEAR PROJECT?**

15 A. Besides the above-described individual impacts from each one of these
16 occurrences, there is a significant cumulative and not well-quantified effect on
17 all the pending new reactor licenses. The NRC staffing and contractors work
18 was more affected in a common area: environmental, siting, geologic and
19 seismic reviews. Substitutions of experienced NRC staff or contractors
20 assigned to a project were not conducive to efficient reviews when
21 considering the sequencing and coordination of the licensing review steps
22 necessary to arrive at Final Safety Evaluation Reviews (FSERs), Final
23 Environmental Impact Statements, Final Safety Analysis Reports (FSARs),

1 Advisory Committee on Reactor Safeguards (ACRS) reviews with No Open
2 Items, and, finally, to the conduct of hearings and NRC Commission
3 Approval.

4 **E. Delays Related to Changes in Design Certification and Reference Plant**

5 **Q. PLEASE EXPLAIN THE IMPACT OF THE AP1000 DESIGN**
6 **CERTIFICATION AMENDMENT ON DE CAROLINAS' COLA**
7 **REVIEW.**

8 A. When DE Carolinas' COLA was docketed in 2008, it referenced the latest
9 DCD for the AP1000 Design Certification, Revision 16 ("Rev 16"). In
10 December 2011, about four years after DE Carolinas' COLA submittal,
11 Westinghouse obtained approval for the "final" upgrade of its design
12 certification, docketed as Revision 19 ("Rev 19") to the DCD. It was
13 suggested by the NRC that utilities referencing Rev 16 could benefit by
14 changing its COLA to reference Rev 19 of the AP1000 DCD; the Design-
15 Centered Review Approach group would be able to maintain a common DCD
16 for their applications review. DE Carolinas changed its COLA to reference
17 Rev 19 of the AP1000 by submitting Revision 4 of the COLA on 7/29/2011. It
18 should be remarked that the COLA must also describe the Inspections, Tests,
19 Analyses, and Acceptance Criteria ("ITAAC") that are necessary to ensure
20 that the plant has been properly constructed and will operate safely. When the
21 application references a standard design certification, the applicant must
22 perform the ITAAC for the certified design and the site-specific design
23 features. Any changes must be reflected in the ITAACs. The change to DCD

1 Rev 19 required modification of DE Carolinas' COLA, including ITAACs,
2 necessitating subsequent adjustments, NRC questions, and NRC interactions.
3 The challenges with the design certification amendment and the external
4 factors discussed above occurred generally between 2010 and 2015, which
5 was the most critical period for advancing the NRC's review of the Lee COL
6 application, and directly resulted in the delay of the NRC's issuance of the
7 Lee COL.

8 **F. DE Carolinas' Improvements to the COLA**

9 **Q. PLEASE PROVIDE SOME ADDITIONAL DETAIL ABOUT DE**
10 **CAROLINAS' DECISION TO CHANGE THE LOCATION OF THE**
11 **REACTOR.**

12 A. DE Carolinas determined that the Lee nuclear reactor would be better
13 anchored at a different location than the one initially selected for the COLA.
14 My review of the Company's decision to change the location of the reactor
15 indicates that this decision was a cost-effective change that would result in
16 improved reactor building stability and more economic construction.
17 However, a change to the COLA was necessary. Any COLA change requires
18 preparation, review, and additional time.

19 **Q. WHAT WERE THE BENEFITS OF THIS DECISION?**

20 A. The benefits of this decision are first found in the NRC staff review of the Part
21 100 - Reactor Site Criteria, minimizing challenges by the staff and promoting
22 efficiencies in the review. Also, it is significantly beneficial for the
23 determination of the reactor site excavation, concrete foundation, and

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1 placement of other buildings. It would pay off in the cost of the plant
2 construction.

3 **Q. WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO DE**
4 **CAROLINAS' DECISION?**

5 A. It was reasonable and prudent for the reasons discussed above.

6 **Q. PLEASE EXPLAIN DE CAROLINAS' DECISION WITH RESPECT**
7 **TO ADDING A MAKE-UP POND.**

8 A. DE Carolinas' decision to add a make-up pond for cooling water to the Lee
9 Nuclear Project was based on the limited amount of water in the Ninety-Nine
10 Islands Reservoir, the main cooling water source for the plant. The limitation
11 was made evident during the drought of 2007-2008. The make-up pond, not a
12 safety-related system, was deemed appropriate to maintain the plant's rated
13 power and avoid interfering with the operations of dams and the water
14 supplies of adjacent communities.

15 **Q. WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO DE**
16 **CAROLINAS' DECISION?**

17 A. It was a reasonable and prudent decision considering the circumstances
18 established by the above-discussed issues emphasizing availability of water
19 for plant cooling, dams, and town consumption during droughts.

20 **Q. PLEASE PROVIDE SOME ADDITIONAL DETAIL ABOUT DE**
21 **CAROLINAS' DECISION TO CHANGE THE COOLING TOWERS.**

22 A. In December 2011, DE Carolinas decided to submit an amendment to the
23 COLA revising the cooling tower design for the Lee Nuclear Project. After an

1 optimization study and alignment of the design to the Summer units' cooling
2 towers, DE Carolinas changed the cooling water supply to the Component
3 Cooling Water System ("CCWS") design from three to two cooling towers per
4 unit to improve the basins, site flooding resistance, as well as to improve the
5 overall reliability of the CCWS. These changes were responsive to an NRC
6 Request for Additional Information ("RAI").

7 **Q. WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO DE**
8 **CAROLINAS' DECISION TO CHANGE THE COOLING TOWERS?**

9 A. It was a reasonable and prudent decision to improve the project design, the
10 site characterization, as well as to provide appropriate response to the NRC in
11 the post-Fukushima flooding concerns arena.

12 **G. Overcoming the Challenges of Part 52**

13 **Q. WHAT EFFECT DID THE USE OF PART 52 HAVE ON THE LEE**
14 **NUCLEAR PROJECT?**

15 A. The use of Part 52 licensing has proven to be difficult for DE Carolinas and
16 the other applicants seeking a COL referencing a Design Certification. It has
17 also proven difficult at the construction stage, as evidenced by the projects at
18 Vogtle and Summer. Moving from Part 50 to Part 52 introduced many new
19 processes and strict control for departures from the Design Certification.
20 Conformance with the DCD of the certified design and the COL finality
21 requires meeting codes and standards prior to issuance, among other rigid
22 processes. Changes have been controlled by conservative NRC Staff
23 interpretations on some DCD documents that were not well defined.

1 Specifically, all design-related information in the so-called Tier 1 of the DCD
2 is well-controlled since it is established by rulemaking and can only be
3 changed by rulemaking. However, the design-related information contained in
4 Tier 2 of the DCD, which supports the Tier 1 information, is approved but not
5 certified by rulemaking. Changes to and departures from Tier 2 are strictly
6 governed by Appendix D to Part 52, Section VIII. Furthermore, a part of Tier
7 2, designated as Tier 2*, is treated separately and was supposed to provide
8 flexibility to applicants to make changes by using license amendments. In this
9 way, changes to important design methodologies and improvements in
10 technology could be accommodated but would be subject to review. At the
11 beginning, three or four such areas of improvements were believed to be in the
12 scope of Tier 2* design-related information. Eventually, twenty-four such
13 areas were designated AP1000 Tier 2*. Change processes have been therefore
14 cumbersome and time consuming, adding to the licensing delays. I believe
15 that the licensing process established by Part 52 is the best option for licensing
16 a nuclear power plant, but it needs improvements for better implementation
17 while maintaining the public health and safety, protecting the environment,
18 and the common defense and security. Moreover, implementation of Part 52
19 has been difficult for the lead plants, especially with regard to the completion
20 of the detailed design. This issue is one of the most important to resolve for
21 new nuclear plants in the US and abroad.

1 **Q. PLEASE PROVIDE AN EXPLANATION OF DE CAROLINAS'**
2 **MANAGEMENT OF RAIS AND GENERIC DESIGN CERTIFICATION**
3 **ISSUES.**

4 A. It is common to encounter a significant amount of additional and often
5 unexpected work when responding to RAIs from the NRC. For the Lee
6 Nuclear Project COLA review, this process was more arduous because the
7 implementation of Part 52 was still developing and other issues, such as the
8 Waste Confidence Rule and the Fukushima Daiichi accident, required the
9 attention of the NRC Commission and Staff. Also, there were errors and
10 changes to the AP1000 DCD and ongoing refinement or changes to seismic
11 and geologic, instrumentation and control, control room, and emergency
12 planning, as well as other emerging issues. AP1000 generic issues were being
13 resolved after the Design Certification, and these standardization and finality
14 reviews and changes took additional time. The changeover from Rev 16 to
15 Rev 19 was not complicated, but it also took additional time, as did the
16 seismic re-analysis resulting from NUREG-2115.

17 **Q. PLEASE CITE ANOTHER SPECIFIC ISSUE WITH THE AP1000 DCD**
18 **THAT IMPACTED THE DE CAROLINAS COL ISSUANCE.**

19 A. Late in its review of DE Carolinas' COLA, in September 2014, the NRC
20 notified the Lee Nuclear Project reference plant (Levy Nuclear Plant) of
21 design errors in Westinghouse's DCD Rev 19. These errors tripped the
22 thresholds established in Interim Staff Guidance ("ISG-11"), which clarifies
23 the NRC staff's position regarding the finalization of licensing basis

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1 information for COL applicants. The above-referenced issues included
2 handling of combustible gas controls, main control room ("MCR") heat-up,
3 habitability, dose responses and condensate return. This ISG-11 issue involved
4 all COL applicants in the Design Review Group, and it took a year to receive
5 clarification from the NRC to address how COL applicants could best resolve
6 generic errors in certified designs. The complexity of the issues and the
7 constraints from "design finality" required a major effort by Lee Nuclear
8 Project licensing management to address and eventually endorse the reference
9 plant's gas control, habitability, flux doubling, MCR dose, and condensate
10 return responses to the NRC. The effort was completed in February 2016,
11 some seventeen months after the issue was identified.

12 **Q. HOW EXTENSIVE AN EFFORT WAS REQUIRED FOR DE**
13 **CAROLINAS TO RESPOND TO RAIS REGARDING THE LEE**
14 **NUCLEAR PROJECT?**

15 A. As discussed above, the effort was extensive, continuous, and time-
16 consuming.

17 **Q. WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO DE**
18 **CAROLINAS' MANAGEMENT OF THESE ISSUES?**

19 A. DE Carolinas' management of these issues was reasonable and prudent. DE
20 Carolinas' approach was consistent with effective practices to respond to NRC
21 inquiries as needed for the NRC to complete its review.

1 **Q. WERE THERE OTHER ISSUES THAT MAY HAVE CONTRIBUTED**
2 **TO THE TIME REQUIRED TO OBTAIN A COL FOR THE LEE**
3 **NUCLEAR PROJECT?**

4 **A.** I am certain that the issues discussed above are a representative sample of the
5 many challenges encountered by DE Carolinas in the resolution of issues
6 required to obtain a COL from the NRC. Other issues, whose impact are not
7 well characterized, occurred during the NRC review process in the period
8 under consideration, to include turnover at the Commission level and senior
9 NRC staff. Also, other agencies have corresponding or specific
10 responsibilities with respect to plans for nuclear plant construction. For
11 instance, the U.S. Army Corps of Engineers (USACE), the U.S.
12 Environmental Protection Agency (EPA), the U.S. Forest Service, the South
13 Carolina Department of Health and Environmental Control, and other local
14 agencies had their own set of permit issues. In summary, it would be
15 demanding to license a power reactor under normal circumstances. The period
16 2008-2016 was not normal, as explained in detail above. Consequently, the
17 issuance of the Lee Nuclear Project COL was delayed well beyond original
18 expectations.

19 **Q. COULD THE WASTE CONFIDENCE RULE, FUKUSHIMA, CEUS,**
20 **WESTINGHOUSE DESIGN CHANGES, AND PART 52 ISSUES HAVE**
21 **BEEN PREDICTED BEFOREHAND TO DELAY THE RECEIPT OF**
22 **THE LICENSE BY FOUR TO FIVE YEARS?**

23 **A.** No.

1 **VI. REVIEW OF DE CAROLINAS COL AND PROJECT-RELATED**
2 **DECISIONS AND COSTS**

3 **Q. HAVE YOU REVIEWED THE COST BREAKDOWN FOR THE COL**
4 **AND PROJECT-RELATED COSTS THAT DE CAROLINAS IS**
5 **SEEKING APPROVAL TO RECOVER?**

6 A. Yes. I have reviewed summary information provided by DE Carolinas for
7 different time periods of the project, including filings for cost recovery with
8 the North Carolina Utilities Commission and the PSCSC. It is my
9 understanding that DE Carolinas is seeking to recover approximately \$518
10 million for the entire licensing project, which includes \$270 million for
11 project expenses and \$248 million for AFUDC. FP&L has reported
12 expenditures to the FPSC of \$267 million for the site selection and pre-
13 construction (exclusive of financing charges) as of December 31, 2017. The
14 \$270 million for site and pre-construction costs, including COL maintenance
15 costs, incurred by DE Carolinas in this case compares well to the amount of
16 cost incurred by FP&L for similar work conducted for Turkey Point Units 6
17 and 7.

18 **Q. WHAT WOULD HAVE BEEN THE DISADVANTAGES OF**
19 **SUSPENDING EFFORTS TO LICENSE THE LEE NUCLEAR**
20 **PROJECT AND RESTARTING THIS EFFORT AT A SUBSEQUENT**
21 **TIME?**

22 A. The disadvantages include the difficulty and cost related to suspending the
23 COLA, the effort and cost of re-starting it when potentially facing changes to
24 the overall regulatory framework, and losing a dedicated expert management

1 and staff group at the NRC cognizant of the Lee Nuclear Project. Moreover,
2 the main disadvantage would be not having a readily-executable license to
3 construct and operate the Lee Nuclear Project at the time most favorable for
4 DE Carolinas customers.

5 **Q. WHAT IS THE VALUE TO DE CAROLINAS OF HAVING A COL FOR**
6 **THE LEE NUCLEAR PROJECT?**

7 A. The value of DE Carolinas' COL includes its intrinsic importance in the
8 capability of deploying a nuclear power plant when most beneficial for a
9 licensed life of forty years, with the possibility of additional license renewals.
10 The COL is a readily available asset for DE Carolinas. It includes a very
11 valuable, environmentally-screened tract of land and cooling water, quite
12 suitable for large power generation.

13 **Q. PLEASE PROVIDE SOME ADDITIONAL DETAILS ABOUT WHY**
14 **THE LEE NUCLEAR PROJECT REMAINS VALUABLE.**

15 A. The value of the Lee Nuclear Project derives primarily from two substantive
16 assets: the Lee COL issued by the NRC and the availability of an
17 environmentally suitable site, with the requirements for large power
18 generation, already studied and approved.

19 **Q. WHY DOES THE LEE COL REMAIN A VALUABLE ASSET?**

20 A. The Lee COL enables DE Carolinas to build two AP1000 units on the Lee
21 Nuclear Project site if DE Carolinas chooses to do so. As I explain in more
22 detail above, the value of a COL for the construction and operation of an
23 advanced passive safety nuclear power reactor lies in its durability, finality,

1 and capability to be executed when the licensee determines it is in the best
2 interest of its customers.

3 **Q. PLEASE PROVIDE SOME ADDITIONAL DETAIL ABOUT HOW**
4 **PART 52 LIMITS REGULATORY CHANGES TO THE LEE COL.**

5 A. The finality of the COL is strictly established by 10 C.F.R. § 52.98, especially
6 at § 52.98 (a): "After issuance of a combined license, the Commission may
7 not modify, add, or delete any term or condition of the combined license, the
8 design of the facility, the inspections, tests, analyses, and acceptance criteria
9 contained in the license which are not derived from a referenced standard
10 design certification or manufacturing license, except in accordance with the
11 provisions of § 52.103 or § 50.109 of this chapter, as applicable." Moreover,
12 the issues that are resolved in a standard design certification ruling are also
13 subjected to a very strict change process, and the NRC can only modify a
14 certified design under very limited circumstances, such as if the NRC finds
15 that the design does not meet the applicable regulations in effect at the time of
16 the Design Certification, or if it is necessary to modify the design to assure
17 adequate protection of the public health and safety, as established in 10 C.F.R.
18 § 52.63. Even if the Design Certification changes or expires, DE Carolinas
19 can select to construct and operate the Lee Nuclear Project as licensed as of
20 December 19, 2016, including specified license conditions and accepted
21 recommendations. The capability to construct and operate as licensed is a key
22 feature and advantage of the finality rules of 10 C.F.R. Part 52. In this regard,
23 it is notable that the Tennessee Valley Authority ("TVA") received a 1973

1 construction permit under 10 C.F.R. Part 50 for Watts Bar Unit 2, stopped
2 construction in 1985, and reinitiated construction in 2007 under an extended
3 construction permit. The NRC issued TVA a 10 C.F.R. Part 50 operating
4 license for Watts Bar Unit 2 in 2015, and Watts Bar Unit 2 is currently in
5 service. The Lee COL, which was issued pursuant to 10 C.F.R. Part 52,
6 provides greater certainty with respect to the finality and capabilities of the
7 license than was afforded to TVA under its 10 C.F.R. Part 50 construction
8 permit.

9 **Q. WHAT ARE THE BENEFITS OF HAVING THE LEE NUCLEAR**
10 **PROJECT AS AN ENVIRONMENTALLY-SCREENED SITE?**

11 A. The value of the Lee Nuclear Project as an environmentally-screened site is
12 that the site has been rigorously examined and determined to be suitable to
13 sustain a nuclear power plant. This determination includes the site's geology /
14 hydrology / seismology / meteorology characteristics, population density and
15 nearby man-made infrastructures, access roads and land improvements, and
16 the valuable cooling water in compliance with national and regional use
17 requirements. These determinations are supported by the record of decisions
18 compiled over a decade of work.

19 **Q. HOW DO THESE FACTORS MAKE THE LEE NUCLEAR PROJECT**
20 **VALUABLE?**

21 A. Having completed the significant technical effort that was required to
22 characterize the site and obtain many of the regulatory approvals that are
23 required to build and operate a nuclear power plant on the site, DE Carolinas

1 now has the option to execute the Lee Nuclear Project if and when the time is
2 right. This factor makes the Lee Nuclear Project an asset of considerable
3 value to DE Carolinas' customers.

4 **Q. WHAT ARE THE ADVANTAGES OF THE LICENSING-FIRST**
5 **APPROACH TAKEN BY DE CAROLINAS?**

6 A. The advantages of the licensing-first approach taken by DE Carolinas rest on
7 the capability for DE Carolinas' management to review the costs and risks of
8 the Lee Nuclear Project as the design develops to ensure the viability of
9 initiating nuclear construction, while proceeding at a pace where DE
10 Carolinas could benefit from the lessons learned of other utilities also
11 pursuing new nuclear generation. More importantly, DE Carolinas customers
12 will have the advantage of having a license that will reduce significantly the
13 lead time necessary to build and construct a future nuclear unit if there is a
14 decision to go forward with the construction of a nuclear facility in the future.

15 **Q. WAS THE SELECTION OF THE AP1000 DESIGN REASONABLE,**
16 **WHEN CONSIDERING THE PROBLEMS ULTIMATELY**
17 **ENCOUNTERED WITH THE LICENSING AND THE**
18 **CONSTRUCTION OF AP1000 REACTORS?**

19 A. Yes. The AP1000 design was and I believe continues to be the best reactor
20 technology available, with the most advanced safety features and potential for
21 economic deployment. Most of the proximate causes of rising cost and
22 construction delays associated with new nuclear builds in the United States
23 are attributable to the thirty-year hiatus in U.S. nuclear construction, not the

1 novelty of the AP1000 design. The significant problems with the Vogtle and
2 Summer units are construction problems, beginning with the lack of extensive
3 detailed design prior to and after construction startup, the introduction of
4 modular construction, the construction management organization, the
5 scheduling, the labor force, the supply chain, and changes thereto. These
6 issues would be addressed prior to a decision to construct and operate by any
7 of the utilities holding COLs that have not yet undertaken construction. DE
8 Carolinas customers have been protected from potential cost overruns and
9 delays from moving first in a restarted industry like new nuclear construction.
10 However, by having a COL, DE Carolinas is still in a position to pursue new
11 nuclear if and when it becomes appropriate to do so for its customers.

12 **Q. WHAT IS THE NEAR-TERM IMPACT OF THE WESTINGHOUSE**
13 **BANKRUPTCY, DISCONTINUATION OF CONSTRUCTION WORK,**
14 **AND THE FINANCIAL ISSUES WITH THE SOUTH CAROLINA AND**
15 **GEORGIA POWER PLANTS?**

16 A. The impact of the above issues during most of 2017 were disruptive for the
17 South Carolina and Georgia plants' construction, as well as increasing
18 uncertainty and risk for other near-term nuclear plant construction. With
19 Westinghouse's bankruptcy and its exiting the construction business, it
20 became critical to re-evaluate project execution strategies for new nuclear and
21 how engineering, procurement and construction would be undertaken to
22 adhere to a reliable cost and schedule.

1 The construction of the South Carolina (SCE&G and Santee Cooper)
2 nuclear power plant stopped shortly after the Westinghouse announcements.
3 In July 2017, SCE&G and Santee Cooper announced that they would abandon
4 the V.C. Summer Units 2 and 3 project. In December 2017, SCE&G applied to
5 the NRC to suspend the COL licenses for VC Summer Units 2 & 3.

6 On the other hand, with many difficulties, the construction of the
7 Vogtle Nuclear Power Plant ("NPP") is continuing with support from the
8 federal government and approval in December 2017 by the Georgia Public
9 Service Commission. The Vogtle NPP will receive federal production tax
10 credits after it achieves commercial operation. Furthermore, a conditional
11 commitment for additional loan guarantees from the Department of Energy
12 would add \$3.7 Billion to the companies supporting the construction: \$1.67
13 Billion for Georgia Power, \$1.6 Billion for Oglethorpe Power Corp., and \$415
14 Million for the Municipal Electric Authority of Georgia for the construction of
15 the two reactors. Construction has continued at Vogtle, with over 6,000
16 workers presently at the plant, with completion expected for Vogtle Units 3
17 and 4 by 2021 and 2022 respectively.

18 In the international arena, Westinghouse's AP1000 nuclear reactors in
19 China are achieving significant milestones. Sanmen Unit 1 was connected to
20 the electrical grid on June 30, 2018, and entered commercial operation on
21 September 21, 2018. In addition, Sanmen Unit 2 was connected to the grid in
22 August and is expected to enter commercial operation before the end of 2018.
23 The other two AP1000 units in Haijiang are also achieving operational

1 milestones, with Haijang 1 already connected to the grid and expected to be in
2 commercial operation by December 2018. Haijang 2 is expected to be in
3 commercial operation before mid-year 2019.

4 It is important to note that the acquisition of Westinghouse by
5 Brookfield Business Partners LP's has been finalized and Westinghouse has
6 exited bankruptcy. These developments are very important news for existing
7 Westinghouse customers and their nuclear businesses, as Westinghouse is still
8 the largest provider of nuclear services in the world.

9 Furthermore, the U.S. Department of Energy is strongly supporting the
10 sale of six nuclear units by Westinghouse to India, and federal efforts continue
11 to support the important role of nuclear power for the USA security, stability,
12 contribution to amelioration of carbon releases, and long-time economics.

13 **Q. WHAT MUST DE CAROLINAS DO TO MAINTAIN THE COL**
14 **FOLLOWING ITS ISSUANCE?**

15 A. DE Carolinas must conduct those activities necessary to ensure the issued
16 COL continues to be protective of the safety and health of the public, the
17 environment, and the common defense and security in a manner consistent
18 with NRC regulations. The COL is valid for forty years from the date the
19 Commission finds the acceptance criteria were met under 10 CFR §
20 52.103(g). Presently, the COL can be renewed for an additional twenty years,
21 following a well-established process. The maintenance efforts and costs are
22 minimal until the decision to proceed with the construction is made.
23 Additional revisions and costs could be incurred if the NRC determines that a

1 safety issue needs to be reviewed and incorporated into the license, but these
2 costs would not expected to be significant since they would likely be covered
3 under a Design Certification Amendment.

4 **VII. CONCLUSIONS**

5 **Q. BASED ON YOUR REVIEW OF THE LEE COLA PROCESS,**
6 **INCLUDING DELAYS, AND WITH CONSIDERATION OF ALL**
7 **IMPORTANT FACTORS AFFECTING THE REVIEW SCHEDULE,**
8 **WERE THE DE CAROLINAS DECISIONS AND ACTIONS**
9 **REASONABLE?**

10 **A.** Yes. Based on my experience, a review of DE Carolinas' decisions and actions
11 leads me to conclude that the stepwise approach to licensing and managing the
12 project for the Lee Nuclear Project, and its decision to extend their target
13 operation dates, are reasonable and consistent with industry best practices.
14 Decisions were made to conduct necessary activities and to defer others, in
15 accordance with the primary decision to obtain a license. For example, DE
16 Carolinas made conscious decisions to defer certain long-lead procurement
17 decisions and did not enter into an Engineering, Procurement, and
18 Construction contract for the project. By choosing to reserve these
19 expenditures until a later time, DE Carolinas showed sound risk management
20 and will be able to make these decisions with the appropriate information in
21 the future. It has preserved the option for future nuclear generation for its
22 customers, with a license that can be exercised when the energy and economic
23 conditions are favorable for base-loaded nuclear electricity generation.

1 **Q. PLEASE PROVIDE YOUR OVERALL CONCLUSION OF THE**
2 **PROJECT COSTS INCURRED FOR THE LEE NUCLEAR PROJECT.**

3 **A. I find that the project costs incurred for the Lee Nuclear Project are reasonable**
4 and prudent. The elevated AFUDC costs are due to the protracted proceedings
5 to obtain the COL license; the multiple causes for the delay are well justified
6 in the preceding discussions. I believe that DE Carolinas took technically and
7 financially sound steps to enable the licensing and project activities for the
8 Lee Nuclear Project.

9 **Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

10 **A. Yes.**

1 MR. MARZO: Mr. Chairman, the witnesses are
2 available for cross-examination.

3 CHAIRMAN RANDALL: Before we get to cross, I
4 just want you to know I did see all the looks of
5 apprehension from all of you when Mr. Dong left the
6 bench and left me driving by myself.

7 [Laughter]

8 But we'll begin cross after a short break.

9 [WHEREUPON, a recess was taken from 3:02
10 to 3:20 p.m.]

11 CHAIRMAN RANDALL: Please be seated. Okay.
12 We'll start with cross. Vote Solar?

13 MR. ELLERBE: They don't have any cross, Mr.
14 Chairman.

15 [Laughter]

16 MR. ELLIOTT: I think it's me, Mr. Chairman.
17 Anybody ahead of me?

18 CHAIRMAN RANDALL: Nobody from Vote Solar?
19 Okay. Want to make sure.

20 NAACP, Coastal Conservation League, Upstate
21 Forever? Okay.

22 Sierra Club? Okay.

23 Mr. Elliott –

24 MR. ELLIOTT: If I may.

25 CHAIRMAN RANDALL: – I'm afraid it's you.

1 MR. ELLIOTT: Yes, sir.

2 CHAIRMAN RANDALL: Well, I'm not afraid it's
3 you.

4 [Laughter]

5 MR. ELLIOTT: Thank you, Mr. Chairman.

6 CROSS EXAMINATION

7 BY MR. ELLIOTT:

8 Q Mr. Fallon.

9 A [FALLON] Yes?

10 Q If I may, let me ask you just a few questions, In your
11 testimony, I thought you did a very nice job of
12 outlining the history of Duke's efforts to obtain
13 authority to recover preconstruction costs for the Lee
14 nuclear facility. And if it would help you, you know,
15 I'll draw your attention to page 12. I don't know that
16 you'll need this. But you testified that on December 7,
17 2007, in Docket No. 2007-440-E, Duke – and I'll call it
18 “Duke” – filed an Application for Approval of the
19 Decision to Incur Nuclear Generation Preconstruction
20 Costs. Do you recall testifying to that?

21 A [FALLON] Yes.

22 Q All right. And you understand that that application was
23 filed pursuant to a South Carolina Code Section 58-33-
24 225. You recall that?

25 A [FALLON] Yes.

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1 Q And do you recall, just generally speaking, Mr. Fallon,
2 that that code section was enacted as a part of the Base
3 Load Review Act of 2007? Do you recall that?

4 A [FALLON] Yes.

5 Q So you filed under the Base Load Review Act for recovery
6 of preconstruction costs, correct?

7 A [FALLON] Yes.

8 Q Now, you seem to be – in your testimony, you testify
9 about the order in both the 2007 and the 2009 dockets,
10 so I'd like to show you, if I may –

11 A [FALLON] Is that the 2009 or 2011?

12 Q Excuse me, 2011. Beg your pardon. I'd like to show you
13 Order No. 2008-417 in a matter captioned Application of
14 Duke Energy Carolinas for the Approval of Decision to
15 Incur Nuclear Generation Preconstruction Costs.

16 MR. MARZO: Mr. Chairman, I would just ask if
17 counsel can provide me and also the witness an
18 order?

19 MR. ELLIOTT: Oh, I'm happy to. I think the
20 witness is looking at his. Would you like to see
21 mine?

22 MR. MARZO: Do you need yours to do your
23 presentation, or do you have an extra?

24 MR. ELLIOTT: No, I just have mine. I knew
25 Mr. Fallon would be prepared. I didn't – I thought

1 you might be familiar with it. Would you like to
2 see mine?

3 MR. MARZO: I am familiar with the order, but
4 I just want to be sure we're talking about the same
5 order.

6 MR. ELLIOTT: Yeah, but I mean, I'm --

7 MR. MARZO: Could you bring it to me so we
8 could make sure?

9 MR. ELLIOTT: Happy to [indicating].

10 MR. MARZO: [Indicating.]

11 MR. ELLIOTT: I'll say this loud enough for
12 everybody to hear: I'm going to ask Mr. Fallon
13 about the 2011 order also [indicating].

14 MR. MARZO: [Indicating.] Okay.

15 MR. ELLIOTT: Okay?

16 MR. MARZO: Yes.

17 MR. ELLIOTT: Thank you, counsel.

18 BY MR. ELLIOTT:

19 Q And I simply place this on the ELMO to ask you if this,
20 at least from the first page, appears to be the same
21 Order No. 2008-417 that you referred to in your
22 testimony?

23 A [FALLON] Yes.

24 Q And in that docket, Duke applied for about \$230 million
25 in costs to be approved by this Commission, for various

1 preconstruction items; is that correct?

2 **A** [FALLON] Yes.

3 **Q** And the Commission approved Duke's spending up to \$230
4 million in its efforts to incur preconstruction costs at
5 the Lee nuclear generation station; is that correct?

6 **A** [FALLON] I don't know if that's the exact words, but
7 that's approximately correct, yes.

8 **Q** Well, and if I may, drawing your attention to page seven
9 of that order, Finding No. 7, the finding states that,
10 "Duke Energy Carolinas incurred approximately \$70
11 million in project development costs through December
12 31, 2007. The company estimates that it will need to
13 incur up to \$160 million in Lee Nuclear Station project
14 development costs during the period January 1, 2008,
15 through December 31, 2009, in order to continue the
16 necessary preconstruction work to preserve the Lee
17 Station as an option in the 2018 timeframe." Have I
18 read that correctly?

19 **A** [FALLON] Yes.

20 **Q** And does that appear, from your understanding, to be a
21 correct statement?

22 **A** [FALLON] Yes.

23 **Q** And do you recall that the testimony before the
24 Commission in that docket from Ellen Ruff, who was in
25 the employ of Duke at the time, that Ruff testified that

1 Duke Energy Carolinas would not file an application with
2 the Public Service Commission of South Carolina for a
3 CPCN for the Lee Nuclear Station until the second
4 quarter of 2008, at the earliest. Do you see that on
5 page 27 of that order?

6 CHAIRMAN RANDALL: Mr. Elliott, make sure
7 you're keeping that Lavalier hanging in front of
8 you, because they can't hear you on the live-stream
9 sometimes.

10 MR. ELLIOTT: [Indicating.]

11 WITNESS FALLON: Yes, that's what it says.

12 BY MR. ELLIOTT:

13 Q And so it's fair to say that, at the time, Duke
14 anticipated filing for its certificate of public
15 convenience and necessity perhaps as early as the middle
16 of 2008; is that correct?

17 A [FALLON] Yes, that's correct.

18 Q But Duke, of course, never filed for a certificate of
19 public convenience and necessity in 2008, or ever, did
20 it?

21 A [FALLON] Yes, that's correct.

22 Q Now, you also testify about a subsequent proceeding in
23 2011 where Duke sought an amended project development
24 application. Do you recall that?

25 A [FALLON] Yes, I do.

1 Q And I showed this to counsel, and I'm going to put the
2 2011 order – 2011-454 – on the ELMO, just the front
3 page, and ask if that appears to be a copy of the 2011
4 order.

5 A [FALLON] Yes, it does.

6 Q Thank you. Now, in this proceeding, Duke sought to
7 amend the 2008 order. Do you recall that to be the
8 case?

9 A [FALLON] I don't know the exact legal process, but, yes,
10 we were coming in for an additional project development
11 order.

12 Q All right. And if you just look at the label here, it
13 says "Order Approving Amended Project Development
14 Application and Settlement Agreement." Do you see that
15 language?

16 A [FALLON] Yes.

17 Q And do you recall, in that case – or do you understand,
18 at least, if you don't recall in 2011 – that one of your
19 witnesses, Mr. Rogers, Chairman, President, and Chief
20 Executive Officer of Duke, testified, and I'm on page
21 10, and I'm about two-thirds of the way down the page,
22 and I've got it highlighted. However, he testified that
23 the company will not move forward with building the Lee
24 nuclear station until: one, the regulatory regime is in
25 place in North Carolina allowing recovery of financing

1 costs outside of a rate case in North Carolina, similar
2 to the provisions contained in the South Carolina BLRA;
3 two, the COL is in place; and, three, all necessary
4 approvals from state regulators are obtained.

5 Do you – were you there for that proceeding, or do
6 you recall that that was Mr. Rogers' testimony?

7 A [FALLON] Yes, I do.

8 Q Now, as I understand it, North Carolina has never seen
9 the wisdom of enacting a BLRA; is that correct?

10 A [FALLON] There is a project development statute in North
11 Carolina. It provides for recovery of construction
12 financing costs through a rate case, but not through an
13 annual mechanism. So that was the differential between
14 the two.

15 Q In North Carolina, I take it you don't get the upfront
16 approval of prudence of the decision to construct the
17 nuclear plants; you have to wait until the rate case to
18 get that approval?

19 A [FALLON] No, I don't believe that's the case. I believe
20 that the North Carolina statute – you can go in for a
21 prudence determination. The difference between the two
22 – I mean, I'm not the legal expert, that the primary
23 difference between the two statutes was the ability to
24 recover financing costs outside of a rate case, through
25 the tracker mechanism.

1 Q All right, sir. And drawing your attention to page 17
2 of the Order No. 2011-464, I ask you if the following –
3 A [FALLON] -454 or -464?
4 Q -454 –
5 A [FALLON] Okay.
6 Q – it looks like, from my order. I'd ask you if this is
7 a correct proposition: "The company must incur only
8 those costs absolutely necessary to keep the Lee nuclear
9 project available as an option in the 2021 timeframe.
10 The prudence determination made in this proceeding
11 applies only to the South Carolina allocable share of
12 the additional preconstruction costs of \$75 million
13 without AFUDC, not to exceed \$120 million with AFUDC,
14 for the period January 1, 2011, through June 30, 2012."
15 Have I read that correctly?
16 A [FALLON] Yes, you have.
17 Q And you understand that to be the order in this case,
18 don't you, sir? This is correct, correct?
19 A [FALLON] Yes.
20 Q I think in that docket, Duke came in and actually
21 applied for \$229 million in authority for
22 preconstruction costs; isn't that correct?
23 A [FALLON] I believe so, yes.
24 Q And the testimony at that time was that a total of \$459
25 – \$479 million would be sufficient – \$459 million would

1 be sufficient to get y'all through the period ending
2 June 30, 2012; is that correct?

3 A [FALLON] I don't think it was through June 30, 2012. I
4 believe it was through receipt of the COL, which I think
5 was an un- -- we were projecting in the 2013 timeframe,
6 at that point.

7 Q All right, sir. And so, but as a consequence, the
8 Public Service Commission in its order limited you to
9 \$120 million, through June 30, 2012; is that correct?

10 A [FALLON] Yes, it was pursuant to the settlement
11 agreement.

12 Q Right. And to be clear, the Commission approved the
13 settlement agreement, but you agreed to this order,
14 correct? Duke agreed to the terms of this order,
15 correct?

16 A [FALLON] Yes, and I believe that we've followed it
17 through the receipt of the COL and up to this point, so
18 yes.

19 Q And I do want to talk to you a little bit about that. I
20 mean, you think it's important to follow the existing
21 orders of the South Carolina Public Service Commission;
22 isn't that correct?

23 A [FALLON] Yes.

24 Q And I think you testified that, in so doing, that Duke
25 has consistently filed all of the quarterly

1 documentation required by this Commission in that Order
2 No. 2011-454; isn't that correct?

3 A [FALLON] To my knowledge, yes.

4 Q And you understand that the company has been filing
5 regularly a report with this Commission, saying that the
6 North Carolina General Assembly has not enacted a Base
7 Load Review Act or something similar. You recall those
8 filings, don't you?

9 A [FALLON] Yes.

10 Q And you recall, if for no other reason than from Ms.
11 Smith's testimony, that the company has been filing
12 these quarterly reports informing the Commission how
13 much they've spent on the preconstruction efforts for
14 the Lee nuclear station, correct?

15 A [FALLON] Yes, that's correct.

16 Q And I believe that you testified that, although Duke was
17 entitled or authorized to spend up to \$350 million on
18 preconstruction costs through June 30, 2012, Duke only
19 spent \$251 million during that period; isn't that
20 correct?

21 A [FALLON] Subject to check, yes.

22 Q And I think you testified that, after June 30, Duke has
23 spent about \$271 million after June 30, correct, of
24 2012?

25 A [FALLON] I think that's approximate. I'd have to look

1 at the numbers again.

2 Q Now, after June 30, 2012, Duke never came back in, under
3 Section 58-33-225, for any more authority to expend
4 costs for the preconstruction efforts at the Lee nuclear
5 station; isn't that correct?

6 A [FALLON] So, while that is correct, I think there's some
7 background information that would be beneficial here.
8 So if you look at the trajectory of this project, we
9 started out in the 2005 timeframe, after the Energy
10 Policy Act. There were significant financial benefits –
11 I mean, on the order of billions of dollars of
12 production tax credits – so we were pushing forward on
13 things like ordering long-lead equipment, site
14 excavation work, site prep, detailed engineering work.
15 And so when we came in for the first project development
16 order, a lot of those types of activities were included
17 in the costs.

18 When we came back in for the second project
19 development application, the project pivoted. We were
20 unable to come to an agreement on the EPC agreement with
21 Westinghouse and Shaw. And at that point, the
22 Commission told us in the order and in our settlement
23 agreement that we were to preserve the nuclear option
24 and we were only to spend those costs necessary to
25 deliver the project by the timeframes needed in our

1 Integrated Resource Plan, which at that time was in the
2 2021-2023 timeframe.

3 So that is exactly what we did, so we have followed
4 the settlement agreement and the Commission's order to
5 the letter, right? We ramped down spending, we didn't
6 commit any dollars to long-lead equipment, we didn't
7 commit any additional dollars. We only spent those
8 dollars necessary to keep the option available to deploy
9 this project in the 2021-to-2023 timeframe.

10 So with that as background, after we got – so after
11 that time period, since we believed that we were
12 following the order, we decided that we did not need to
13 come back in for an additional project order. We
14 decided not to. We didn't. And even in Section 3 that
15 you showed me earlier, that was a preauthorization for a
16 specific period of time. It doesn't represent a cap,
17 nor is it a requirement that we get that
18 preauthorization. It was just – that was a
19 preauthorization, and it doesn't guarantee you; it just
20 says that any additional dollars and work that we did
21 had to be deemed prudent, and I would think that no one
22 in this case has challenged the prudence of the work and
23 activities that we performed, and we've had other – in
24 North Carolina, they hired an independent party to come
25 in and evaluate the prudence of our activities and found

1 that we had done everything in a prudent manner, and the
2 North Carolina Commission found that our activities were
3 prudent.

4 **Q** Thank you. And North Carolina – I think they awarded
5 you some costs up there, but – nuclear construction
6 predevelopment costs – but they didn't authorize a
7 return on those costs, did they?

8 **A** [FALLON] The particular statutes that we were under in
9 North Carolina, they did not – it was – it was silent on
10 the matter. I think Duke – we disagreed with that
11 decision, but it was – the statute was specifically
12 silent on that matter and the Commission made their
13 decision.

14 **Q** So you would agree with me that the Commission didn't
15 award you a return on your preconstruction nuclear
16 development costs for Lee nuclear, correct?

17 **A** [FALLON] They did not – or, I mean, as I understand it,
18 they did not provide a return during the amortization
19 period, yes.

20 **Q** All right. So what I think I understood you to say was
21 that Duke didn't think it prudent to obtain an order of
22 this Commission authorizing it to spend a total of \$559
23 million in preconstruction development costs. Is that
24 your testimony?

25 **A** [FALLON] I don't believe that's what I said. I think

1 you're twisting the words a little bit there. What I
2 said was we were following an existing order, and we did
3 not see a need to come back in, because we felt that we
4 were in alignment. And as you asked me earlier did we
5 follow the Commission's orders, so we were following the
6 Commission's orders.

7 Q All right, sir. And we can agree that it's prudent to
8 follow the Commission's orders, can't we?

9 A [FALLON] Yes.

10 Q And we can agree that, if there's any question about the
11 need to file for an amended Base Load Review order, it
12 would be prudent to err in favor of applying for an
13 order to comply with the law, can't we?

14 A [FALLON] I'm sorry, I don't quite understand your
15 question. There were a few twists and turns.

16 Q We can agree it's prudent to follow the law, can't we?

17 A [FALLON] Yes.

18 Q Now, you understood Ms. Smith's testimony that as of
19 June 30, 2012, Duke had incurred approximately \$68
20 million in AFUDC; is that correct?

21 A [FALLON] I believe that was correct.

22 Q Well, and if I put the exhibit on the ELMO and point to
23 the \$68 million, would that help refresh your
24 recollection [indicating]?

25 A [FALLON] Yes.

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1 Q And so, today, you are asking for \$248 million in AFUDC?

2 A [FALLON] We are asking for the South Carolina allocable
3 portion of that amount, yes.

4 Q And – well, and the \$68 million is the systemwide AFUDC
5 as of June 30, 2012, correct?

6 A [FALLON] Yes, that's correct.

7 Q All right. So we can agree that from June 30, 2012,
8 until today, another \$180 million in finance charges
9 have accrued on your expenditures since – in the last
10 seven years?

11 A [FALLON] Yes, that's approximately correct.

12 Q And, again, it's your testimony that you didn't feel the
13 need to come in for an amended preconstruction review
14 order?

15 A [FALLON] I believe I said that, you know, we were
16 providing quarterly updates to the Commission, and we
17 believed that we were in compliance with the 2011 order.
18 And, as such, we elected not to come in for a
19 predetermination. Again, the order was for
20 preauthorization of costs; it did not say that any
21 specific costs were prudent, so we still had the same
22 burden to prove that the costs we spent and the work
23 that we did was done in a prudent manner, and I believe
24 that no one in this case has challenged the prudence of
25 our efforts, and North Carolina, as both an independent

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1 consultant and the Commission, has ruled that our
2 efforts were prudent.

3 **Q** And you did not ask for any recovery of these costs –
4 Duke did not ask for any recovery of these costs in its
5 2013 rate case either, did it?

6 **A** [FALLON] Not that I can recall. I don't know what the
7 mechanism would've been at that point in time, since it
8 was an ongoing activity and we were complying with the
9 Commission's order in the Commission's 2011 order.

10 **MR. ELLIOTT:** Thank you, very much.

11 Thank you, Mr. Chairman,

12 **CHAIRMAN RANDALL:** Thank you, Mr. Elliott.
13 Walmart?

14 **MS. GRUNDMANN:** No cross.

15 **CHAIRMAN RANDALL:** Okay. ORS.

16 **MR. NELSON:** No questions from ORS.

17 **CHAIRMAN RANDALL:** Thank you. Anybody I left
18 out?

19 [No response]

20 Commissioners. Commissioner Whitfield.

21 **COMMISSIONER WHITFIELD:** Thank you, Mr.
22 Chairman.

23 **EXAMINATION**

24 **BY COMMISSIONER WHITFIELD:**

25 **Q** Thank you both for your presentations. As Mr. Elliott

1 said, both of you gave a good recap, if you will, of the
2 history of the Lee nuclear site. And I've got just a
3 question, I guess mainly for you, Mr. Fallon – and maybe
4 one for you, Mr. Diaz, in a second. But I first must
5 say that Mr. Gharthey-Tagoe must have understood what I
6 meant when I misspoke, or either he was too nice to not
7 admit it, but what I said when I was talking about the
8 NRC licensing process, I was talking about the letter,
9 the notification that came about the public hearings. I
10 do realize that it was a much longer process than he and
11 I had the exchange, now. The original order for
12 preconstruction was just before I got on the Commission,
13 and so was the filing before the NRC, but I was here for
14 the 2011 order that was just discussed. And that said,
15 Mr. Fallon, you had a lot of discussion with Mr. Elliott
16 just now about this facility being in the IRP for many
17 years, and you, at least on one or two occasions, stated
18 that was for – in the 2021-to-2023 timeframe. And I'm
19 sure you probably know this, but South Carolina law, we
20 don't have quite the teeth in the IRP process that other
21 state commissions do. So, in your opinion, Mr. Fallon,
22 is it practical to consider the future use of that
23 reactor in light of the current climate with nuclear?
24 And also, is it still – do you still include it in the
25 IRP process, going forward?

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1 **A** [FALLON] I'll start with the first part of your
2 question, is, do I still think it may be built someday,
3 just to summarize, and I think, you know, Duke Energy
4 Carolinas has an obligation to plan for the long term,
5 you know, plan for safe, reliable, clean, and cost-
6 effective energy. And it's not just for next week, next
7 year, but it's for the next 50 to 100 years. So with
8 that as my background, I believe that Lee may be built
9 someday. Right? It's going to be — and we wouldn't
10 pursue it unless it was in the best interest of
11 customers.

12 I do know — or I believe, I should say, that a lot
13 of companies are looking to de-carbonize. I think our
14 country is looking to de-carbonize. And I believe, if
15 you're serious about decarbonizing, that nuclear has to
16 be part of the solution. We have an extremely well-run
17 nuclear fleet today and I hope that we can operate those
18 for many, many years into the future, with relicensing
19 and other opportunities. However, today, we don't know
20 what the cost of that option is. And if the Carolinas
21 still want to have a clean, reliable portfolio, then I
22 think nuclear could be a solution to that in the future,
23 and it provides us an option, depending upon what
24 happens with relicensing and government regulations and
25 customer demand growth, electric vehicles, any of those

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1 things that could drive it.

2 Q Well, I'm sure you're, obviously, watching the AP1000s
3 down in Georgia and the AP1000s that are being built in
4 other parts of the world, and watching kind of
5 curiously, and I guess taking notes of lessons learned.

6 A [FALLON] Yes, absolutely. So, part of our strategy, and
7 I think we were very consistent, once we couldn't get to
8 an EPC contract we said it was our desire to make a
9 decision with respect to the Lee project after receipt
10 of the COL. And the thought there was, you would have
11 experience from China, you would have experience from
12 V.C. Summer and Vogtle, the engineering. And probably
13 one of the challenges that all the first-mover plants
14 ran into was that engineering wasn't sufficiently
15 complete when they went to the field. So we wanted to
16 be third, so that we would be able to take advantage of
17 that. And so that's why I believe that the COL is a
18 valuable asset for Duke Energy Carolina customers.

19 You know, and the second part of your question
20 earlier was, is, do we still include it in the IRP. I
21 believe we do. It shows up only in certain scenarios
22 now, where you can't relicense and there's potential
23 carbon regulation. But we continue to evaluate whether
24 this asset would be in the best interest of our
25 customers.

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1 Q So sometimes being last is not a bad thing.

2 A [FALLON] No, absolutely – you know, once – earlier, I
3 talked about how we kind of got in the race, like
4 everybody else, because there was significant financial
5 benefits to being up first, which were called production
6 tax credits. And for a plant the size of Lee, they were
7 approximately \$2-\$2-1/2 billion of value that would have
8 accrued to the owners and the customers of those plants.
9 Once we didn't get any – you know, once we did not get
10 any EPC agreement and we weren't going to be able to
11 meet those deadlines, then we strongly believed that,
12 okay, we need to step back, learn the lessons, and
13 recapture some of that value by learning lessons from
14 the existing facilities.

15 Q Thank you, Mr. Fallon.

16 Mr. Diaz, what is the value of the COL of an
17 abandoned nuclear plant, of the probability of future
18 nuclear construction at the site is low? And a second
19 part of that, is it reasonable to assign value to the
20 asset which may not reasonably be expected to be used?

21 A [DIAZ] Well, the value of the COL, it lies in many
22 factors. One of the factors is how long it is. Nuclear
23 is not a short-term business. These plants that you
24 have now serving South Carolina and North Carolina are
25 about to be operated for at least 60 years, maybe 80.

1 So, contrary to other kind of permits – gas or coal –
2 that expire in two years or three years, the COL is
3 essentially non-expiring, because the 40 years would not
4 start until the time that you're building the plant.

5 You have the investment that was made into not only
6 obtaining the permit but into developing the site
7 suitable for large power production is preserved and
8 usable. And that is a value itself. It is not only
9 valuable, it is tangible and can be traded. It
10 continues to exist. It doesn't disappear.

11 And the value could be, you know, really
12 extraordinary if it comes to the point in which nuclear
13 occupies, you know, a rightful place in the commercial
14 production of electricity, which presently we all know,
15 due to the gas, it is not.

16 So it is a different animal. It's an animal that
17 provides the capability of building a plant when you
18 have the proper, you know, economics and the proper
19 technologies and the proper experience, when it can
20 benefit your customers the most. That is the intrinsic
21 value of it, and it's kind of unique.

22 The other, you know, tangible use is that you have
23 actually developed all the elements of a site, which
24 really has order, the location, the access to
25 transmissions. All those things that are necessary for

1 large production of power have been already cleared from
2 the environmental viewpoint, from the human population
3 viewpoint, from, you know, all of those aspects, and
4 including, you know, seismic or – everything you need to
5 do are there. So it is something of value. And, yes,
6 it is – many companies, large companies, have already
7 obtained and are keeping that value, because it could be
8 used. Nobody can guarantee it. You know, it would have
9 to be economically viable. I think that Duke made the
10 right decision to say, "I have a great asset, but I'm
11 not going to use it until it is beneficial to the people
12 of the Carolinas."

13 COMMISSIONER WHITFIELD: Thank you, Mr. Diaz.
14 That's all I have, Mr. Chairman, for this
15 panel.

16 CHAIRMAN RANDALL: Thank you.
17 Commissioner Hamilton.

18 COMMISSIONER HAMILTON: Thank you, Mr.
19 Chairman.

20 EXAMINATION

21 BY COMMISSIONER HAMILTON:

22 Q Mr. Fallon, I think you probably answered one of my
23 questions about your nuclear fleet. I assume that, from
24 your answer to Mr. Whitfield, that you'll continue to
25 attempt to license and relicense your nuclear fleet in

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1 the future?

2 A [FALLON] I think Mr. Capps is a witness who's going to
3 talk about nuclear, but what I will say is that I
4 believe all of our plants are good candidates for
5 relicensing, and we're strongly evaluating that. And no
6 one has -- I don't believe -- I've been out of the Nuclear
7 Department for a couple of years, but I think the first
8 wave of second license renewals are about to be
9 submitted here in the next year or two, so we'll know
10 more about that process as we get through that.

11 Q Thank you, sir. One other question I have for you -- and
12 you might want to look at your direct testimony. On
13 page six, the North Carolina Public Staff was concerned
14 with the costs associated with the Lee visitors' center,
15 as well as the AFUDC?

16 A [FALLON] Yes?

17 Q Okay. I think they disallowed the costs?

18 A [FALLON] Yeah, so, we had a slight disagreement over
19 whether or not the visitors' center was needed in order
20 to meet the deadlines in the IRP. The name, itself, was
21 part of the issue there, is that the idea was we were
22 developing a site or a building that was outside the
23 protected area where we would do initial construction
24 phase -- construction and engineering work on the site,
25 and then eventually turn it into a visitors' center.

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1 And so we had done some pre-engineering, or we hired an
2 architect and a design, to design that building. And it
3 was those specific costs – I think it was approximately
4 \$1/2 million worth of design work that we had done that
5 was excluded from the North Carolina rate case.

6 **Q** Okay, thank you, sir. Thank you, very much. Mr. Diaz,
7 happy to have you here with us, too, sir.

8 **A** [DIAZ] Yes, sir.

9 **COMMISSIONER HAMILTON:** Thank you, Mr.
10 Chairman.

11 **CHAIRMAN RANDALL:** Thank you.
12 Commissioner Belser.

13 **COMMISSIONER BELSER:** Thank you, Mr. Chairman.

14 **EXAMINATION**

15 **BY COMMISSIONER BELSER:**

16 **Q** Good afternoon.

17 **A** [PANEL] Good afternoon.

18 **Q** Mr. Fallon, following up briefly on what Commissioner
19 Hamilton just asked, with regard to the visitors'
20 center, and on a question that I had asked Ms. Smith
21 earlier, the visitors' center was one of those
22 exceptions from the North Carolina order, was it not,
23 that was removed?

24 **A** [FALLON] Yes.

25 **Q** And the other exceptions to the North Carolina order

1 that were removed from this were – do you recall?

2 **A** [FALLON] Non- – non-depreciated – the land, there were
3 some land costs that were pulled out, and then the
4 return component during the amortization period.

5 **Q** This is going to be real basic. Tell me what is at that
6 site. What are we talking about?

7 **A** [FALLON] You mean right now?

8 **Q** Yes.

9 **A** [FALLON] So, it's about 3000 acres of land. The former
10 Cherokee nuclear plant we had, there was partial
11 construction there. We had demolished that and we
12 pulled it down to the –

13 **Q** So they can't film another *Abyss* there?

14 **A** [FALLON] No, they can't.

15 [Laughter]

16 But there's dams, and there are access to – the
17 Broad River runs right by the site, so you have access
18 to water for plant operations. But, generally, it's
19 3000 acres and then we have another contract for the
20 supplemental cooling pond.

21 **Q** So what is taking – what is consuming all this money to
22 maintain that site? I mean, why – what work is being
23 done there to – all this money that's being spent?

24 **A** [FALLON] Which dollars are you specifically talking
25 about?

1 Q Well, that y'all are trying to recover.

2 A. [FALLON] The dollars we're trying to recover were the
3 work that we did to prepare the site to be able to
4 construct by 2021 to 2023, and then all of the licensing
5 work that we did. So we spent significant fees, let's
6 say it was \$25 million, developing the application, and
7 then I think it was about 125 – I'd have to look at my
8 testimony for the exact number, but in NRC review and
9 fees. So there was significant dollars, not specific to
10 the land and the facilities at the site, the warehouses
11 and such, but this was the work to get the application
12 reviewed by the NRC.

13 Q So after this case, and in the next rate case, are there
14 going to be requests for additional dollars? Or is this
15 the end right now?

16 A [FALLON] So, we have –

17 Q With regard to this site?

18 A [FALLON] So, we have a license for this site. So from
19 the NRC's perspective, it is an operating plant without
20 equipment. So there are certain regulatory requirements
21 that we have. It's very – it's relatively small. It's
22 approximately \$200,000 a year that are in mandatory
23 regulatory filings that we are projecting in costs for
24 this, that would just be part of our normal Nuclear
25 Department operating costs. So it's not significant.

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1 It's not -- there's no more --

2 Q They're just filing costs, not something, several
3 million dollars that would come out?

4 A [FALLON] No. No, there's an annual requirement to
5 update your final safety analysis report. And so the
6 individuals and the time they spend doing that work is
7 the cost, and any costs that the NRC sends us for their
8 review of it.

9 Q I made a note, and I had it in my written notes, and I'm
10 sorry I don't have the page number in your testimony.
11 But there was a sentence talking about reduced costs to
12 only those necessary, while preserving the ability to
13 resume work. So are there -- other than that filing with
14 the NRC that you just mentioned, are there going to be
15 activities at that site to come under that phrase I just
16 referred to or that I quoted?

17 A [FALLON] I mean, there may be some site maintenance,
18 mowing the lawn and -- but minimal, on an annual basis
19 type cost, right? We have -- I think we no longer have
20 the security there, but we have to do some minimal
21 maintenance. There's a dam on-site, so you have to do
22 inspections to make sure that, you know, it's safe. But
23 not -- like you said, these are, you know, thousands of
24 dollars, not millions of dollars type costs.

25 Q Thank you. Mr. Diaz, just a question or two, if I

1 might.

2 **A** [DIAZ] Yes.

3 **Q** You had discussion in your testimony about the TVA and
4 the Watts Bar site that had been discontinued back --
5 when was that -- in the '80s?

6 **A** [DIAZ] In the '80s. 1983, I believe.

7 **Q** And then they resumed in 2007-2008?

8 **A** [DIAZ] Yeah.

9 **Q** Is that correct?

10 **A** [DIAZ] About, yeah.

11 **Q** And then -- and one of those plants has actually been
12 completed?

13 **A** [DIAZ] It's completed and it's operating, yes.

14 **Q** Do you have any idea of what the cost implications or
15 what costs were expended with regard to that plant, from
16 the time it was abandoned until it was resumed?

17 **A** [DIAZ] There was a normal cost of maintaining, you know,
18 preserving the site. The license was suspended. The
19 license was reinstated. It was a different type of
20 license, but it was reinstated. And then the big cost,
21 of course, was building the reactor. The reactor was
22 about 50 percent built, and then they actually completed
23 it. And it cost a significant amount of money, like
24 \$4-1/2 billion.

25 **Q** For the construction of the plant?

1 A [DIAZ] Construction to operation, yes.

2 Q You testified about the intrinsic value of the COL, and
3 you stated, in response to a question from one of the
4 other Commissioners, I believe, when you have proper
5 economics to resume the plant. Based on your
6 experience, does it look like there will be a resumption
7 of construction of a nuclear plant at the Lee site?

8 A [DIAZ] My guess is just a guess, but the answer is, yes.
9 I consult in many places in the world, and this is not
10 the only place in the United States that have sites
11 under consideration. I'm working on another one of
12 those in Utah. Utah is now experiencing a phase in
13 which the coal plants are being retired, gas is coming
14 over. It's just becoming, you know, from a dependence
15 of coal to a dependence of gas. And so the answer is,
16 yes. The answer is that I believe that we have gone
17 through a system transformation that where coal was the
18 dominant fuel and nuclear was 20 percent of the
19 electricity, into which gas has now replaced coal as the
20 dominant fuel of the land, and there is now a dependence
21 of gas. We believe, in the industry – not only the
22 nuclear industry, but the energy industry – that it's
23 very important to have a portfolio of different
24 components. You cannot to depend on one fuel. And
25 nuclear has very attractive features. They're very

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1 costly to build, but they have a very steady and very
2 low production cost. So once you get it built, they
3 work for a long time and they work cheap, and
4 consistent, producing enormous amounts of energy,
5 stabilizes your grid. So there are a series of factors
6 that actually are favorable to nuclear.

7 Whether it will get there, if I had that crystal
8 ball, I, you know, would be making money on Wall Street.
9 But the reality is that I firmly believe that there is a
10 very good chance that, by the year 2028-2030, nuclear
11 will be in a position to restart and occupy a portion of
12 the energy infrastructure of the United States.

13 Q You were following that very closely, Mr. Fallon. Did
14 you have something to add to that?

15 A [FALLON] Well, I think – I thought his answer was very
16 good, and I think that, you know, again, you have to
17 look at our mission as a utility is to plan for the
18 long-term system and have options, depending upon what
19 comes up, whether it's carbon regulation, if plants
20 don't get relicensed. So this, I believe, is a very
21 valuable option for our customers because it allows us
22 to deploy nuclear in a much faster timeframe and it
23 allows us to significantly reduce the risks that some of
24 the first projects, like Vogtle and V.C. Summer,
25 experienced.

1 Q Mr. Diaz, because the combined operating license was
2 filed for the Westinghouse AP1000, is it correct that,
3 years from now, if resumption of the site – if it
4 resumed, if construction resumed, would it be limited to
5 that type of reactor?

6 A [DIAZ] It could, if you choose to do so. But it is not
7 exclusively limited. The applicant can, actually, at
8 the time, choose another reactor and go through the
9 process – it would take another four or five years, if
10 things –

11 Q That would have to start the process over, would it not?

12 A [DIAZ] Not – not completely. You will have a series of
13 portions of the license that will be applicable.
14 Everything regarding to the site, seismic, a lot of the
15 real, you know, steady factors will be there, and so you
16 will have something that exists and don't have to change
17 it. But, yes, everything – if you change the
18 technology, it will be a completely different
19 technological application. You'd have to rely on the
20 different, you know, certification of the safety of the
21 plant. So it would be different, but it is possible.
22 It has been done. There's a company that already
23 changed three times its reactor type in the United
24 States, in the last 15 years..

25 Q I guess I'm curious as to the costs that would be

1 incurred, but that will be a future proceeding. Okay.
2 Thank you both, very much.

3 A [DIAZ] Thank you.

4 CHAIRMAN RANDALL: Thank you.
5 Commissioner Ervin.

6 COMMISSIONER ERVIN: Thank you, Mr. Chairman.

7 EXAMINATION

8 BY COMMISSIONER ERVIN:

9 Q Mr. Fallon, I want to refer to your filed direct
10 testimony. Do you have it handy?

11 A [FALLON] Yes, I do. Let me -- [indicating].

12 Q All right. Would you turn to page 25, please? Let me
13 know when you get there.

14 A [FALLON] I am there.

15 Q If you look, beginning on line six, there was a question
16 asked, "How do the 2018 Base Load Review Act amendments
17 impact the Lee nuclear project?" And your answer was,
18 beginning on line eight --

19 A [FALLON] Sorry, did you say page 25?

20 Q Yes, sir. Could be page 23. I've got two different
21 references to it.

22 A [FALLON] All right. I'm there now.

23 Q You see it now?

24 A [FALLON] Yes.

25 Q Okay. So let me start over. The question you were

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1 asked is, "How do the 2018 Base Load Review Act
2 amendments impact the Lee nuclear project?" Do you see
3 that question?

4 A [FALLON] Yes, I do.

5 Q And your answer was, quote, "While I'm not a lawyer, I
6 have been advised that because DE Carolinas does not
7 currently have any requests made pursuant to Article 4,
8 Chapter 33, Title 58, pending before the Commission,
9 Duke Energy Carolinas is unable to request recovery of
10 the abandoned Lee Nuclear Project preconstruction costs
11 pursuant to South Carolina Code Annotated Section 58-33-
12 225(G)," end quote. Was that your testimony?

13 A [FALLON] Yes.

14 Q And so you're of the opinion that when the Base Load
15 Review Act was repealed in South Carolina, by what we
16 commonly refer to as Act 258, along with that went any
17 chance to recover costs for preconstruction in South
18 Carolina?

19 A [FALLON] I guess, the clarification -- I don't believe it
20 eliminated our ability to recover preconstruction costs.
21 I believe that we are unable to recover them under that
22 specific statute. And I'm not a lawyer; I'm an
23 engineer, but --

24 Q Well, how else would you recover them?

25 A [FALLON] I mean, there are -- I mean, there have been --

1 previously, when you cancel a project or abandon a
2 project, prior to the Base Load Review Act, there were
3 opportunities to recover costs of those projects.

4 Q But that was your testimony, that you are of the opinion
5 that they're unable to request recovery of the abandoned
6 Lee nuclear project?

7 A [FALLON] Pursuant to – I think there's a "pursuant to"
8 that specific statute or code.

9 Q Yes, sir. Okay. Well, just from a practical
10 standpoint, if the Base Load Review Act has been
11 repealed in South Carolina, and you made the application
12 under that Act, don't you lose the chance to come back?
13 Unless you got a pending request, which the company had
14 no request prior to the repeal of the Act, doesn't that
15 foreclose recovery?

16 A [FALLON] I don't believe so. I think it forecloses
17 recovery – again, I'm not a lawyer. But I think it
18 forecloses recovery in the terms of that particular
19 statute. However, I believe general South Carolina
20 statutes allow us to seek recovery of these costs.

21 Q Well, that's something we need to look into, don't you
22 agree? Examine that question further? Since you had
23 some doubts about it in your testimony?

24 A [FALLON] I don't – could you explain to me what my
25 doubts were?

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1 Q Well, you just said it couldn't be recovered, and so I
2 just took you at your word in your testimony, in that
3 portion.

4 A [FALLON] I don't mean to be dense, but I think I say the
5 costs can't be recovered pursuant to that specific
6 statute.

7 Q Okay.

8 A [FALLON] There are other statutes within –

9 Q All right. Do you know what they are?

10 A [FALLON] I'm not a lawyer.

11 Q Yes, sir. Is there someone who perhaps can tell us
12 later in the hearing?

13 A [FALLON] I think, even in, like, Mr. – the ORS
14 testimony, they point to specific statutes for the
15 treatment of these costs.

16 Q All right, sir.

17 A [FALLON] I don't remember the numbers.

18 Q Mr. Diaz, I, like you, am a dreamer, I think, at times –
19 and I'm also an optimist – but I think we can agree that
20 no one is going to build an AP1000 nuclear reactor
21 anytime soon in this country; is that true?

22 A [DIAZ] I am not sure. But I would say, in the next five
23 or six years, the answer is: You are correct. After
24 five or six years, I don't know. There are four nuclear
25 – four AP1000s operating in China. I –

1 Q Not in the US, though.

2 A [DIAZ] But there will be – most probably – be one in the
3 US by 2021, so –

4 Q Where's that?

5 A [DIAZ] Vogtle.

6 Q Yeah. They're behind schedule and way over budget, is
7 that right, at Vogtle?

8 A [DIAZ] That is correct.

9 Q And no end in sight.

10 A [DIAZ] Oh, yeah, there is an end in sight.

11 Q Well, who's gonna build it? Because Westinghouse is
12 bankrupt. Are there other companies out there that are
13 building that particular reactor?

14 A [DIAZ] Yes, sir.

15 Q Who?

16 A [DIAZ] Bechtel. And I know there are several other
17 architectural –

18 Q Yeah.

19 A [DIAZ] – leaders.

20 Q But it would take five years, as you testified earlier,
21 just to get a license.

22 A [DIAZ] It – but they have the license.

23 Q I understand they have one for an AP1000.

24 A [DIAZ] They have a license. They don't need to get
25 another license. They can finish and they can operate

1 the plant. They don't need – they don't need another
2 permit. It's done and over with.

3 Q And wasn't one consideration by Duke Energy Carolinas
4 the fact that the federal tax credits expired and are no
5 longer available, are they?

6 A [DIAZ] Well, they are. They just got renewed this –
7 precisely, this week, I believe.

8 Q Okay. So I'm learning something. They've been
9 reinstated.

10 A [DIAZ] Reinstated.

11 Q All right. At the same levels that they were before?

12 A [DIAZ] I think a little more.

13 Q Okay. That's good news. So a lot of things would have
14 to happen, though, for it to be economically feasible.
15 You would agree with that?

16 A [DIAZ] Yes, I certainly would agree with that.

17 Q As long as the price of natural gas is low, it's going
18 to be the primary go-to fuel. You agree with that?

19 A [DIAZ] If that's the only consideration, yes, but there
20 are other considerations in choice of fuel, and the
21 other considerations, we are seeing them coming, is the
22 potential effects on the environment, it's the CO₂, it's,
23 actually, you know, the fact that there is a need for a
24 series of different sources. You can't rely on one,
25 because, then, if something happens, just like what

1 happened to gas in the early 2000s where the price went
2 out of the roof and companies couldn't practically pay
3 the bills. So there are more than one consideration.

4 **Q** I understand. And I agree. It's always good to have a
5 diversified portfolio.

6 **A** [DIAZ] Absolutely.

7 **Q** Yeah. Thank you, sir, I appreciate you being here
8 today.

9 **A** [DIAZ] Thank you.

10 **CHAIRMAN RANDALL:** Thank you.

11 [Brief pause]

12 **EXAMINATION**

13 **BY CHAIRMAN RANDALL:**

14 **Q** Okay. And I have just one question, Mr. Fallon, on your
15 prefiled direct, on page 34.

16 **A** [FALLON] I'm there.

17 **Q** Okay. From line 18 through 22, you're talking – you
18 know, you talk about NCUC Public Staff. You say they
19 concluded the costs incurred by DE Carolinas in pursuit
20 of the COL, including costs associated with pre-
21 construction and site development, land and right-of-way
22 purchases, supply chain, construction planning and
23 detailed engineering, operational planning, and post-COL
24 costs were reasonable and prudent with little exception.

25 What were those exceptions, and associated costs?

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1 You probably told a little bit of that to Commissioner
2 Belser a minute ago, but I just want to make sure.
3 A [FALLON] Yes, that's exactly correct. It was costs
4 associated with the design of the visitors' center, the
5 \$500,000; it was the removal of non-depreciable land;
6 and then it was – well, that was just the costs, and
7 then there was another – the Public Staff only ruled on
8 those particular issues. So, it was those two items
9 that they found prudent, that were excluded from their
10 prudence finding.

11 CHAIRMAN RANDALL: Okay. Thank you.

12 Thank you, Dr. Diaz. I had a question but
13 everybody has asked the same question I was going
14 to, so, you're off the hook with me.

15 Any other questions? Commissioner Howard?

16 EXAMINATION

17 BY COMMISSIONER HOWARD:

18 Q I'll make this quick. And either one of you can answer.
19 What do you think is the future of the small nuclear
20 reactors?

21 A [DIAZ] How much time do I have?

22 [Laughter]

23 Q About a minute – less than a minute. The Chairman will
24 kill me, if you go over a minute.

25 A [DIAZ] The small nuclear reactors offer a complete

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1 different way of building a reactor. That's what they
2 offer. You can build it in a plant and you can
3 transport it and you can load it. So it tries to get
4 away from this massive deployment of people and supplies
5 that sometimes are not there. And so, it is a good
6 idea. A very good idea.

7 The issue is: How small is small? And that's what
8 the industry is dealing with. It is possible that a
9 reactor, which is an expensive machine to build – not so
10 much to operate, but to build it, it's expensive – below
11 a certain size, it becomes, you know, too expensive. So
12 that's the dilemma that is happening.

13 But I do believe that, eventually, as small
14 reactors are built in a plant, rather than on-site, and
15 they are completely done by craftsmen that do the same
16 thing day after day, would be extremely good and will
17 bring nuclear back in a different scale.

18 **Q** Thank you.

19 **A** [DIAZ] That's what I know of this.

20 **COMMISSIONER HOWARD:** Thank you, Mr. Chairman.

21 **CHAIRMAN RANDALL:** Thank you. I was gonna
22 tell Commissioner Howard, like I told my preacher
23 one time about the 12 o'clock hour. You can talk
24 as long as you want to, but I'm leaving at 4:30.

25 [Laughter]

1 Mr. Marzo, any redirect?

2 MR. MARZO: Mr. Chairman, I do. I can be done
3 by 4:30.

4 CHAIRMAN RANDALL: Go for it.

5 REDIRECT EXAMINATION

6 BY MR. MARZO:

7 Q I'll start with you, first, Dr. Diaz, and I'll go
8 backwards to forwards. I think Commissioner Ervin had
9 asked you some questions about future nuclear in the
10 United States, and there was a discussion about Vogtle.
11 Isn't it correct that, currently, Vogtle is working with
12 Bechtel as a member of the partner to build future
13 nuclear plants?

14 A [DIAZ] Yes.

15 Q And as of this point in time, are you aware what the
16 schedule is or how Vogtle is doing in terms of its
17 current schedule?

18 A [DIAZ] Yes, I believe that the last report that I read,
19 things were actually beginning to fall in line in
20 accordance with the schedule, and the schedule of 2021
21 for the first plant has been given as high as an 80
22 percent probability of occurrence, and 2022-2023 for the
23 second plant. So those things do presently, and, you
24 know, all I can do is go by what I received, is that
25 they are now working towards completion.

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1 Q And one last question on that point. In terms of
2 national support, are you aware that the Trump
3 administration, I believe, announced this week through
4 Secretary Perry, additional loan guarantees or
5 extensions of loan guarantees? Am I correct about that?

6 A [DIAZ] Yes, you are.

7 Q Mr. Fallon, you were also asked questions about the law
8 – and I realize you're not a lawyer, so I'm not going to
9 ask you to be a lawyer today, but you took advice of
10 counsel, I understand, in drafting your testimony.
11 Commissioner Ervin had asked you some questions, I
12 believe on page 25, question at line number six, which
13 was about the impact of the BLR repeal. If you would,
14 for me, if you would read the Q&A directly below it,
15 which starts on line 16 and talks about prior to
16 enactment of BLRA, the Commission had previously had
17 precedent in terms of recovery of abandoned plant. Is
18 that a correct –

19 A [FALLON] Yes.

20 Q – recitation of your testimony?

21 A [FALLON] Yes, it is.

22 Q So you talk about the precedent of the Commission even
23 prior to the BLRA, correct?

24 A [FALLON] Yes, that's correct.

25 Q And even within that precedent, there's nothing that

1 prevents a company from requesting, in this case – and I
2 know there are different positions, but from requesting
3 in this case a return on the unamortized balance,
4 correct?

5 A [FALLON] Yes, that's correct.

6 Q Now, you were asked several questions by Mr. Elliott
7 around the prior orders that actually came under the
8 project-development portion of the former BLRA. You
9 recall those?

10 A [FALLON] Yes, I do.

11 Q And he asked you some questions that would lead one to
12 believe that he's suggesting that the company did not
13 comply with, for example, the 2011 order. Do you recall
14 those questions?

15 A [FALLON] Yes, I do.

16 Q Okay. And I believe this morning, when he was talking
17 to Ms. Smith, he had asked some questions in relation to
18 there being a cap. Were you here for that?

19 A [FALLON] Yes, I was.

20 Q And does the word "cap" appear within the order from
21 2011?

22 A [FALLON] No, it does not.

23 Q Okay. And, in fact, if I look for the wording in 2011,
24 I believe the wording is the term "prudence
25 determination"? Is that the word that's used in that

1 order?

2 A [FALLON] Yes, that's correct. That was how the project
3 development application and order process worked, is
4 that you get a determination that the decision to incur
5 nuclear development costs was prudent, but they did not
6 approve specific costs.

7 Q And that's an advance determination, correct?

8 A [FALLON] Yes, that's correct.

9 Q So, is it your understanding or do you know if the
10 company would be required to get that, in order to incur
11 additional costs?

12 A [FALLON] No, I don't believe so. And if you look at the
13 timeframe between the 2008 order and the 2011 order,
14 there was a period of 2010 that was not covered by a
15 project development order, and the Commission said it
16 was not going to rule retrospectively that it was
17 prudent, but that continued pursuit of new nuclear was —
18 was in the customer's best interest. So I think we have
19 precedent that we had periods of time where we didn't
20 get preapproval and the Commission still believed that
21 it was prudent in our pursuit of new nuclear.

22 Q And is it the company's position that they continue to
23 comply with the 2011 order, even after the period of
24 time in which the predetermination amount had passed?

25 A [FALLON] Yes.

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1 Q Okay. And was the 2011 order based upon a settlement
2 between the parties?

3 A [FALLON] Yes, it was.

4 Q Okay. And I believe Mr. Elliott's client was one of the
5 settling parties; is that correct?

6 A [FALLON] Yes, I believe he signed the order -- or, the
7 settlement agreement.

8 Q Would you turn to the actual -- do you have the actual
9 settlement agreement that's appended to the order for
10 2011?

11 A [FALLON] I do.

12 Q Okay. Would you turn to page four of that settlement
13 agreement? And where I'm tempted to use the light --
14 which I don't get to -- I've not had a chance yet to
15 utilize, I will try to just try to work off the page,
16 which is page four, paragraph two.

17 MR. MARZO: And I'll be very brief, Mr.

18 Chairman; I just have a couple of quick questions
19 on this.

20 BY MR. MARZO:

21 Q When I look at this paragraph, this is particularly the
22 governing paragraph of what the company was required to
23 do as it pertains to the authority granted in 2011,
24 correct?

25 A [FALLON] Yes, that's correct.

1 Q If I look at this paragraph – and I'm going to ask you
2 to opine on this, Mr. Fallon. When I look at this
3 paragraph, one of the things the company was required to
4 do was to maintain the current schedule for obtaining
5 the combined operation license for the project in the
6 2021-through-2023 timeframe. And that's summarizing
7 what's there. Is that a fair summation of that
8 requirement?

9 A [FALLON] Yes. We were expected to continue to pursue
10 the license and any work that would be needed in order
11 to deliver the project by the 2021-to-2023 timeframe.

12 Q Okay. And did you do that?

13 A [FALLON] Yes, we did.

14 Q Okay. And if I look at the next requirement, it says
15 the parties agree that the Commission should allow only
16 the absolute minimum amount of dollars necessary to keep
17 the nuclear option available. Do you see that?

18 A [FALLON] Yes, that's correct.

19 Q Okay. Did you do that?

20 A [FALLON] Yes. So after this order, we significantly
21 reduced spending to just those activities that were
22 necessary to receive the license and to be in a position
23 to deploy the plant by the 2021-to-2023 timeframe in the
24 order.

25 Q And when it comes to the actual preapproval for

1 expenditures that was included in this order, did the
2 company stay within the preapproval amounts for the
3 timeframes listed?

4 A [FALLON] Yes. As we ramped down spending, recognizing
5 that we were no longer doing things like ordering long-
6 lead equipment and doing detailed design engineering, we
7 spent significantly less dollars and we came in during
8 the time period in the settlement well below the amounts
9 as stated in the settlement.

10 Q And understanding there may be some differences in terms
11 of whether or not a return should be earned on the
12 unamortized balance in this case, has any witness in
13 this case presented evidence to suggest that the
14 company's activities in pursuing the COL for the Lee
15 nuclear project were imprudent?

16 A [FALLON] No.

17 MR. MARZO: Thank you, Mr. Fallon.

18 Mr. Chairman, I have no further questions.

19 CHAIRMAN RANDALL: Thank you.

20 Any recross?

21 MR. ELLIOTT: Mr. Chairman, I have no recross,
22 but I think I would, at this time, like to ask the
23 Commission, in light of counsel's questions and
24 mine, to take judicial notice of Orders No. 2008-
25 417 and 2011-454 and any required filings submitted

1 by the company pursuant to those orders.

2 CHAIRMAN RANDALL: We will take judicial
3 notice.

4 MR. ELLIOTT: Thank you.

5 MR. MARZO: Thank you, Mr. Elliott, for doing
6 that. Thank you.

7 CHAIRMAN RANDALL: Commissioners?

8 EXAMINATION

9 BY COMMISSIONER ERVIN:

10 Q One follow-up question, Mr. Fallon. Since you own the
11 property and since you're on the river and have already
12 constructed a dam, I'm just curious, have you looked
13 into the possibility of retrofitting it, the site, for a
14 hydroelectric facility? Is that a possibility?

15 A [FALLON] I don't believe that's a possibility. I don't
16 think the flows in that – and it's just downstream of 99
17 Island, so it's – I don't think that's a real
18 possibility.

19 COMMISSIONER ERVIN: Thank you.

20 CHAIRMAN RANDALL: Commissioner Belser, you
21 had a question?

22 COMMISSIONER BELSER: No, I was just going to
23 – with regard to the request for judicial notice,
24 are you asking that those quarterly reports also be
25 included in that, Mr. Elliott?

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1 MR. ELLIOTT: Yes, ma'am.

2 COMMISSIONER BELSER: Could I ask that y'all
3 get together and submit a packet of the materials
4 that y'all are asking judicial notice? Because I
5 don't feel like going back and diving through the
6 DMS for those.

7 MR. ELLIOTT: Well, I think –

8 MR. MARZO: I'll let counsel talk first, but
9 if I can object, I mean, I think, based upon the
10 cross as heard by the Commission today, the primary
11 things that would need to be judicially noticed are
12 just the two orders. It would be the 2008 order
13 and the 2011 order. If that makes it easier for
14 the Commission to –

15 COMMISSIONER BELSER: And you said any
16 required filings submitted.

17 MR. ELLIOTT: Well, in particular –

18 MR. MARZO: I believe counsel asked for that.
19 And if time before – Commissioner, you recognize
20 the difficulty that that might create. I would
21 suggest that, based upon the cross, it would be
22 logical to just include the two orders which we
23 both used in cross-examination, rather than the
24 broader docket.

25 MR. ELLIOTT: Well, let me, in particular, ask

1 the Commission to take judicial notice of the
2 filing April 1, 2012, through June 30 –

3 CHAIRMAN RANDALL: If your mic is on, it's not
4 working. They can't hear you in the back, anyway.

5 MR. ELLIOTT: [Indicating.] Let's me amend my
6 request to seek judicial notice of simply the
7 quarterly filing that I cross-examined at least
8 one, or both, of these witnesses from: Duke Energy
9 Carolinas' report of Lee nuclear station activities
10 and expenditures, pursuant to the settlement
11 agreement in the second order, April 1, 2012,
12 through June 30, 2012.

13 MR. MARZO: I guess my concern, Commissioner
14 Belser, is that – or, Mr. Chairman and Commission,
15 is that we're taking judicial notice of an order;
16 that's one thing. We're now entering exhibits from
17 the docket; that's something different. If Mr.
18 Elliott had marked that and wanted to include it as
19 an exhibit, that's something we could deal with,
20 and I could make an objection if I wanted to at the
21 point in time it was moved. But to just take
22 judicial notice of an individual report is
23 different than when we're talking about just
24 orders. The orders of the Commission speak for
25 themselves and are orders.

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1 Mr. Chairman, if it makes it easier and Mr.
2 Elliott just wants to mark it, we won't object to
3 it as marked.

4 **CHAIRMAN RANDALL:** Okay.

5 **MR. ELLIOTT:** Uh –

6 **CHAIRMAN RANDALL:** You gonna object to it?
7 Because I'm agreeing with him on what he was
8 talking about. I don't think we need to get into
9 the additional thing, but we can mark it.

10 **MR. ELLIOTT:** And admit it as a hearing
11 exhibit? Certainly.

12 **CHAIRMAN RANDALL:** Okay.

13 **MR. MARZO:** No objection to that.

14 **CHAIRMAN RANDALL:** We'll do that, without
15 objection.

16 **MR. MARZO:** Mr. Chairman, for clarification,
17 what number is that?

18 **MR. DONG:** No. 19.

19 **MR. MARZO:** Thank you.

20 **CHAIRMAN RANDALL:** No. 19. Okay. Is there
21 anything else?

22 **MR. ELLIOTT:** May I provide a copy in the
23 morning, or at least provide a copy now and get a
24 copy back in the morning – or, no, I tell you what.
25 I'll give you this one, and I'll make my own copy

1 back at the office.

2 CHAIRMAN RANDALL: That would be a very good
3 plan.

4 [WHEREUPON, Hearing Exhibit No. 19 was
5 marked and received in evidence.]

6 MR. MARZO: Mr. Chairman, one last request,
7 and I apologize.

8 CHAIRMAN RANDALL: Yes, sir. Microphone.

9 MR. MARZO: My client would've probably fired
10 me. Mr. Fallon and Mr. Diaz, we'd like to ask that
11 they be released.

12 CHAIRMAN RANDALL: Absolutely. We thank you
13 gentlemen for your testimony, and you are excused.

14 [WHEREUPON, the witnesses were excused.]

15 Okay. All right. We'll start with your next
16 witnesses at 10 o'clock tomorrow morning. And we
17 are adjourned.

18 [WHEREUPON, at 4:33 p.m., the hearing in
19 the above-entitled matter was adjourned,
20 to reconvene on March 22, 2019, at 10:00
21 a.m.]

22
23 [WHEREUPON, in the absence of objection
24 by any party, Hearing Exhibits 17 and 18
25 were received in evidence: 4/5/2019]

1 testifying to today, correct?

2 A That is correct.

3 MR. MARZO: In addition, Mr. Chairman, with --
4 if I could take a little bit of liberty,
5 earlier this morning Mr. Robinson, I believe,
6 had referred to a witness, later in the
7 proceeding, that addressed some of the
8 questions that were asked about end-of-life
9 nuclear reserve, and I believe Mr. Doss may be
10 a witness who can help with that.

11 THE EXAMINATION BY MR. MARZO CONTINUES.

12 Q Mr. Doss, there were some questions this morning,
13 with the first panel round, end-of-life nuclear
14 reserve. I think you may've been here for that; is
15 that correct?

16 A Yes. I was.

17 Q All right. And I believe one of the questions from
18 more than one commissioner was around the return
19 that may be accrued on that particular reserve for
20 customers. Did you hear those questions?

21 A I did hear those questions.

22 Q Could you please give an answer to that question,
23 as you understand it, coming from the Commission?

24 A Yes. So, with that, if we're collecting money from
25 customers and holding it in reserve, those

1 customers would reserve -- would receive a return
2 on those -- on those amounts.

3 MR. MARZO: Thank you, Mr. Doss. Mr.
4 Chairman, I have no further questions.

5 CHAIRMAN RANDALL: Thank you. Any re-cross?

6 MR. NELSON: I just want to follow up on that
7 real briefly.

8 CHAIRMAN RANDALL: Okay.

9 RE-CROSS-EXAMINATION

10 BY MR. NELSON:

11 Q Mr. Doss -- sorry -- so there's going to -- it's a
12 return. What -- how much return, and how is that
13 actually given back to ratepayers?

14 A So the mechanics of this would be that the -- we
15 would establish a regulatory liability as we are
16 collecting those costs. And the way that we build
17 our rates is the regulatory liability is actually a
18 reduction of our rate base, and that's the method
19 through which customers would earn a return on
20 this.

21 Q How much of a return? What -- what is that based
22 on? Is that --

23 A It would be based on the -- the level of return
24 that we earn on our rate base.

25 Q All right.

1 **DIRECT TESTIMONY AND EXHIBITS OF**
2 **DAVID C. PARCELL**
3 **ON BEHALF OF**
4 **THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF**
5 **DOCKET NO. 2018-319-E**
6 **IN RE: APPLICATION OF DUKE ENERGY CAROLINAS, LLC**
7 **FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS AND**
8 **REQUEST FOR AN ACCOUNTING ORDER**
9

10 **I. INTRODUCTION**

11 **Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.**

12 **A.** My name is David C. Parcell. I am a Principal and Senior Economist of Technical
13 Associates, Inc. My business address is Suite 130, 1503 Santa Rosa Rd., Richmond,
14 Virginia 23229.

15 **Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**
16 **PROFESSIONAL EXPERIENCE.**

17 **A.** I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia
18 Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from
19 Virginia Commonwealth University. I have been a consulting economist with Technical
20 Associates since 1970. I have provided cost of capital testimony in public utility
21 ratemaking proceedings dating back to 1972. In this regard, I have previously filed
22 testimony and/or testified in over 570 utility proceedings before about 50 regulatory

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1 reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of
2 return on the assets utilized (*i.e.*, rate base) in providing service to their customers.

3 The rate base is derived from the asset side of the utility's balance sheet as a dollar
4 amount and the rate of return is developed from the liabilities/owners' equity side of the
5 balance sheet as a percentage. Thus, the revenue impact of the cost of capital is derived by
6 multiplying the rate base by the rate of return, including income and other taxes.

7 The rate of return is developed from the cost of capital which is estimated by
8 weighting the capital structure components (*i.e.*, debt, and common equity) by their
9 percentages in the capital structure and multiplying these values by their cost rates. This
10 is also known as the weighted cost of capital.

11 Technically, "fair rate of return" is a regulatory and accounting concept that refers
12 to an *ex post facto* (after the fact) earned return on an asset base while the cost of capital is
13 an economic and financial concept which refers to *ex ante facto* (before the fact) expected,
14 or required, return on a capital base. In regulatory proceedings, however, the two terms
15 are often used interchangeably, and I have equated the two concepts in my testimony.

16 From an economic standpoint, a fair rate of return is normally interpreted to mean
17 that an efficient and economically-managed utility will be able to maintain its financial
18 integrity, attract capital, and establish comparable returns for similar risk investments.
19 These concepts are derived from economic and financial theory and are generally
20 implemented using financial models and economic concepts.

21 With regard to the regulatory standards, my testimony is based on my
22 understanding that two United States Supreme Court decisions provide the controlling
23 standards for a fair rate of return. The first decision is *Bluefield Water Works and*

1 *Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923). In this
2 decision, the Court stated:

3 The annual rate that will constitute just compensation depends upon many
4 circumstances and must be determined by the exercise of fair and
5 enlightened judgment, having regard to all relevant facts. A public utility
6 is entitled to such rates as will permit it to earn a return on the value of the
7 property which it employs for the convenience of the public equal to that
8 generally being made at the same time and in the same general part of the
9 country on investments in other business undertakings which are attended
10 by corresponding risks and uncertainties; but it has no constitutional right
11 to profits such as are realized or anticipated in highly profitable enterprises
12 or speculative ventures. The return should be reasonably sufficient to assure
13 confidence in the financial soundness of the utility, and should be adequate,
14 under efficient and economical management, to maintain and support its
15 credit and enable it to raise the money necessary for the proper discharge of
16 its public duties. A rate of return may be reasonable at one time, and
17 become too high or too low by changes affecting opportunities for
18 investment, the money market, and business conditions generally.

19 It is generally understood that the *Bluefield* decision established the following
20 standards for a fair rate of return: comparable earnings, financial integrity, and capital
21 attraction. It also noted that required returns change over time, and there is an underlying
22 assumption that the utility be operated efficiently.

23 The second decision is *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S.
24 591 (1942). In that decision, the Court stated:

25 The rate-making process under the [Natural Gas] Act, *i.e.*, the fixing of 'just
26 and reasonable' rates, involves a balancing of the investor and consumer
27 interests. . . . From the investor or company point of view it is important
28 that there be enough revenue not only for operating expenses but also for
29 the capital costs of the business. These include service on the debt and
30 dividends on the stock. By this standard the return to the equity owner
31 should be commensurate with returns on investments in other enterprises
32 having corresponding risks. That return, moreover, should be sufficient to
33 assure confidence in the financial integrity of the enterprise, so as to
34 maintain its credit and to attract capital.

1 The Commission has looked to the *Hope* and *Bluefield* standards as guidance for
2 setting rates. For example, in both Docket No. 2013-59-E, a Duke Energy Carolinas rate
3 case from 2013, and in Docket No. 2016-227-E, a Duke Energy Progress, LLC rate case
4 from 2016, the Commission stated:

5 In setting rates, the Commission must determine a fair rate of return that the
6 utility should be allowed the opportunity to earn after recovery of the
7 expenses of utility operations. The legal standards applicable to this
8 determination are set forth in *Fed. Power Comm'n v. Hope Natural Gas Co.*,
9 320 U.S. 591, 602-603 (1944) and *Bluefield Water Works and*
10 *Improvement Co. v. Pub. Serv. Comm'n of W. VA.*, 262 U.S. 679, 692-93
11 (1923). These standards were adopted by the South Carolina Supreme Court
12 in *Southern Bell Tel. & Tel. Co. v. S.C. Pub. Serv. Comm'n*, 270 S.C. 590,
13 595-96, 244 S.E.2d 278, 281 (1978). The Court stated:

14 What annual rate will constitute just compensation depends upon many
15 circumstances, and must be determined by the exercise of a fair and
16 enlightened judgment, having regard to all relevant facts. A public utility is
17 entitled to such rates as will permit it to earn a return on the value of the
18 property which it employs for the convenience of the public equal to that
19 generally being made at the same time and in the same general part of the
20 country on investments in other business undertakings which are attended
21 by corresponding risks and uncertainties; but it has no constitutional right
22 to profits such as are realized or anticipated in highly profitable enterprises
23 or speculative ventures. The return should be reasonably sufficient to assure
24 confidence in the financial soundness of the utility and should be adequate,
25 under efficient and economical management, to maintain and support its
26 credit and enable it to raise the money necessary for the proper discharge of
27 its public duties...

28 Southern Bell Tel., 270 S.C. at 595-96, 244 S.E.2d at 281 (quoting
29 *Bluefield*, 262 U.S. at 692-93). These cases also establish that the process
30 of determining rates of return requires the exercise of informed judgment
31 by the Commission. The South Carolina Supreme Court has held that:

32 [T]he Commission was not bound to the use of any single formula or
33 combination of formulae in determining rates. Its ratemaking function,
34 moreover, involves the making of 'pragmatic adjustments' . . . Under the
35 statutory standard of 'just and reasonable' it is the result reached not the
36 method employed which is controlling. . . . The ratemaking process under

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the Act, *i.e.*, the fixing of ‘just and reasonable’ rates, involves the balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that ‘regulation does not insure that the business shall produce net revenues.’ . . . [B]ut such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on debt and dividends on the stock. . . . By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Southern Bell Tel., 270 S.C. at 596-97, 244 S.E. 2d at 281 (quoting Hope Natural Gas Co., 320 U.S. at 602-03). These principles have been employed by the Commission and the South Carolina Courts consistently.

The three economic and financial parameters in the *Bluefield* and *Hope* decisions – comparable earnings, financial integrity, and capital attraction – reflect the economic criteria encompassed in the “opportunity cost” principle of economics. The opportunity-cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity-cost principle is consistent with the fundamental premise on which regulation rests, namely, that it is intended to act as a surrogate for competition.

Q. HOW CAN THE *BLUEFIELD* AND *HOPE* PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?

A. Neither the courts nor economic/financial theory has developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated. However, there are several useful models that can be employed

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1 **A.** It has long been my practice to develop my own independently determined proxy
2 group and to also conduct cost of equity analyses on the utility witness' proxy group. My
3 conclusions and recommendations, in turn, are based upon my review of the results of both
4 proxy groups.

VIII. DCF ANALYSIS

6 Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DCF
7 MODEL?

8 **A.** The DCF model is one of the oldest and most commonly-used models for
9 estimating the ROE for public utilities. The DCF model is based on the “dividend discount
10 model” of financial theory, which maintains that the value (price) of any security or
11 commodity is the discounted present value of all future cash flows.

The DCF model is based upon two fundamental principles. First, DCF is based on the postulate that investors value an asset on the basis of the future cash flows (*i.e.*, dividends and ultimate sales in the case of common stocks) they expect to receive from owning the asset. The second DCF principle is that investors value a dollar received in the future less than a dollar received today (*i.e.*, the “time value of money”). Within this context, the current price of a company’s stock is equal to the present value equivalent of the expected dividends and the proceeds from eventually selling the stock. The discount rate that equates the future anticipated dividends and future anticipated selling price with the current market price is the cost of common equity.

The DCF model is based upon the concept that the value of a share of stock is the discounted present worth of all the dividends to be received on that share. The DCF equation is:

1 called as witnesses, who, having been first duly
2 affirmed, were examined and testified as follows:

3 MR. BURNETT: (To the court reporter) Thank
4 you.

5 DIRECT EXAMINATION

6 BY MR. BURNETT:

7 Q Good morning, still, I think, Mr. Kerin. I'll
8 start with you. Will you please state your name
9 and your business address?

10 A (KERIN) Jon F. Kerin, 411 Fayetteville Street,
11 Raleigh, North Carolina.

12 Q By whom are you employed and in what capacity?

13 A (KERIN) Employed by Duke Energy Business Services.
14 I'm the vice president of operations, maintenance,
15 and governance for the CCP group.

16 Q And would you tell the Commission what "CCP" means?

17 A (KERIN) Coal-combustion products.

18 Q Did you cause to be prefiled in this docket, on
19 November 8, 2018, 39 pages of direct testimony in
20 question-and-answer form and an appendix consisting
21 of 38 pages and 10 exhibits consisting of 451
22 pages?

23 A (KERIN) I did.

24 Q Did you cause to be filed in this docket, on
25 January 23, 2019, an errata to your direct

1 testimony?

2 A (KERIN) I did.

3 Q Do you have any changes or corrections to that
4 direct testimony or these exhibits?

5 A (KERIN) No. I do not.

6 Q If I were to ask you the same questions that appear
7 in your direct testimony today, would your answers
8 be the same?

9 A (KERIN) They would.

10 Q Did you also cause to -- to be prefiled in this
11 docket, on March 12th of this year, 22 pages of
12 rebuttal testimony in question-and-answer form?

13 A (KERIN) I did.

14 Q Do you have any changes or corrections to that
15 rebuttal testimony?

16 A (KERIN) No. I do not.

17 Q If I were to ask you the same questions that appear
18 in your rebuttal testimony today, would your
19 answers be the same?

20 A (KERIN) They would.

21 MR. BURNETT: Mr. Chairman, at this time, I
22 would move that the prefiled direct and
23 rebuttal testimony of Mr. Kerin be copied into
24 the record as if given orally from the stand.

25 CHAIRMAN RANDALL: Mr. Kerin's prefiled direct

1 and prefiled rebuttal testimony will be
2 entered into the record as though given orally
3 from the stand.

4 MR. BURNETT: Mr. Chairman, I would also ask
5 that Mr. Kerin's exhibits be marked for
6 identification and entered into the records as
7 a composite.

8 CHAIRMAN RANDALL: Mr. Kerin's exhibits will
9 be marked and entered into the record as
10 Exhibit Number 29.

11 (WHEREUPON, Hearing Exhibit 29 was
12 marked and received in evidence.)

13 THE EXAMINATION BY MR. BURNETT CONTINUES.

14 Q Now, Dr. Wright, to you, sir, would you please
15 state your name and business address?

16 A (WRIGHT) Julius A. Wright, 18 Edgewater Drive,
17 Cartersville, Georgia.

18 Q By whom are employed and in what capacity?

19 A (WRIGHT) I'm the president of J.A. Wright and
20 Associates.

21 Q Did you cause to be prefiled in this docket, on
22 November 8, 2018, 28 pages of direct testimony, in
23 question-and-answer form, and one exhibit
24 consisting of 16 pages?

25 A (WRIGHT) Yes. I did.

1 Q Did you also cause to be filed in this docket, on
2 February 11, 2019, an errata to your direct
3 testimony?

4 A (WRIGHT) Yes.

5 Q Do you have any changes or corrections to that
6 direct testimony?

7 A (WRIGHT) I do not.

8 Q If I were to ask you the same questions that appear
9 in your direct testimony today, would your answers
10 be the same?

11 A (WRIGHT) Yes.

12 Q Did you also cause to be prefiled in this docket,
13 on March 12th of this year, 39 pages of rebuttal
14 testimony in question-and-answer form?

15 A (WRIGHT) Yes.

16 Q Do you have any changes or corrections to that
17 rebuttal testimony?

18 A (WRIGHT) I do not.

19 Q If I were to ask you the same questions that appear
20 in your rebuttal testimony today, would your answers
21 be the same?

22 A (WRIGHT) Yes. They would.

23 MR. BURNETT: Mr. Chairman, at this time, I'd
24 move that the prefiled direct and rebuttal
25 testimony of Dr. Wright be copied into the

1 record as if given orally from the stand.

2 CHAIRMAN RANDALL: Dr. Wright's prefiled
3 direct and rebuttal testimony will be entered
4 into the record as though given orally from
5 the stand.

6 MR. BURNETT: Mr. Chairman, I'd ask that Dr.
7 Wright's one exhibit be marked for
8 identification and entered into the record.

9 CHAIRMAN RANDALL: Dr. Wright's exhibit will
10 be marked and entered into the record as
11 Hearing Exhibit Number 30.

12 (WHEREUPON, Hearing Exhibit 30 was marked
13 and received in evidence.)

14 THE EXAMINATION BY MR. BURNETT CONTINUES.

15 Q Mr. Kerin, back to you. Do you have summaries of
16 your direct and rebuttal testimony?

17 A (KERIN) Yes. I do.

18 Q Would you please give them to the Commission?

19 A (KERIN) I will.

20 My direct testimony presents Duke Energy
21 Carolinas, LLC's, request for recovery of expenses
22 that the Company incurred between January 1, 2015,
23 and September 30th, 2018, to comply with
24 environmental requirements for the disposal of coal
25 combustion residuals, or CCRs. Duke Energy

1 Carolinas' request does not include any costs that
2 have been incurred related to fines, penalties, or
3 guilty pleas related to CCRs, or any costs
4 associated with events related to those fines,
5 penalties, or guilty pleas. My testimony also
6 presents Duke Energy Carolinas' supplemental
7 request for recovery of CCR compliance costs
8 incurred from October 1, 2018, through December 31,
9 2018.

10 CCR disposal regulations and industry
11 practices have evolved significantly over almost a
12 century of providing electric service from coal-
13 fired plants. During this evolution, Duke Energy
14 Carolinas has consistently complied with the CCR
15 disposal standards that were in place at the time.
16 Based on industry developments that occurred in the
17 1950s, the enactment of the Clean Air Act in the
18 1970s and its amendment in the 1990s, and the
19 enactment of the Clean Water Act in 1972, along with
20 the creation of the National Pollution Discharge
21 Elimination System, or NPDES, permitting program,
22 wet ash handling and ash basins were the primary
23 lawful and effective way to meet CCR needs and the
24 environmental requirements in years prior to the
25 advent of today's requirements. In many cases, ash

1 basins were actually created or relied upon to
2 effectuate prior environmental regulations. With
3 each evolution in these environmental regulations,
4 the Company has changed how it's operated its coal-
5 fired stations to comply accordingly. And, at each
6 step in this environmental regulatory evolution
7 process, the Company has been in line with industry
8 standards and has reasonably and prudently managed
9 CCRs and its coal ash basins.

10 The latest evolution in these requirements,
11 the Federal Environmental Protection Agency's CCR
12 Rule, as well as state-specific regulations and
13 oversight in the Company's service territories, has
14 occurred since the Company's last rate case. DEC
15 is now subject to new federal and state regulations
16 that require it to take significant action to
17 modify its operations, and, as a result, incur
18 substantial new expenditures associated with those
19 modifications. All the Company's ash basins must
20 be closed under either the CCR rule, state-specific
21 regulations and oversight, or both. All closure
22 plans must be approved by respective state
23 agencies. The Company has begun the process of
24 closing or submitting plans to close its ash basins
25 in accordance with its regulatory obligations.

1 The actions and decisions that DEC has taken
2 in order to comply with federal and state
3 regulatory requirements, including the Company's
4 current and future compliance activities and
5 solutions, have been reasonable, prudent, and cost-
6 effective given the individual characteristics of
7 each plant and basin site.

8 This concludes my summary of my direct
9 testimony.

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22 (PURSUANT TO PREVIOUS INSTRUCTION,
23 THE PREFILED DIRECT TESTIMONY,
24 INCLUDING CORRECTION/AMENDMENT,
25 OF JON F. KERIN FOLLOWS.)

**BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA**

DOCKET NO. 2018-319-E

IN THE MATTER OF:

Application of Duke Energy Carolinas, LLC	)	DIRECT TESTIMONY OF
For Adjustments in Electric Rate Schedules	)	JON F. KERIN
and Tariffs	)	FOR DUKE ENERGY
	)	CAROLINAS, LLC

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Jon F. Kerin. My business address is 411 Fayetteville Street, Raleigh, North Carolina, 27601-1849. I am employed by Duke Energy Business Services, LLC, as Vice President, Coal Combustion Products ("CCP") Operations, Maintenance and Governance. In this docket, I am testifying on behalf of Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company"). As more fully discussed below, my responsibilities have included providing governance and operations leadership to Duke Energy Corporation's ("Duke Energy") regulated operating companies, including DE Carolinas. Relevant to this testimony, during 2014, I held the position of General Manager in the Ash Basin Strategic Action Team – referred to as "ABSAT." I was named to my current role in 2015. In July 2018, I assumed additional responsibilities in the CCP organization, taking on responsibility for the Operations and Maintenance division.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree from the University of Maryland. I have over 30 years of experience in the electric utility industry, where I have been involved in various complex and challenging projects. In addition to my CCP experience, my background includes experience at various nuclear electric generating power plants and in other corporate functions. Prior to the merger of Progress Energy, Inc. and Duke Energy, I was the Director of the Project Management Center of

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1 Excellence for Progress Energy, Inc. After the merger, I became General
2 Manager, Performance Improvement in the Project Management and Construction
3 Department before transitioning to the ABSAT team. In these roles, I worked
4 with new project implementation and construction teams to ensure that major
5 compliance projects and major construction projects were planned, executed, and
6 completed in a reasonable, prudent, and cost-effective manner as required by
7 regulatory bodies in Duke Energy's regulated jurisdictions. In these roles, I
8 worked on and provided advice and leadership to over a dozen major projects
9 with combined costs exceeding \$5 billion. I also led efforts to develop and
10 establish enterprise-wide procedures to ensure all regulated projects were
11 completed in a prudent and cost-effective manner.

12 **Q. WHAT WAS THE PURPOSE OF THE ASH BASIN STRATEGIC ACTION**
13 **TEAM?**

14 **A.** The ABSAT team was the umbrella organization created for Duke Energy
15 companies to address the laws, regulations, and orders concerning the
16 management of coal combustion residuals ("CCR").¹ These new compliance
17 requirements apply to electric generating sites with new and existing CCR
18 landfills and surface impoundments (collectively "CCR units"), and impose new
19 obligations regarding landfill design, structural integrity design and assessment
20 criteria for CCR basins, groundwater monitoring and protection procedures,
21 closure of impoundments, and operational and reporting procedures for the

¹ CCR refers to fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from burning coal for the purpose of generating electricity by electric utilities. 40 C.F.R. § 257.53.

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1 disposal and management of CCR. This work has now been absorbed into the
2 CCP organization.

3 During my work on the ABSAT team, I spent approximately 3,000 hours
4 working exclusively on CCR issues. During this time, I reviewed and became
5 familiar with relevant state and federal regulations dealing with CCR issues as
6 detailed further in my testimony and as set out in Kerin Exhibit 1. I also studied
7 and became knowledgeable on historical industry practices and standards to
8 comply with these regulations. As part of this process, I interviewed legacy
9 employees in Fossil Hydro Operations, Environmental Health and Safety, and
10 Central Engineering who worked at, and with, coal combustion generating units
11 and CCR handling sites. I reviewed historical company documents dealing with
12 these facilities and sites to gain an understanding of how CCR handling standards
13 inside and outside of the Company have developed over time. I also interviewed
14 legacy employees at other Southeast utilities including Dominion Energy, AEP,
15 TVA, and Southern Company.

16 As part of my duties on the ABSAT team, I toured and inspected every
17 CCR basin in Duke Energy's North and South Carolina jurisdictions. I also
18 toured and examined other CCR units at Duke Energy's Midwest sites, and
19 Dominion Energy, AEP, TVA, and Southern Company sites. During my tenure on
20 the ABSAT team, I developed CCR evaluations for each of Duke Energy's CCR
21 sites and, where applicable, worked on developing comprehensive work plans
22 when work was needed on any of those sites. In the course of my duties, I also
23 interfaced with other utilities to discuss and enhance mutual understandings on

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1 evolving industry standards relating to CCR issues, and shared and received best
2 practices across the electric industry. I developed an industry peer group to
3 discuss CCR issues, which meets semi-annually and includes companies such as
4 Dominion and Southern Company. In this capacity, I also gained an
5 understanding and knowledge of coal ash management practices at utilities across
6 the country.

7 **Q. WHAT ARE YOUR PRIMARY RESPONSIBILITIES AS THE VICE**
8 **PRESIDENT, OPERATIONS, MAINTENANCE, AND GOVERNANCE?**

9 **A.** I am responsible for regulatory affairs, operations support, and other centralized
10 CCR functions. My team works to define, establish, and maintain fleet CCP
11 standards, programs, processes, and best practices within functional areas for all
12 fossil plant sites. My team also oversees site operations and maintenance
13 ("O&M") of CCP facilities, including CCR and high-hazard dam operations and
14 maintenance, production landfills, decommissioning and demolition, and
15 byproducts management.

16 In my current role, virtually 100 percent of my time is dedicated to CCR
17 oversight, compliance, operations, maintenance, and project execution activities.
18 I have continued to review and study evolving rules and regulations related to
19 CCR issues. I have also maintained my presence in industry peer groups
20 regarding CCR issues and continue to help monitor, develop, and implement
21 industry best practices and standards for CCR issues.

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1 **Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?**

2 A. Yes. I filed direct testimony regarding CCR issues in Duke Energy Progress,
3 LLC's ("DE Progress") rate case in South Carolina in Docket 2016-227-E and
4 appeared before the Public Service Commission of South Carolina in October
5 2016 in connection with that case. I also filed direct and rebuttal testimony
6 regarding CCR issues in DE Progress' and DE Carolinas' recent North Carolina
7 rate cases in Docket Nos. E-2, Sub 1142 and E-7, Sub 1146, respectively, and
8 testified before the North Carolina Utilities Commission in connection with those
9 cases.

10 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

11 A. DE Carolinas is seeking recovery of CCR expenses incurred from January 2015
12 through ~~August~~ ^{September} 2018 and estimated costs to be incurred ~~September~~ ^{October} 2018 through
13 December 2018 related to compliance with applicable regulatory requirements.
14 The purpose of my testimony is to explain those regulatory requirements and to
15 explain how our compliance actions and decisions, including our current plans to
16 meet existing legal requirements, have been and continue to be reasonable,
17 prudent, and cost-effective approaches to comply with those regulatory
18 requirements.

19 **Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.**

20 A. DE Carolinas has become subject to both federal and state regulatory
21 requirements that mandate closure of its ash basins and other ash storage areas.
22 Since the early 1900s, DE Carolinas has disposed of CCR in compliance with
23 then-current regulatory requirements and industry practices. Until the 1950s,

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1 CCR were either emitted through, in the case of fly ash, smokestacks or, in the
2 case of bottom ash, manually removed from boilers and stored in fill areas. Since
3 that time, the industry transitioned to wet sluicing using water to remove ash from
4 boilers, and to clean the electrostatic precipitators ("ESP"), preventing ash from
5 being emitted through the smokestacks. This effluent, as well as flue gas
6 desulfurization ("FGD") blowdown, was then diverted to ash basins, or
7 impoundments. DE Carolinas has 17 ash basins in the Carolinas.

8 In the mid-1970s, the enactment of the Clean Air Act (42 United States
9 Code §7401 et seq.) and its subsequent amendment in the 1990s required electric
10 utilities to capture more CCR through the use of ESP or bag houses and FGD
11 blowdown. The Clean Water Act of 1972 (33 United States Code §1251 et seq.),
12 and the subsequent creation of the National Pollutant Discharge Elimination
13 System ("NPDES") permitting system, made wet ash handling and ash basins the
14 primary lawful and effective way to meet CCR needs and environmental
15 regulatory requirements from 1974 until 2015.

16 In June 2010, the United States Environmental Protection Agency ("EPA")
17 proposed national minimum criteria to regulate the disposal of CCR and the
18 operation and closure of active CCR landfills and existing and inactive CCR
19 surface impoundments. Approximately five years later, EPA published the final
20 CCR Rule in the Federal Register in April 2015.

21 In South Carolina, DE Carolinas entered into a Consent Agreement with
22 the South Carolina Department of Health and Environmental Control
23 ("SCDHEC") in September 2014. Pursuant to this agreement, DE Carolinas

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1 agreed to excavate its ash basins and ash storage areas at the W.S. Lee Steam
2 Station in Anderson County, South Carolina. It should be noted that other South
3 Carolina utilities are closing their ash basins in a similar fashion and also pursuant
4 to Consent Agreements with and approval from SCDHEC.

5 Also, in 2014, the state of North Carolina enacted the Coal Ash
6 Management Act of 2014 ("CAMA"), which requires that all ash basins in North
7 Carolina be closed, either through excavation or via the cap-in-place method. In
8 many respects, CAMA mirrors the federal CCR Rule.

9 All of DE Carolinas' ash basins must be closed under the CCR Rule,
10 South Carolina regulatory oversight, and/or CAMA. The Company has begun the
11 process of closing, or submitting plans to close, its ash basins in accordance with
12 the program with the most restrictive requirements. There is a great deal of
13 duplication and interaction between the CCR Rule and state regulatory
14 requirements. As I explain below in my testimony, many of the actions Duke
15 Energy will take will serve multiple compliance purposes. In fact, many actions
16 and draft rules applicable to many utilities, not just Duke Energy, were already
17 being developed prior to 2014, and we are now in another wave of evolution in
18 environmental regulation pertaining to ash. *See* Kerin Exhibit 2. In response to
19 these new requirements addressing CCR disposal activities, the Company is
20 adding dry fly ash, bottom ash, and FGD blowdown handling systems to
21 operating coal-fired plants that are not already so equipped. The Company is also
22 modifying all active and decommissioned plants to divert storm water and low-
23 volume wastewater away from the basins.

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1 Accordingly, the Company is requesting recovery of the incremental
2 compliance costs related to coal ash pond closures incurred starting January 2015
3 through ~~August~~ ^{September} 2018 and expected compliance costs from ~~September~~ ^{October} 2018
4 through December 2018 as explained in more detail by Company Witness Smith.
5 My testimony and exhibits demonstrate that both these incurred and expected
6 compliance costs are reasonable, prudent, and cost-effective given the individual
7 facts and circumstances at each power plant and ash basin site at issue.²

8 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

9 A. In this Section I, I have provided information concerning my background and the
10 purpose of my testimony. In Section II, I provide an overview of the generation
11 resources, including coal-fired generation, that the Company has used to reliably
12 and efficiently serve customers for over 100 years of its existence. I explain that
13 CCR are the natural byproduct of burning coal to generate electricity. I discuss
14 the Company's past practices for the storage and disposal of CCR, and I explain
15 that its practices have been in accordance with the electric power industry's
16 prudent standards and applicable laws, regulations, and permit requirements as
17 they have existed over time. In Section III, I discuss the new requirements
18 imposed on the Company under the new CCR compliance requirements. In
19 Section IV, I discuss the Company's plans to comply with the CCR compliance
20 requirements, the required regulatory approvals and permits for DE Carolinas'
21 compliance plans, including timing and implementation issues, and costs incurred
22 to date and expected over the next several years. I also explain and demonstrate

² This case excludes any fines or penalties incurred by DE Carolinas related to ash basin closure or management.