RECEIVED

SEP 21 2020

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 III OF XIII

Attorneys for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC

Heather Shirley Smith Deputy General Counsel Duke Energy Carolinas, LLC Duke Energy Progress, LLC 40 West Broad St., Suite 690 Greenville, SC 29601 heather.smith@duke-energy.com Thomas S. Mullikin Mullikin Law Firm 1308 Broad Street Camden, SC 29020 tommullikiin@mullikinlaw.com	Sarah P. Spruill Haynsworth Sinkler Boyd, P.A. ONE North Main Street, 2nd Floor Greenville, SC 29601 sspruill@hsblawfirm.com Frank R. Ellerbe, III Robert E. Stepp Robinson Gray Stepp & Laffitte, LLC P.O. Box 11449 Columbia, SC 29211 fellerbe@robinsongray.com rstepp@robinsongray.com

Attorneys for Respondents and Respondent/Appellant

Jeffery M. Nelson Jenny R. Pittman C. Lessie Hammonds Andrew M. Bateman Alexander W. Knowles Christopher M. Huber Office of Regulatory Staff 1401 Main Street, Suite 900 Columbia, SC 29201 jnelson@ors.sc.gov jpittman@ors.sc.gov lhammonds@ors.sc.gov abateman@ors.sc.gov chuber@ors.sc.gov aknowles@ors.sc.gov Wallace K. Lightsey Wyche, P.A. 200 East Camperdown Way Greenville, SC 29601-2972 wlightsey@wyche.com Attorneys for The South Carolina Office of Regulatory Staff	Richard L. Whitt Whitt Law Firm, LLC 401 Western Lane, Suite E Irmo, SC 29063 richard@rlwhitt.law Attorneys for Cypress Creek Renewables, LLC and S.C. Solar Business Alliance, Inc. Scott Elliott Elliott & Elliott, P.A. 1508 Lady Street Columbia, SC 29201 selliott@elliottlaw.us Attorneys for S.C. Energy Users Committee Hasala Dharmawardena 145 Cochran Road, Unit 4 Clemson, SC 29631 hasala@ieee.org *Pro Se*

L. Rebecca Dover
Carolyn Grube-Lybarker
SC Department of Consumer Affairs
P.O. Box 5757
Columbia, SC 29250
bdover@scconsumer.gov
clybarker@scconsumer.gov
Attorneys for SC Department of Consumer Affairs

Carrie H. Grundmann
Stephanie U. Eaton
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, NC 27103
cgrundmann@spilmanlaw.com
seaton@spilmanlaw.com
Derick P. Williamson
Spilman Thomas & Battle, PLLC
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, PA 17050
dwilliamson@spilmanlaw.com
Attorneys for Walmart, Inc.

Robert R. Smith, II
Moore & Van Allen, PLLC
100 North Tryon Street, Suite 4700
Charlotte, NC 28202
robsmith@mvalaw.com
Garrett A. Stone
Michael K. Lavanga
Stone Mattheis Xenopoulos & Brew, PC
8th Floor, West Tower
1025 Thomas Jefferson Street, NW
Washington, DC 20007-5201
gas@smxblaw.com
mkl@smxblaw.com
Attorneys for Nucor Steel-South Carolina

Alexander G. Shissias
The Shissias Law Firm, LLC
1727 Hampton Street
Columbia, SC 29201
alex@shissiaslawfirm.com
Attorneys for CMC Recycling

James Blanding Holman IV
Southern Environmental Law Center
Suite 200
525 East Bay Street
Charleston, SC 29403
bholman@selcsc.org
David L. Neal
Gudrun Elise Thompson
Southern Environmental Law Center
601 West Rosemary Street, Unit 220
Chapel Hill, NC 27516-2356
gthompson@selcnc.org
dneal@selcnc.org
Attorneys for S.C. Coastal Conservation League, Upstate Forever, and the South Carolina State Conference of the National Association for the Advancement of Colored People

Robert Guild
314 Pall Mall St.
Columbia, SC 29201
bguild@mindspring.com
Bridget M. Lee
50 F Street, NW, Floor 8
Washington, DC 20001
bridget.lee@sierraclub.org
Attorneys for the Sierra Club

Bess J. DuRant
Sowell & DuRant, LLC
1325 Park Street, Suite 100
Columbia, SC 29201
bdurant@sowelldurant.com
Thadeus B. Culley
1911 Ephesus Church Road
Chapel Hill, NC 27517
thad@votesolar.org
Attorneys for fVote Solar

INDEX

I. Public Service Commission Docket No. 2018-318-E (Duke Energy Progress, LLC)

Orders

Order No. 2019-341 dated May 21, 2019 1

Order No. 2019-454 dated October 18, 2019 118

Pleadings

DEP Application dated November 8, 2018 (without exhibits) 142

DEP Petition for Rehearing dated May 31, 2019 172

Transcript of Florence Night Hearing held April 1, 2019 188

Testimony

Hugh E. Weathers 198
Harry Ott 207
Anthony Ward 219
Kenneth Nance 228
Woody Timmons 234
Buquilla Cannon 238
Sarah A. Mellen 241
John Monroe 242
Richard Ervin 244
DuPree Atkinson 253
Ruthie Tarlton 260
Lillian L. Walker 265
Gill Rogers 270
Rutha Frieson 274
Terry James 277

Transcript of Testimony and Proceedings before the Public Service Commission 281

Testimony

Kodwo Ghartey-Tagoe and Laura Bateman 281
Janice Hager 590
David C. Parcell 596
Jon F. Kerin and Julius A. Wright 604
Robert Hevert and John L. Sullivan 817

Kevin W. O'Donnell 822
Michael L. Seaman-Huynh and Dan J. Wittliff 825
Kelvin L. Major and Zachary J. Payne 1044
Steven W. Hamm and Willie J. Morgan 1094

Exhibits

Ex. 14 (partial) 1200
Ex. 15 1222
Ex. 35 1231
Ex. 39 (partial) 1235
Ex. 42 1314
Ex. 59 (partial) 1327
Ex. 60 (partial) 2170
Ex. 61 2461
Ex. 67 2469
Ex. 71 2475

II. Public Service Commission Docket No. 2018-319-E(Duke Energy Carolinas, LLC)

Orders

Order No. 2008-417 dated June 9, 2008 3821

Order No. 2011-454 dated July 1, 2011 3859

Order No. 2019-323 dated May 21, 2019 3887

Order No. 2019-455 dated October 18, 2019 3958

Pleadings

DEC Application dated November 8, 2018 (without exhibits) 3979

SCEUC Petition to Intervene dated January 10, 2019 4009

PSC Directive granting SCEUC Petition to Intervene dated January 10, 2019 4015

SCEUC Amended Brief dated April 25, 2019 4016

DEC Petition for Rehearing dated May 31, 2019 4022

SCEUC Petition for Rehearing dated May 31, 2019 4036

Transcript of Spartanburg Night Hearing held March 12, 2019 4047

Testimony
Cynthia B. Knight 4047
Jeremy Boiter 4048

Transcript of Testimony and Proceedings before the Public Service Commission 4049

Testimony
Kodwo Ghartey-Tagoe and Kim H. Smith 4049
Christopher M. Fallon and Nils J. Diaz 4333
David L. Doss 4476
David C. Parcell 4478
John F. Kerin and Julius A. Wright 4484
Dan J. Wittliff 4742
Kevin W. O'Donnell 4859
Gaby Smith, Zachary J. Payne and Steven W. Hamm 4879
Robert B. Hevert 4996
Janice D. Hager 5002
Further Testimony of Kim H. Smith 5007
Willie J. Morgan, Michael L. Seaman-Huynh and John C. Ruoff 5070

Exhibits
Ex. 10 (partial) 5119
Ex. 17 5120
Ex. 19 5155
Ex. 29 (partial) 5159
Ex. 33 (partial) 5267
Ex. 34 (partial) 5592
Ex. 35 5994
Ex. 43 6005
Ex. 47 6016
Ex. 48 6022
Ex. 49 6053
Ex. 56 6059

subject to the additional costs from the legislature of another state, and that is not appropriate.

Q Okay. So, just to be clear, is the ORS position that, anytime North Carolina passes a law that affects DEP or DEC's cost of service, if there's an incremental impact above and beyond the costs that would otherwise have been incurred, South Carolina should not be asked to pay for any of those costs?

A (SEAMAN-HUYNH) Do you have any specific examples?

Q Well, we're talking about CAMA right now, and I'm just trying to understand whether the position you're taking with CAMA, which is a North Carolina law that imposes costs upon DEP beyond what would otherwise be required by federal law -- and if I'm understanding you correctly, you say South Carolina should not be asked to pay for any of those incremental costs; is that right? Did I accurately reflect your testimony?

A (SEAMAN-HUYNH) You did.

Q Okay. And I'm simply asking, for going-forward purposes, is that a -- a broad general principle that the ORS is going to apply or is it more of a case-by-case basis?

A (SEAMAN-HUYNH) I would say that it's a case-by-

case basis, but we do have past precedent from both North Carolina and South Carolina where jurisdictional costs have been allocated solely to -- within that jurisdiction.

Q So we'll -- we'll focus here upon just the CAMA cost that you believe should not be allocated at all to South Carolina because they're passed by North Carolina. And am I correct that South Carolina is not benefiting from those costs?

A (SEAMAN-HUYNH) I'm not sure what you mean by "benefiting," but I don't believe that I address that within my testimony.

Q Well, then, I'm confused, because we've established that the costs were prudently incurred and they're reasonable, so once you cross those two thresholds, the only reason I can see why the ORS would say we should -- we, the South Carolina portion of DEP's grid, should have to pay for any of those is if there's no benefit to South Carolina from DEP having incurred those costs. If -- if that's not the reason, what is the reason that South Carolina should not be allocated any of those CAMA costs?

A (SEAMAN-HUYNH) I believe I stated our position that South Carolinians should not have to pay for laws -- incremental differences passed by laws in

North Carolina where they do not have any say in the matter.

Q But what if the incremental cost is a -- produces a benefit for South Carolina?

A (SEAMAN-HUYNH) Are there any in this case? I know I'm not supposed to be asking you questions.

Q And I'm not going to answer. So -- but -- I'm completely befuddled, because you and I've been doing this a long time, and if a utility cost is just, is prudent, is reasonable, then it is -- the utility is entitled to recover them, and I'm searching for what is that other element that the ORS is relying upon to disallow these costs.

And what I'm hearing you say is simply because North Carolina passed a law that imposed these additional costs without any consideration of whether the incremental costs incurred benefited South Carolina or not. So help me understand, what is that -- what is the -- the foundation of the ORS saying, "No. These just and reasonable costs should not be allocated to South Carolina for recovery"?

MR. BATEMAN: Mr. Chairman, this question has been asked and answered.

CHAIRMAN RANDALL: Well, let's go ahead and

answer this one time, and then we'll get it --

MR. ANTHONY: Thank you, because I haven't --

CHAIRMAN RANDALL: -- we'll move on because I haven't --

MR. ANTHONY: -- heard -- heard an answer.

CHAIRMAN RANDALL: -- heard the answer yet.

A (SEAMAN-HUYNH) I -- I'm not sure what you're looking for, Mr. Anthony. I've stated ORS's position and why we feel that position is reasonable.

Q And would you just say one more time what that reason is?

A (SEAMAN-HUYNH) It is ORS's position that South Carolina ratepayers should not have to pay for the incremental difference between the North Carolina state law and the federal law when -- regarding coal ash management and disposal.

Q Because?

A (SEAMAN-HUYNH) Because South Carolinians do not have a vote for anyone within the North Carolina legislature.

Q Okay. Well, we're going to come back to some -- some benefits that we definitely need to discuss, because it's the -- you seem to be hanging your hat on the fact that -- or the allegation that South

Carolina did not have a vote. What is the state agency of South Carolina charged with representing the using and consuming public with regard to utility matters?

A (SEAMAN-HUYNH) That would be the South Carolina Public Service Commission.

Q No. Representing them, not making decisions.

A (SEAMAN-HUYNH) Pardon me. That would be the Office of Regulatory Staff.

Q Uh-huh. And the Office of Regulatory Staff is -- is empowered to intervene in other states' utilities commissions proceedings, are they not?

A (SEAMAN-HUYNH) Yes. We are.

Q And you've done that in the past?

A (SEAMAN-HUYNH) We have.

Q So -- and there's nothing to stop the ORS from engaging a lobbyist to participate in the legislative process in North Carolina, is there?

MS. EDWARDS: (To Mr. Bateman) Objection. We can't engage lobbyists.

MR. BATEMAN: Objection, Mr. Chairman. The ORS does -- cannot --

MS. EDWARDS: (To Mr. Bateman) -- engage lobbyists.

MR. BATEMAN: -- obtain -- engage lobbyists.

MS. EDWARDS: (To Mr. Bateman) A state agency cannot have a lobbyist.

Q Is there anything that prohibits the ORS from expressing its position to the North Carolina General Assembly?

A (SEAMAN-HUYNH) I can't speak to that.

Q Okay. So, to the extent in the North Carolina utilities rate case where they address the issue of allocating these CAMA costs to South Carolina, South Carolina could've participated in that proceeding, could it not?

A (SEAMAN-HUYNH) They could, but I believe, in the North Carolina proceeding, the North Carolina Commission allocated North Carolina's costs.

Q And they also held that -- the -- the portion that was not allocated to North Carolina should be allocated to South Carolina, though, didn't they?

A (SEAMAN-HUYNH) I can't speak to that other than to say that allocations are divided amongst various jurisdictions. North Carolina Commission did that.

Q Okay.

A (SEAMAN-HUYNH) They are responsible to allocating the costs to their consumers.

Q Okay. But, to the extent South Carolina was not represented in that utilities commission

proceeding, that falls on the ORS for not choosing to participate in that proceeding; isn't that right?

A (SEAMAN-HUYNH) Yes.

Q Okay. Now, these prudent and reasonable costs associated with CAMA compliance are associated with plants -- coal burning plants, some of which have been in service for decades -- 40 to 70 years, right?

A (SEAMAN-HUYNH) Yes.

Q And those coal burning plants have provided three separate benefits to South Carolina during their operating life, haven't they? Number one, the electricity?

A (SEAMAN-HUYNH) Yes.

Q Number two, by building those plants in North Carolina, South Carolina didn't have its air quality impacted, its water quality impacted, land cleared, ash ponds built and filled up? South Carolina avoided having any of that impact to its environment by the plants being located in North Carolina, did they not?

A (SEAMAN-HUYNH) There are plants in North Carolina that do have an effect on the water in the river and the streams in South Carolina, so I would

disagree with that statement.

Q Well, the environmental impact of building and operating a coal plant in North Carolina is much greater than the impact if it were located in South Carolina? I mean -- oh, I said that in reverse.

The environmental impact of a coal plant located in North Carolina is much less than the impact it would be if that same plant was located in South Carolina from an environmental impact to South Carolina?

MR. BATEMAN: Mr. Chairman, this was not only asked and answered a second ago, it's also well beyond the scope of what Mr. Seaman-Huynh testified to in this proceeding.

MR. ANTHONY: Mr. Seaman is the policy witness here and my purpose here is to show there's tremendous benefit that South Carolina has reaped for decades from these plants, and if he's not the right person to talk, they need to find a witness who can, because he's the policy witness on this issue.

CHAIRMAN RANDALL: Overruled. Continue.

THE EXAMINATION BY MR. ANTHONY CONTINUES.

A (SEAMAN-HUYNH) Can you please restate the question?

Q The fact that these coal plants that are subject to CAMA, whose costs you do not want allocated to South Carolina, the fact they were located in North Carolina, the environmental impact -- the vast majority of the environmental impact associated with building and operating a coal plant has been burdened on North Carolina, but South Carolina has been able to enjoy the electricity they produce, right?

A (SEAMAN-HUYNH) For the most part, yes.

Q Well, at the most part, they didn't get the ash ponds that we're now trying to -- having to remediate? South Carolina avoided having the ash ponds because they were located in North Carolina where the plants are?

A (SEAMAN-HUYNH) I would say yes to that.

Q And the third benefit is, by seeping out -- excuse me -- I'm sorry -- I've been seeping up for so long, it just comes out.

The third aspect of this for DEP and the benefit to South Carolina from these plants being located in North Carolina is CP&L, Progress Energy, DEP plans their system to serve both North Carolina and South Carolina in the aggregate, do they not?

A (SEAMAN-HUYNH) They do.

Q And, by having that larger footprint and more customers, they enjoy economies of scale and scope in just about every arena, whether it's dispatching plants or buying coal or arranging for freight. Isn't there a benefit to that?

A (SEAMAN-HUYNH) Yes.

Q And, so, if -- if DEP was forced to start separating its system because of the refusal of South Carolina to pay its fair share of the cost and start serving a North Carolina system and a South Carolina system, that would drive up the cost of providing service, wouldn't it?

A (SEAMAN-HUYNH) I can't speak to that. South -- excuse me -- DEC -- DEP's only plants in South Carolina are both -- are nuclear and natural-gas fired.

Q Yes. But, in order to build -- South Carolina is only about, what, 15 percent of DEP's entire system?

A (SEAMAN-HUYNH) Eleven to thirteen percent is the figure I'm familiar with.

Q All right. So if -- if DEP were to attempt to build just a South Carolina system rather than a system in the aggregate, it would lose the economies of scale and scope that come with

building a system that is designed to serve both North and South Carolina?

A (SEAMAN-HUYNH) It would, but we're not suggesting that.

Q But that's a benefit from having those plants in North Carolina and part of an overall system?

A (SEAMAN-HUYNH) Yes.

Q Okay.

MR. ANTHONY: Now, Mr. Chairman, I'm going to ask Mr. Seaman-Huynh a question that requires me to set up a hypothetical, and I got to run through a few preliminary matters to set the context, if you'll bear with me.

Q Mr. Seaman-Huynh, if you would imagine that Commissioners Howard and Hamilton own farm land out in Marlboro County, and they're side-by-side neighbors, and they farm, and one day, Commissioner Howard says to Commissioner Hamilton, "You know, we got these two pieces of land right beside each other" -- and I failed to mention, Commissioner Howard's land is only about a third of Commissioner Hamilton's size of his -- his lot, so his -- his farm land is only about a third as big as Commission Hamilton's.

But they get together and say, "You know, it'd

be a lot more efficient if we farmed our land together, and we bought equipment together and irrigation equipment together, and ran this thing together." We could enjoy some of those economies of scale and scope that I've mentioned a while ago, okay.

And they look around and go, "Well, we need a place to put trash and other debris, and there's no reason to have two of those. Why don't we just have one?"

And Commissioner Hamilton, being the magnanimous person that he is, says, "I got the perfect spot. You just bring all your stuff and I'll pull all my stuff, and we're going to put all this debris and waste over here in this -- in this big old trash pit we'll -- we'll dig."

And decades go by, and they put tires and creosote poles and egg cartons and used oil and everything else in the world into that trash pit. And, low and behold, one day, Commissioner Hamilton's wife actually visits the farm, and she says, "My goodness gracious, what a mess you've got back there. You've got to clean that up. You got to haul off all that waste and debris and used oil, and I want a nice garden bed planted out there."

And it costs poor old Commissioner Hamilton $10,000 to clean up that big old trash pit, and he goes to Commissioner Howard and says, "You know, neighbor, you've been benefiting from this for decades. How about ponying up half the cost of me having to clean that up?"

And Commissioner Howard says, "Not me. I didn't benefit from you having to clean up that spot and put your garden bed in to satisfy your wife. I ain't paying anything."

What's your reaction to that? Is Mr. -- is Commissioner Howard doing the right thing?

MR. BATEMAN: Mr. -- Mr. Chairman, I would object on this. I -- I appreciate the hypothetical, but there were so many facts, it was so convoluted, to be honest, it was difficult to follow exactly the different facets that are going on in the hypothetical.

CHAIRMAN RANDALL: Overruled. I -- I was following it pretty good. I want to hear the answer.

Q So which one of them was in the right, Commissioner Hamilton or Commissioner Howard, in who -- whether Howard should have to pay $5,000 towards that $10,000 remediation cost?

A (SEAMAN-HUYNH) That's an interesting hypothetical, Mr. Anthony, I have to say, and I hesitate to answer because I don't want to disadvantage either of the commissioners. I think that your hypothetical leaves a lot of factors out that are points in this case. I think it may be more appropriate to suggest that, instead of Commissioner Hamilton's, Commissioner Howard's, land -- farm land both being in Marlboro County, that one commissioner's land was in Marlboro County and the other commissioner's land was in a conjoining county, and that it's one county that says that you have to clean it up. A hypothetical of using Commissioner Hamilton's wife isn't -- isn't appropriate in this case, I don't think.

Q Well, let's use your hypothetical. Let's assume that they are right on the border, and -- and Commissioner -- their -- their lands adjoin right on the border between the two counties, and Commissioner Hamilton is in Marlboro -- and I don't -- I can't name a county right next. Is it Dillon? What's -- what's next to Marlboro?

COMMISSIONER HAMILTON: Robeson County, North Carolina.

Q -- Robeson over there. Same fact situation, except

instead of Commissioner Hamilton's wife laying down the law, it's Marlboro County laying down the law, and Commissioner Hamilton has to clean up that trash pit and return it to pristine condition, and he goes to Commissioner Howard and says, "How about $5,000 to help me pay for this?"

And he says, "No, no, no, no. That's your problem. You're stupid enough to have located in Marlboro County. I ain't paying."

Is that right? Is that a fair way to treat people?

A (SEAMAN-HUYNH) Mirroring your hypothetical compared to the situation that we're in right now, yes.

MR. ANTHONY: I don't have any other questions.

CHAIRMAN RANDALL: Thank you. Commissioners? Commissioner Howard.

EXAMINATION

BY COMMISSIONER HOWARD:

Q Mr. Seaman-Huynh, I have one question, and it's not a hypothetical. You're suggesting 25 percent of the revenue be allocated for the fixed cost basic facility charge, correct?

A (SEAMAN-HUYNH) For the residential, small general

service, and the small general service constant load classes, yes, Commissioner.

Q Let me give you my mindset. My mindset is you and Ms. Edwards and Mr. Bateman and all are sitting up in a conference room at ORS saying, "What are we going to do?" and you pulled 25 percent out of the air. How do you justify the number? Had you said 23 1/2 or something, I might've said, "That makes sense," but just -- just pull up 25 percent. Do you understand where I'm coming from?

A (SEAMAN-HUYNH) I do, Commissioner, and let me say that the starting position -- our starting position when looking at the -- the basic facilities charges, we have the advantage of having Duke Energy Progress and Duke Energy Carolinas having just completed rate cases in North Carolina. So one of the things that we did was take a look at all of the public testimony and the Commission orders within that North -- within those North Carolina dockets.

One of the -- Duke Energy Carolinas used the minimum system method for designing its basic facilities charges in North Carolina, and the North Carolina Public Staff took issue with the magnitude of the basic facilities charge for the residential

class in North Carolina. The Public Staff witness up there recommended using 25 percent of the additional revenue requirement go towards the basic facilities charge. We looked at the analysis of the North Carolina Staff.

We then -- with that in mind, we then looked at the revenue requirement for South Carolina ratepayers and allocated that down to the residential class, as well as all of the other classes. We looked at the -- at 25 percent. We looked at other percentages, as well, in line with the ORS recommended revenue requirement, and we settled on a 25 percent of the revenue requirement go towards the BFC for not just the residential class the way that North Carolina Public Staff recommended, but also for its small general class -- excuse me -- small general service class and the small general service constant load class. We looked at other percentages besides 25 percent, but 25 percent seems reasonable, and that is our recommendation.

COMMISSIONER HOWARD: Thank you. Thank you, Mr. Chairman. No more questions.

CHAIRMAN RANDALL: Thank you. Commissioner Belser?

COMMISSIONER BELSER: Thank you, Mr. Chairman.

EXAMINATION

BY COMMISSIONER BELSER:

Q Good afternoon --

A (SEAMAN-HUYNH) Good afternoon.

Q -- Mr. Seaman-Huynh. How are you today?

A (SEAMAN-HUYNH) Well, thank you.

Q I'm looking at your Surrebuttal Exhibit 5, MSH-5. It's the average monthly residential bill comparison? Is that how --

A (SEAMAN-HUYNH) Yes, Commissioner.

Q -- you -- has ORS calculated energy charges with regard to its recommendation on rates on the --

A (SEAMAN-HUYNH) We have not.

Q Okay. Then how did you come up with this comparison, if you haven't calculated energy charges?

A (SEAMAN-HUYNH) If you take a look at my Surrebuttal Exhibit MSH-1, in Column -- Column D shows the ORS proposed revenue increase for each -- percentage for each class, not including the EDIT rider. You'll see, for the residential class, that is a 7.33 percent increase. We took the currently approved typical residential bill, which on my

Exhibit -- Surrebuttal Exhibit MSH-5 is $122.49, and increased it by that 7.33 percent to come up with a base total. We then -- excuse me -- and that would correspond with the $131.46 on my Surrebuttal Exhibit MSH-5. The difference between the 131.46 and the 121.20 is the inclusion of the EDIT rider.

Q Did you check back -- run that back through to make sure that that covered the revenue requirement that y'all had calculated through ORS's adjustments?

A (SEAMAN-HUYNH) Yes, Commissioner. If you, again, take a look at my Exhibit MSH-1 -- excuse me -- Surrebuttal MSH-1, and looking at Column C, you can see that the revenue requirement for each class totals up at the bottom to $32,130,000, which is ORS's recommended revenue requirement in this case -- excuse me -- additional revenue requirement.

COMMISSIONER BELSER: Okay. Thank you very much.

WITNESS SEAMAN-HUYNH: Yes, ma'am.

CHAIRMAN RANDALL: Thank you. Commissioner Whitfield?

COMMISSIONER WHITFIELD: Thank you, Mr. Chairman.

EXAMINATION

BY COMMISSIONER WHITFIELD:

Q Got a couple of questions for each of you, and they're pretty basic, but I'm going to kind of go back and forth between the two of you. I guess -- Mr. Seaman-Huynh, I guess I'll start with you. You had an exchange with Commissioner Howard about the -- determining the 25 percent increase from the BFC. In your testimony -- and you've said it again here on the stand today -- you say that it's not really ORS -- I just want to be clear -- you say it's not really ORS's position; that's just what the Company agreed to. Is that --

A (SEAMAN-HUYNH) That's --

Q -- what -- is that what you're still stating? Am I understanding you right? In other words --

A (SEAMAN-HUYNH) Yes, Commissioner.

Q -- ORS isn't necessarily in agreement to it. You're -- you're just stating that's what -- what the Company has agreed to? I'm -- and I'm talking about the $11.78 for residential for basic facilities charge.

A (SEAMAN-HUYNH) Yes, Commissioner.

Q Okay. So -- so, as I asked the other witness, ORS is still not staking that out as their position?

A (SEAMAN-HUYNH) I think it is a good starting

position, Commissioner. That is the -- the basic facility charge using the methodology that I am recommending to this Commission, and it's also based off of ORS's revenue requirement. Should that revenue requirement change, should the Commission approve something different, then --

Q Uh-huh.

A (SEAMAN-HUYNH) -- what ORS has recommended to the Commission, then -- then we would -- we would look at the methodology that we had used and, if necessary, make an additional recommendation to the Commission.

Q Okay. That's -- I was hoping you would say something when you were hesitating there. I'll ask you like I asked the other witness: Do you have a number? Do you have another number? Does ORS have another number in mind? For BFC.

A (SEAMAN-HUYNH) No, Commissioner. We don't.

Q Okay. Hold that thought just a minute. I want to go to Mr. Wittliff just a minute.

Mr. Wittliff, this is just as basic as it gets. Can you turn to your chart, Table 5.4?

A (WITTLIFF) Yes, sir.

Q I'll give you a second to get there. You had it on the screen earlier.

A (WITTLIFF) Yes, sir.
Q If you could -- if you could, give me a location on -- on these plants. I know what's in South Carolina, but if you could, give me a general location of the North Carolina plants.
A (WITTLIFF) Asheville is in southeast North Carolina, just across -- it's -- it's -- it's about 12 miles inside the border from South Carolina. Let me -- I'll tell you what. I've got -- I've got a map.
Q I don't think so, but . . .
A (WITTLIFF) No, no. Give me a second here. I've got a -- I can -- I can actually describe it now that I have a map here in front of me. Asheville is at the -- at roughly the intersection of Interstate 40 and -- trying to see the --
Q 26?
A (WITTLIFF) Yeah. There you go, sir.
Q Tell you what, Mr. Wittliff. How about I -- I read -- there's one or two I'm unsure of, but let me read what I got, and then you -- you add to it, if you know.
A (WITTLIFF) Yes, sir.
Q Weatherspoon, is that fair to say Lumberton, North Carolina area?

A (WITTLIFF) That is, sir.
Q Sutton, is that fair to say Wilmington area?
A (WITTLIFF) Yes, sir.
Q Roxboro, is that fair to say a little north of Raleigh?
A (WITTLIFF) Yes, sir.
Q Mayo, up near the Virginia line and also north of Raleigh; is that fair?
A (WITTLIFF) It's -- it's about 10 miles north and east of Roxboro.
Q Okay. Cape Fear, Wilmington area?
A (WITTLIFF) Cape Fear is -- find it on my map here. Cape Fear is -- is south of Raleigh.
Q Okay. And Asheville, Asheville area. Help me out with the HF Lee.
A (WITTLIFF) HF Lee is --
Q That's the one in -- where there's a wide disparity. Help me out with that location of that one.
A (WITTLIFF) I'm trying to remember the town that it's close to, but it's north of Weatherspoon. Just trying to remember the town that it's near. I've got -- I've got that on some other places, but it's in that general area, north of Weatherspoon.
Q Okay. I think I've got a handle. And of course,

Robinson is in South Carolina?

A (WITTLIFF) Yes, sir.

Q Talk to me about the -- of course, there've been demonstrated here today large disputes between the amount requested and the amount that ORS proposes, right?

A (WITTLIFF) Yes, sir.

Q And this kind of boils down to the -- the dispute over CAMA and dispute over -- as was just demonstrated again in another exchange here by Mr. Anthony.

What I want to ask you goes back to, I guess, an exchange with Mr. Elliott a little earlier. If you -- once you start down this path, you're complying with federal CCR regs and you're complying with CAMA, and then you're complying with a consent order here in South Carolina with DHEC. Once you head down this path -- Mr. Elliott had a -- a -- something up on the screen that showed an astronomical number.

I guess my question is to you, since you're the environmental witness. Where does it end, the cost? Where in your mind -- Mr. Elliott put a staggering number up there, and that's -- I know that's not in -- in this case, but where -- for the

ratepayer, where does it end? And you -- as an environmental expert, I want to ask -- ask you that question. Are -- are you seeing those staggering billions of dollars that he put up there? Where do you think -- is there an end in sight?

A (WITTLIFF) Commissioner, in anticipation that this question might come up with regard to -- I'm presupposing that the DEQ decisions in North Carolina kind of drive -- drive this discussion. And we did some analysis just -- you know, not -- I wouldn't say it's exhaustive or extensive, and we took the lowest value that we had from known off-site disposal, and we applied that to the different plants involved. We also took the lowest value that we had for on-site landfilling, and it depends on what is an acceptable alternative of a -- let's even call it a "doable alternative" at each one of these facilities.

And, using those very conservative numbers, our assessment -- systemwide -- now, it's -- admittedly, it's a -- these -- these are big numbers to begin with -- but our estimate is that the cost could increase for -- with on-site landfilling be -- for the lowest cost that we had available, that would be somewhere in the ballpark

of a $2 million adder -- a $2 billion -- a $2 billion adder to the cost that we have currently being asked for.

Then -- I'm -- I'm sorry. The total project cost -- I -- I apologize -- for these six sites, just the six sites. And if we take that low value for off-site hauling of dollars per ton and we apply them to it, and we get somewhere close to $5 billion adder.

Now, those could double beyond that, even, if -- the unit cost that we used was $83.41 a ton, and that's based on WS Lee. If we use the Dan River cost per ton, that -- that number is $162.43 a ton, so you can see that, if those unit costs are closer to the 162 than they are the 83, then costs could conceivably come close to doubling even more.

So, when you ask me is there an end in sight, the -- the number that we have that's very conservative says the impacts of on -- off-site landfilling at each one of these six sites could cost the system another $5 billion.

A (SEAMAN-HUYNH) Commissioner, if I could add --

Q Yes.

A (SEAMAN-HUYNH) -- to that.

Q Please.

A (SEAMAN-HUYNH) You ask where it's going to end. It ends for the ratepayer where this Commission says that it ends.

Q Okay. And I was going to direct this to Mr. Wittliff, but either one of you. What do you think the -- I'm trying to not be speculative, but this is going to call for speculation -- what do you think the probability of the two of you or somebody from ORS sitting back here on the witness stand in a few years with another rate case with the Company asking for another large amount? Where does it end? That's -- that's where I -- what I'm trying to get to. Do -- and I was asking him because he's the environmental witness, but either one of you can answer. That's fine with me.

A (WITTLIFF) Okay. It depends on what they find as they go into these sites and they starting doing the -- the point being, these are very conservative estimates. They could go up from here. They could -- they could conceivably be on the two -- 2-billion-dollar adder, if they can do on-site landfilling everywhere. But -- but the point being, I don't think there is. If you have laws that change and you have to go do something to fix it later, that's -- that's always been sort of the

issue with environmental compliance. As the Company has pointed out, as the laws change, they've got to -- they've got to comply, so the question is, does North Carolina stop at this point or -- or are there more -- is there more coming? And I -- I'm not -- don't have my crystal ball at this point.

Q Well, I guess that's kind of where I was going. Does North Carolina CAMA -- CAMA laws, does that -- does that kind of, sort of, end it, if you will?

A (WITTLIFF) Well, I think Dr. Wright pointed out yesterday -- and I'm not trying to quote him; I'm just trying to paraphrase what I understood him to say -- is he said North Carolina has always been on the forefront of -- of environmental pristineness. He -- he talked about the Skylines Act, talked about the Clean Smokestack Act, talked about a whole -- the Clean Beaches Act. That's -- the State has had a very progressive attitude towards the environment. They've got a beautiful state, it's pretty, and they want to keep it that way. I can certainly understand their -- their motivation for -- for doing the things they think are necessary to do that. The question is, where does it stop? And, you know, I think that that's what

Dr. Wright was talking about is that it may not.
Q Well, would you agree that that puts this Commission in -- in quite a predicament? And I want to ask you one more question, Mr. Wittliff. I don't think -- there was some debate about whether Mr. Anthony could question you or not, but in his exchange with Mr. Seaman-Huynh, he talked about the benefits of South Carolina ratepayers for joint dispatch, fuel savings, and some of those things I guess he was referring to from the merger. If the ratepayers benefited from those things and benefited from generation for these decades and decades and decades, then don't you see that this Commission is in quite a predicament here? What -- what would you do, if you were sitting up here?
A (WITTLIFF) Well, I'm -- I'm not, and I mean --
Q True.
A (WITTLIFF) -- and, to be quite frank, I'm kind of glad I'm not, because the --
Q We've heard that before.
A (WITTLIFF) Sure. Sure you have, because what y'all have here is a really tough job. On the one hand, you've got to balance the needs of the community, and you've got to balance the needs of the Company to continue as a viable entity to make

sure that they're not being unnecessarily punished for doing what they feel is the right thing. Those are -- those are huge, huge responsibilities to carry out. The -- the question that I see that the Commission has in front of it is, is it the will of the Commission that there has to be some sort of working relationship between the Commissions in the two states? I mean, obviously, allocations are being made by -- by one for the other, and -- and, so it seems to me that this would be an issue where the Commission, once you make your decision here, that perhaps -- and I'm not trying to tell you what to do, because it ain't my job -- but, at the same time, I think it might be worth -- worth the trouble to -- to -- to get together and see if y'all can come to a meeting of the minds, because this could go on a while. I mean, environmental ways -- environmental rules have a way of ratcheting up and up and up. I've been in this business for -- since '81, and I've seen nothing but that, so it could go -- it could go even more ratcheting, so -- and the cost would go up. So the question is, at what point do the -- does this Commission say, "We've got to figure out a way to get at least a handle on this going forward"? And

I think that getting together with the North Carolina Commission and talking about your mutual areas of concern might be a really good first step. I don't know if y'all do that already?

Q We know them very well, but we're limited --

A (WITTLIFF) Okay. Sorry.

Q -- in -- in what we can discuss. And I guess what I want to ask you, your testimony is that this occurred over decades and decades and decades; we didn't get in this overnight, and you're saying we're not going to get out of it overnight?

A (WITTLIFF) Yes, sir.

COMMISSIONER WHITFIELD: Thank you. That's all I have, Mr. Chairman.

CHAIRMAN RANDALL: Thank you. Any other questions? Commissioner Ervin.

COMMISSIONER ERVIN: Thank you, Mr. Chairman.

EXAMINATION

BY COMMISSIONER ERVIN:

Q So, to hear your cost estimate there that you spoke of earlier, did you say 186 per ton? Is that -- were the --

A (WITTLIFF) The -- the high end?

Q Yes, sir.

A (WITTLIFF) The high end is $162.

Q 162?
A (WITTLIFF) Yes, sir.
Q Okay. Was that the most recent?
A (WITTLIFF) Yes, sir. These are numbers that -- that I had run based on -- on the costs that we saw.
Q Right. And does CAMA require excavation?
A (WITTLIFF) It -- it does for everything but the low-risk sites, and that would be, in this case, Mayo and Roxboro.
Q So the bulk of it's going to have to be excavated?
A (WITTLIFF) Yes, sir.
Q What percentage?
A (WITTLIFF) Let's see here. I'm not sure that I want to do math from the stand --
Q Well, that's all right.
A (WITTLIFF) -- like we talked. But --
Q That's all right.
A (WITTLIFF) But it's -- it's quite a bit. Quite a bit. It's -- it's well over half.
Q And excavation and transportation's more costly?
A (WITTLIFF) Yes, sir.
Q Much more costly?
A (WITTLIFF) If you're transporting it off-site to a landfill distant, in -- in some cases, the hauls

are -- let's see here. One is 60 miles; another's 70 miles, but there's several that are 140/150 miles each way.

Q And you haven't even factored in an inflation rate, have you?

A (WITTLIFF) No, sir.

Q Or cost of fuel?

A (WITTLIFF) No, sir. No. It's just basically a, you know --

Q Cost of labor? None of that's been added in?

A (WITTLIFF) No. It's all -- it's all included. But it's -- but it's not like I -- I escalated them up.

Q Right. And over what period of time?

A (WITTLIFF) Well, if you're hauling it off-site, it depends on whether you're hauling it off-site with a unit train, which is generally a hundred cars, a hundred tons per -- per car, that's 10,000 tons per train, or if you're hauling it by tractor-trailer, which is in the ballpark of 20 -- I think I used 22/23 tons of -- of material per -- per haul. This goes to Commissioner Whitfield's comment in the DEC case about, you know, how many trucks and -- and how does that work? It -- it -- it's a lot.

It's -- in fact, in one case, I just ran a

number on a million tons -- just a million tons, not -- not 56 million tons at the four DEC sites or 25 million tons at the two -- but 1 million tons, it'll generate -- on a 24/7 basis -- three truckloads going down the road every two hours. Now that's some "chainsaw math." That's -- a friend of mine uses that term; "chainsaw" meaning it's real rough. But I'm going to tell you, that's -- there's a lot of cities that do not want that coming down their streets.

Q That's 24 hours a day, seven days a week?

A (WITTLIFF) Twenty-four/seven.

Q And for how many years?

A (WITTLIFF) For 1 million tons?

Q Uh-huh.

A (WITTLIFF) That's -- that's roughly a -- boy, I got -- hold on a minute. I just -- I did the calculation; I might as well make use of it. Where did I put it? There we go. There we go. Right there.

So over three years -- over three years, it would take thirty -- 38 to 41 truckloads per day or about three truckloads every two hours, 24/7.

Q And that's just for a million tons?

A (WITTLIFF) Just for a million tons.

Q And we're talking about an aggregate of how many tons?
A (WITTLIFF) At -- at -- for the DEP plants, what I'm showing is 25 to 26 million, and at the DEC four sites, that would be 56 million.
Q Thank you, sir.
CHAIRMAN RANDALL: Thank you. Commissioners, any other questions? Any redirect?
MR. BATEMAN: Yes, Mr. Chairman. I'll -- I'll work to keep it brief. Mr. Chairman, if I could, I'd like to start off with a question from a Commissioner and an answer given by Mr. Wittliff.

REDIRECT EXAMINATION

BY MR. BATEMAN:
Q This is South Carolina Code Section 58-27-170. I wasn't sure -- Mr. Wittliff, can you read that -- what that says there? I can try to zoom in a little more if -- if I need to.
A (WITTLIFF) Do you want me to read it aloud?
Q Yes, sir. If you could.
A (WITTLIFF) "The Commission may hold joint hearings and issue joint or concurrent orders in conjunction or concurrence with any official board or commission of any state or of the United States.

The Office of Regulatory Staff may make joint investigations with any official board or commission of any state or of the United States."

Q Thank you, Mr. Wittliff. And I -- I do have a few questions in addition to asking you to read that.

Mr. Wittliff, was your role to evaluate the reasonableness of CAMA?

A (WITTLIFF) No.

Q How was your charge in North Carolina different than your charge in South Carolina?

A (WITTLIFF) In North Carolina, we were charged with determining the reasonableness and prudency of the actions taken by Duke up to the time that CAMA became law.

Q And how does that relate --

A (WITTLIFF) Oh, sorry.

Q -- to what you specifically did in South Carolina?

A (WITTLIFF) In South Carolina, the primary charge -- in fact, our primary mission from the very beginning was to determine quantitatively what were the marginal increases in costs brought by CAMA and subsequent amendments, above and beyond what the federal CCR rules require.

Q And is your calculation here reliable?

A (WITTLIFF) Yes, sir.

Q Why are you comfortable with your methodology performed in this -- this proceeding before the Commission today?

A (WITTLIFF) In this -- in this case, we had an additional year's worth of data. I've been looking at this for two years and believe that we were able to come to some reasoned conclusions about what the data told us. In -- in the North Carolina case, money was not the primary motivation. In fact, that -- that whole discourse there that was highlighted in the North Carolina transcript was relating to a question from a commissioner who basically wanted to know did we -- you know, instinctively, we were telling -- not instinctively, but we were telling subjectively there were differences, there were cost increases. If you change the options, it's going to cost more to do this compared to that, compared to this, compared to that. So as you got more complex with the -- with the solutions, they cost a great deal more. And we provided that qualitative analysis, but it wasn't our charge to develop hard numbers. We -- we -- we made a -- a run at it.

But the weighted averaging wasn't the problem; the problem was -- is that we were dealing with

budgetary estimates and did not have enough -- enough data to make what I felt was a -- a sound conclusion. And I don't think weight averaging is a questionable methodology in most parts. And all we were using it for was trying to figure out how much of the claimed costs were engineering and planning for sites that were not covered -- were doing construction during the period that we understood was going to be simultaneous engineering and planning across the system. And so we -- it was just our way of levelizing those costs, trying to figure out what's a good estimate or good calculation for that. Weight averaging is -- is an accepted methodology.

The reason that weighted averaging wouldn't work there is we just didn't have enough data points, and we weren't comparing apples to apples. We were having -- some sites only had one or two options, maybe -- maybe one only. Others -- there are only two -- one or two sites that had all four options for closure considered so you had an apples-to-apples basis for comparing.

Q So am I correct that this Exhibit 63, of which a portion of it is now shown on the ELMO, is not applicable in this situation?

A (WITTLIFF) I don't believe so.
Q Mr. Wittliff, did your personal opinions impact your objective analysis?
A (WITTLIFF) Not at all.
Q Does CCR require beneficiation?
A (WITTLIFF) No.
Q Then it would follow that there are no savings associated with beneficiation that are required under the CCR rule, correct?
A (WITTLIFF) That's correct.
Q Mr. Wittliff, what closure method does the CCR rule require for Cape Fear?
A (WITTLIFF) It doesn't.
Q And, Mr. Wittliff, how many people worked with you on this proceeding and the previous DEC proceeding?
A (WITTLIFF) I'm sorry. Can you be more specific?
Q Sure. How many people worked with you in GDS in reviewing the data provided by the Company in this proceeding and the DEC proceeding?
A (WITTLIFF) There were three, and one time we had four, looking at the data. It was a lot of data to look at.
Q Do you know about how -- how many pages of material you reviewed?
A (WITTLIFF) There was a lot. I've got to say that

I think you can see some of those documents over there. There were -- we probably looked at about 6 inches worth of a stack of papers if you were looking at an equivalent stack. I guess that's about 1500 pages, maybe more.

Q Okay. And to be clear, Mr. Wittliff, there's no evidence in this record to support the conclusory statements outlined in AIR 1-95?

A (WITTLIFF) Thank you.

Q This is -- I'm not sure -- I'm not sure if you can see that, Mr. Wittliff.

A (WITTLIFF) Okay. Is this the one we were talking about -- no. Please kind of zoom in on it. Can you?

Q I sure can.

A (WITTLIFF) Okay. This is -- this is the one where we're talking about the -- the different plants. Excuse me. Earlier, when this was presented, I got to admit, this was the first time I'd seen this, and -- and I believe that the testimony provided by Karen didn't include this. I can certainly understand why someone would say, "Well, we provided this in discovery. You should've -- should've seen this." But it wasn't presented with the testimony, and so that's what my statement is

based on. Not -- not that it was never provided, because, had I seen this, I'd probably have modified that somewhat, but that it wasn't provided with the testimony.

Q Okay. And, Mr. Seaman-Huynh, I've got just a few questions for you. Let's see.

I asked Dr. Ruoff earlier a question about the ratemaking being an art and a science. Would you agree with -- with me that it is both an art and a science?

A (SEAMAN-HUYNH) Absolutely.

Q Can ORS, as a state agency, employ lobbyists?

A (SEAMAN-HUYNH) Not to my knowledge, no.

Q Could ORS employ a lobbyist to lobby the North Carolina General Assembly?

A (SEAMAN-HUYNH) I don't believe so.

Q Is it administratively easier to return the tax savings via a volumetric charge? This relates to the BFC.

A (SEAMAN-HUYNH) Yes. And I feel that it's more appropriate.

Q And finally, Mr. Seaman-Huynh, is it reasonable for South Carolina customers to pay disposal costs required by the North Carolina General Assembly that exceed the costs imposed by federal law?

A (SEAMAN-HUYNH) No.
Q Thank you so much.
CHAIRMAN RANDALL: Thank you. Re-cross?
MR. BURNETT: Thank you, Mr. Chairman. Only a handful.

RECROSS-EXAMINATION

BY MR. BURNETT:
Q Mr. Wittliff, the couple of Commissioners asking you questions about the recent North Carolina DEQ or whatever you want to call that.
A (WITTLIFF) Yes, sir.
Q Were you also aware that the Company has announced that it will appeal that North Carolina DEQ?
A (WITTLIFF) Yes, sir.
Q And some of the testimony you gave responding to Commissioner questions today illustrate why it might even be, in fact, impossible to comply with some of the things that DEQ has asked the Company to do like rolling trucks 24/7 for three years just for a single ton; isn't that right?
A (WITTLIFF) A single million tons.
Q A single million tons, right?
A (WITTLIFF) Yes, sir. I can understand that.
Q And you would understand that, when I get done here and go back to Charlotte with my colleagues, we're

going to be working on developing arguments just like that for our appeal; isn't that right?

A (WITTLIFF) Well, since you -- I'm going to say yes.

Q Yeah. And if we're successful in appealing that order, it may not be worth the paper it is written on. Would you agree with that?

A (WITTLIFF) If you're successful, it -- the way that it read to me was a determination. I didn't see the word "order" in it, but I can understand why you might take it that way.

Q That's right. So it could come to pass, to Commissioner Whitfield's question, that this could be over as soon as that appeal's over; isn't that right?

A (WITTLIFF) It could.

Q Okay. Thank you.

MR. BURNETT: That's all I have.

CHAIRMAN RANDALL: Thank you. All right. I want to thank you gentlemen for your testimony, and you may step down and be excused.

WITNESS WITTLIFF: Oh, good. A break.

(Witnesses excused)

CHAIRMAN RANDALL: Okay. Let's go with the

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 1 of 28

SURREBUTTAL TESTIMONY AND EXHIBITS OF

KELVIN L. MAJOR

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-318-E

IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC

FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS AND

REQUEST FOR AN ACCOUNTING ORDER

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Kelvin L. Major. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina, 29201. I am employed by the State of South Carolina as an Audit Manager, in the Audit Department of the South Carolina Office of Regulatory Staff ("ORS").

Q. ARE YOU THE SAME KELVIN MAJOR WHO PRESENTED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes. I pre-filed direct testimony and eight (8) exhibits with the Public Service Commission of South Carolina ("Commission") on March 4, 2019.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to certain issues raised in the rebuttal testimonies of Duke Energy Progress, LLC. ("DEP" or "Company") witnesses Laura Bateman, Renee Metzler, Lesley Quick, and Retha Hunsicker. My surrebuttal will address the Company's rebuttal testimonies in regards to:

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 2 of 28

- ORS Adjustment #21 to Annualize Operation and Maintenance ("O&M") Non-Labor Cost,
- ORS Adjustment #22 to Normalize O&M Labor Expenses,
- ORS Adjustment #25 to Amortize Rate Case Costs,
- ORS Adjustment #28 to Adjust for Credit Card Fees,
- ORS Adjustment #29 to Adjust O&M for Executive Compensation,
- ORS Adjustment #30 to Adjust for Customer Connect Additional Expense and Deferral,
- ORS Adjustment #32 to Synchronize Interest Expense with End of Period Rate Base,
- ORS Adjustment #33 to Adjust 1/8 O&M for Accounting and Pro Forma Adjustments,
- ORS Adjustment #36 to Remove Certain Expenses,
- ORS Adjustment #40 Customer Growth Adjustment, and
- ORS Adjustment #41 to Adjust Revenue, Taxes and Customer Growth for the Proposed Increase.

My surrebuttal testimony also updates ORS adjustment amounts for ORS Adjustment #30 to Adjust for Customer Connect Additional Expense and Deferral, Adjustment #32 to Synchronize Interest Expense with End of Period Rate Base, and Adjustment #39 to Adjust for Nuclear Supplies and Materials.

Q. PLEASE DESCRIBE ORS'S RESPONSE TO THE COMPANY'S REBUTTAL TESTIMONIES IN REGARD TO CERTAIN ADJUSTMENTS.

A. ORS's responses to the adjustments are as follows:

Adjustment #21 - Annualize O&M non-labor expenses

Company witness Bateman states in her rebuttal testimony that annualizing the impacts of inflation to an end of test period level is based on actual known and measurable inflation metrics. Per S.C. Code Ann. Regs.103-823(A)(3), the Commission requires rate

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 3 of 28

applications to be based on a historic 12-month test period. Traditionally, the Commission allows adjustments to the Test Year to reflect known and measurable changes in the Company's operating experience. Adjustments for "inflation" are not known and measurable. Consistent with Commission Order Nos. 84-108 and 85-841 in which the Commission expressly rejected adjustments for inflation, ORS recommends the Commission reject recovery of these costs, which are based on projections and estimates, as it shifts the risks from the Company to the customers. Customer's rates should not be calculated based on projected costs that may never be incurred by the Company.

Adjustment #22 – Normalize O&M Labor Expenses

Based on the rebuttal testimony of Company witness Bateman, the Company agrees with ORS's adjustment to update the salary allocator for DEP for wages and salaries and related employee benefit costs to the same date as the O&M labor expense, July 1, 2018.

The Company does not agree with ORS's recommendation to remove 50% of the Company's long and short term incentive ("LTI" and "STI") program costs for the reasons discussed by Company witness Metzler. Company witness Metzler's rebuttal testimony primarily addresses the Company's position in regards to overall compensation philosophy, the compensation programs provided by DEP, why a competitive compensation package is important, and how eliminating any portion of incentive compensation would decrease employees' total compensation to less than competitive levels.

Company witness Metzler's rebuttal testimony discusses earnings per share ("EPS") and also mentions Total Shareholder Return ("TSR"). A general definition of TSR is the total return of a stock to an investor, or the capital gain plus dividends. Both EPS and TSR are metrics that involve the performance of a Company's stock. Company witness Metzler's

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 4 of 28

rebuttal testimony includes Table 1: Summary 2017 STI Plan. This table indicates the Executive Leadership Team's ("ELT") STI payouts are based on 50% EPS and all remaining Non-ELT employees' STI payouts are based on 30% EPS.

Company witness Metzler's rebuttal testimony fails to include the components of the Company's LTI plan where 70% of LTI awards are based 50% on EPS and 25% on TSR, for a total 52.5% of the LTI payouts directly tied to the Company's stock performance. In addition, 30% of the Company's LTI plan payouts are for Restricted Stock Units which are retention payouts of Company stock that are not tied to any performance related metrics. ORS determined that an average adjustment of 50% to total LTI and STI payouts was reasonable and appropriate in this docket. An adjustment of 50% to total LTI and STI plan payouts equitably allocates the costs between customers and shareholders. If employees are largely driven by stock performance rather than the service to customers, a balanced approach to equitably share those costs is important. ORS's recommendation does not require DEP to reduce the total compensation package provided to their employees, only that the costs of the LTI and STI plans be shared equally between customers and shareholders.

An increase in the Company's EPS and TSR, due to an increase in the Company's rates through a rate case, with no actual improved Company efficiency or operating performance, substantially influences the LTI and STI payouts made to employees. This removes the incentive for employees to achieve earnings goals through performance, customer satisfaction, efficiencies, and cost reduction measures. Shareholders are the primary benefactors of increased EPS and TSR, of which these incentives are directly based. It also shifts the risks from the Company to the customer if the Company is allowed recovery of 100% of its LTI and STI payouts.

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 5 of 28

In addition, the Commission has the authority to regulate the Company's management practices and decisions in regard to prudency but does not regulate the Company's management of EPS or TSR. Allowing regulated utilities the recovery of employee incentives based on stock performance, EPS or TSR, would limit the Commission's ability to determine the prudency of those incentives. The Company's request to allow cost recovery of employee incentives based on stock performance, EPS or TSR, would also be a vast departure from this Commission's previous decisions on this issue. In Order No. 2012-951, the Commission found that incentive compensation is an accepted and necessary component of a utility company's compensation package and that there are sound reasons for offering incentive compensation as part of a competitively reasonable compensation package. In that order, the Commission also found that recovery of 50% of this incentive compensation expense is just and reasonable.

ORS's adjustment to remove 50% of the LTI and STI program incentive costs is reasonable as it is an equitable allocation of the costs between the customers and the Company.

Adjustment #25 - Amortize Rate Case Costs

In rebuttal testimony, Company witness Bateman opposes ORS's recommendations to exclude a return on the deferred rate case expenses during the deferral period and exclude rate case expenses from rate base. ORS reaffirms its original positon to exclude a return on rate case expenses and exclude rate case expenses from rate base as the expenses are related to O&M and are not capital in nature. The Company does not currently have a Commission approved accounting order authorizing a deferral.

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 6 of 28

In addition, Company witness Bateman opposes ORS's recommendation to disallow certain rate case expenses due to the Company's lack of sufficient documentation to support the costs. ORS attempted on several occasions to obtain sufficient documentation from the Company. On December 12, 2018, ORS sent Audit Request #14 to the Company asking the Company to provide a summary listing of rate case expenses, copies of all invoices and proof of payment. *See* Confidential Surrebuttal Audit Exhibit KLM-9, page 1. On December 20, 2018, the Company responded to Audit Request #14 by providing a summary excel file, legal invoices excel file, an internal labor excel file, and various invoices for some of the legal expenses. Confidential Surrebuttal Audit Exhibit KLM-9, page 2 shows an example of the excel information provided for amounts billed to DEP without a supporting invoice. On January 3, 2019, ORS issued ORS Audit Request #28 to request copies of legal invoices for the legal expenses that were not supported by the Company, *See* Confidential Surrebuttal Audit Exhibit KLM-9, page 3. On January 9, 2019, the Company responded. *See* Confidential Surrebuttal Audit Exhibit KLM-9, page 4. On January 14, 2019, ORS issued ORS Audit Request #38 to request the Company provide additional detailed information to include billing rates, billed time, and a description of services. This audit request has been attached as Confidential Surrebuttal Audit Exhibit KLM-9, page 5. On January 21, 2019, the Company submitted an excel workbook including a column with a general description for the legal expenses, and timesheets which lacked any reference to the specific legal action, service performed, or person billed which are shown on Confidential Surrebuttal Audit Exhibit KLM-9, pages 6 and 7.

On February 22, 2019, Duke Energy Carolinas, LLC ("DEC") employee Kim H. Smith, along with Company witness Bateman, contacted ORS to discuss the level of detail

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 7 of 28

that was needed to provide sufficient support. The Company provided a small sample that contained some additional information, which they characterized as the best the Company could provide. ORS clarified that proper documentation for cost recovery would include itemized work performed, hourly rates, and a detailed accounting of the time spent for the work performed. This information should be provided to the Company from the vendor to support the expenses the Company is requesting to include as rate case expenses. ORS cannot verify the summary information created by the Company is accurate. Complete information is important to ensure that customers pay for only expenses related to the rate case. ORS recommends the Commission adopt ORS's adjustment to rate case expenses and reject any rate case expenses not properly supported by the Company..

Adjustment #28 - Adjust for Credit Card Fees

Company witness Quick, in her rebuttal testimony, opposes ORS's recommendation to exclude the Company's growth projections in the calculation of credit card fee expenses. ORS's position for rejecting inflation-based estimates applies to the ORS recommendation the Commission reject the 20% growth projections included by the Company in the calculation of credit card fees. Per S.C. Code Ann. Regs.103-823(A)(3), the Commission requires rate applications to be based on a historic 12-month test period. Traditionally, the Commission allows adjustments to the Test Year to reflect known and measurable changes in the Company's operating experience. Adjustments for growth projections are not known and measurable. Consistent with Commission Order Nos. 84-108 and 85-841 in which the Commission expressly rejected adjustments for inflation, ORS recommends the Commission reject recovery of these costs, which are based on projections and estimates, as it shifts the

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 8 of 28

risks from the Company to the customers. Customer's rates should not be calculated based on projected costs that may never be incurred by the Company.

Company witness Quick states that the Company experienced an average historic year over year growth rate of 13% in online payment transactions from 2014 to 2017. In addition, to support her findings, she states that the Company reviewed other utilities around the country implementing fee free credit card usage and found that the projected increase in credit card transactions cited by these utilities ranged from 5% to 30%. This further supports ORS's position as to the uncertainty of the Company's proposed growth projection.

On page eight of Company witness Quick's rebuttal testimony, she proposes the Commission approve a deferral to include the incremental credit card fees that ORS does not recommend be included in this adjustment. ORS recommends the Commission reject Company witness Quick's request to establish a deferral for the credit card fee expenses should the Commission not include the growth projections, as the credit card fees are not extraordinary in circumstance or magnitude, or in the customer's interest. See ORS witness Payne's surrebuttal testimony for discussion of deferrals.

Adjustment #29 - Adjust O&M for Executive Compensation

ORS recommends the Commission adopt the ORS adjustment to O&M for executive compensation. The Company's adjustment eliminates 50% of the compensation (base pay, LTI and STI) of the four DEP executives with the highest level of compensation. ORS does not remove 50% of the LTI and STI payments for these four executives in its adjustment since 50% of those payments were already removed in Adjustment #22 by ORS. ORS reaffirms its calculation of this adjustment.

Adjustment #30 - Adjust for Customer Connect Additional Expenses and Deferral

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 9 of 28

Upon review of Company witnesses Bateman's and Hunsicker's rebuttal testimony, ORS proposes an additional adjustment to O&M expenses for the Customer Connect Project to reflect the actual incurred level of expenses in 2018 of $923,000. This results in an adjustment to O&M of $763,000 as $160,000 of costs associated with Customer Connect were included in the test year expenses. Inclusion of this adjustment results in an additional adjustment to income taxes of ($190,000) for a total adjustment to income taxes of ($267,000) associated with Customer Connect.

ORS recommends the Commission reject Company witness Hunsicker's forecasted average O&M expense of $1.4 million. This amount includes forecasted costs of $550,000 for inflation and contingency. Per S.C. Code Ann. Regs.103-823(A)(3), the Commission requires rate applications to be based on a historic 12-month test period. Traditionally, the Commission allows adjustments to the Test Year to reflect known and measurable changes in the Company's operating experience. Adjustments for inflation and contingencies are not known and measurable. Consistent with Commission Order Nos. 84-108 and 85-841 in which the Commission expressly rejected adjustments for inflation, ORS recommends the Commission reject recovery of these costs, which are based on projections and estimates, as it shifts the risks from the Company to the customers. Customer's rates should not be calculated based on projected costs that may never be incurred by the Company.

Due to ORS's additional adjustment, ORS recommends cancellation of the accounting order (Order No. 2018-553) for deferred expenses related to Customer Connect on the date of the order issued by the Commission in this docket.

Adjustment #36 – Remove Certain Expenses

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 10 of 28

ORS recommended an adjustment to other O&M expense of ($875,000) and income taxes of $218,000 to disallow sponsorships, lobbying expenses, service awards, advertising and other miscellaneous items. These items are non-allowable and not necessary to provide electric service to customers. Subsequent to filing the application, the Company proposed an adjustment to other O&M expense of ($97,000) and income taxes of $24,000 to remove lobbying costs and image building advertising.

Based on the rebuttal testimonies of Company witnesses Bateman and Metzler, the Company disagrees with ORS removing items associated with employee incentives, any costs to recognize and reward Company employees, lineman's rodeo costs, organization dues, costs that are not related to South Carolina ("SC"), timing differences and litigation expenses as part of its non-allowable adjustment.

ORS performed its non-allowable review of the Company's accounting records over a three (3) month period, concluded its initial review, and sent its list of non-allowable transactions to the Company on January 28, 2019. ORS requested the Company provide additional supporting documentation and detailed reasoning for why expenses should be allowed and included for recovery from customers. On February 11, 2019, ORS contacted the Company to inquire if the Company's response was forthcoming related to the transactions deemed non-allowable by ORS. On that same day, ORS received a response from the Company which indicated the Company reviewed the ORS spreadsheet containing the list of non-allowables. The Company's response identified certain transactions the Company intended to remove in the updated supplemental filing which included a new pro forma adjustment called "Remove Certain Expenses." The Company's response also identified instances where ORS duplicated removal of the same transaction and instances

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 11 of 28

where ORS recommended removing North Carolina ("NC") specific costs, like Department of Motor Vehicle ("DMV") costs, which were allocated between NC and SC. The Company indicated ORS's adjustment to non-allowables did not identify the comparable SC specific costs that were also allocated between NC and SC.

The Company indicated in its response all remaining transactions identified by ORS in the spreadsheet were reasonable expenses attributed to: prudent utility operations; community engagement; and maintenance of an engaged workforce. ORS requested the Company identify all transactions that were removed more than once, and on February 22, 2019, ORS received the Company's response. ORS modified its non-allowable adjustment to remove duplicate items. The Company provided no additional supporting documentation for specific non-allowable transactions.

Company witness Metzler, in her rebuttal testimony, specifically addresses ORS's non-allowable adjustment in regard to spot bonuses (exceptional contribution awards), lump sum merit payments, service awards, safety awards, lineman's rodeo, and miscellaneous costs to recognize and reward the Company's employees such as: a team lunch, decorations for an office celebration, and coffee supplies in the office. ORS recommended an adjustment to remove amounts associated with spot bonuses, service awards and safety awards, team lunch, coffee supplies in the office, and decorations for an office celebration consistent with Commission Order Nos. 89-573, 91-595, and 94-1229. In these Commission Orders, the Commission removed costs associated with sales incentive awards, safety and length of service awards, other miscellaneous gifts and awards, and parties. ORS removed costs associated with the lineman's rodeo as costs associated with competitions between linemen from various utilities are not necessary to provide quality electric utility service to customers.

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 12 of 28

DEP's customers should not have to pay costs not associated with providing quality electric utility service. ORS's treatment of rodeo related expenses in this docket is consistent with ORS's treatment of rodeo related expenses in other SC gas and electric utility rate cases and Rate Stabilization Act filings. The Company is incorrect in its statement that ORS's non-allowable adjustment removed amounts associated with lump sum merit payments made by the Company.

Company witness Bateman, in her rebuttal testimony, specifically addresses organization dues, costs that are not related to SC, timing differences due to accrual accounting, and litigation expenses. Company witness Bateman specifically identifies the Company's request to recover from its customers membership dues for local Chambers of Commerce, the Historic Marion Revitalization Association, and the Darlington Downtown Revitalization Association. ORS removed 50% of the dues associated with Chambers of Commerce as part of its non-allowable adjustment consistent with Commission Order Nos. 94-1229, 01-887, and 02-285 where the Commission found that one-half of dues paid to state and local Chambers of Commerce should be included in cost of service. In regards to the transactions associated with the Historic Marion Revitalization Association and the Darlington Downtown Revitalization Association, ORS removed amounts associated with these transactions based on the Company's designation of them as being related to "Memberships in Social and Athletic Clubs (including but not limited to Chamber of Commerce, Rotary, Lions, etc.)." Removal of costs for transactions associated with memberships in social and athletic clubs is consistent with Commission Order Nos. 91-595 and 94-1229.

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 13 of 28

The Company asserts that ORS included in its adjustment for non-allowables transactions related to costs that are not related to SC and timing differences for accrual accounting. ORS provided the Company ample opportunity to identify and provide additional supporting documentation for any transactions for which they did not agree with ORS's treatment as non-allowable. The Company failed to specifically identify transactions included in ORS's non-allowable adjustment related to these items during the non-allowable review process. In fact, despite ORS's request for information from the Company, ORS did not become aware of the Company's treatment of DMV registration fees for transmission vehicles until reading DEC employee Kim H. Smith's rebuttal testimony in Docket No. 2018-319-E. The same is also true for transactions included in ORS's non-allowable adjustment related to expenses incurred and accrued in a previous period but not paid until the test year. Had the Company properly supported these transactions with the explanations in Company witness Bateman's testimony when ORS originally asked for support, ORS would have had the opportunity to closely review and verify these transactions, determine the appropriate treatment, and modify its non-allowable adjustment appropriately. As a result of the Company's actions, ORS has not verified Company's witness Bateman's claims and ORS recommends the Commission reject the Company's position.

ORS's removal of litigation expenses as part of its non-allowable adjustment is discussed in detail by ORS witness Hamm's surrebuttal testimony.

Adjustments #33 - Adjust for 1/8 O&M for Accounting and Pro Forma Adjustments, Adjustment #40 - Customer Growth, and Adjustment #41 - Adjust Revenue, Taxes and Customer Growth for the Proposed Increase

ORS and the Company agree on the methodology used in calculating these adjustments. ORS and Company amounts differ due to the underlying adjustments of ORS and the Company and the recommended return on equity.

Q. DID ORS UPDATE ANY OTHER ADJUSTMENTS AS PART OF SURREBUTTAL TESTIMONY?

A. Yes. ORS updated ORS Adjustment #32 to Synchronize Interest Expense with End of Period Rate Base due to an increase in the weighted average cost of debt rate to 4.16% from 4.06% as accepted by ORS witness Parcell in his surrebuttal testimony. ORS also updated ORS Adjustment #39 to Adjust Nuclear Materials and Supplies based on the recommendation of ORS witness Morgan in his surrebuttal testimony.

Q. PLEASE IDENTIFY ADDITIONAL EXHIBITS ATTACHED TO YOUR SURREBUTTAL TESTIMONY.

A. I have attached the following exhibits to my surrebuttal testimony to reflect the update to ORS Adjustment #30 for the Customer Connect Project, the increase in the weighted average cost of debt rate to 4.16% from 4.06%, the update to Adjustment #39 for Nuclear Materials and Supplies, and the resulting changes to fall out adjustments:

- Surrebuttal Audit Exhibit KLM-1: Operating Experience, Rate Base and Rate of Return Reflecting ORS's Proposed Increase
- Surrebuttal Audit Exhibit KLM-2: Explanation of Accounting and Pro Forma Adjustments - Retail
- Surrebuttal Audit Exhibit KLM-3: Electric Plant in Service at Original Cost
- Surrebuttal Audit Exhibit KLM-4: Accumulated Depreciation and Amortization – Electric Plant in Service

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 14 of 28

- Surrebuttal Audit Exhibit KLM-5: Materials and Supplies
- Surrebuttal Audit Exhibit KLM-6: Working Capital Investment
- Surrebuttal Audit Exhibit KLM-7: Weighted Cost of Capital
- Surrebuttal Audit Exhibit KLM-8: Operating Experience, Rate Base and Rate of Return Reflecting the Company's Proposed Increase
- Confidential Surrebuttal Audit Exhibit KLM-9: Company responses to ORS Audit Request #14, #28, and #38

Q. WILL YOU UPDATE YOUR SURREBUTTAL TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental surrebuttal testimony should new information not previously provided by the Company, or other sources, become available

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 15 of 28

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 1 of 16

DIRECT TESTIMONY OF

ZACHARY J. PAYNE

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-318-E

IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS AND REQUEST FOR AN ACCOUNTING ORDER

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Zachary J. Payne. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina, 29201. I am employed by the South Carolina Office of Regulatory Staff ("ORS") in the Audit Department as a Senior Auditor.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND YOUR BUSINESS EXPERIENCE.

A. I received a Bachelor of Science Degree in Business Administration with a double major in Accounting and Economics from the University of South Carolina in May 2013. I began employment with ORS in March 2015 and since have worked on cases dealing with the regulation of nuclear waste, natural gas, water and wastewater companies.

Q. WHAT IS THE MISSION OF THE OFFICE OF REGULATORY STAFF?

A. ORS represents the public interest as defined by the South Carolina General Assembly as:

> The concerns of the using and consuming public with respect to public utility services, regardless of the class of customer, and preservation of

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 2 of 16

continued investment in and maintenance of utility facilities so as to provide reliable and high-quality utility services.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to set forth ORS's findings and recommendations for certain adjustments resulting from ORS's examination of the application of Duke Energy Progress, LLC ("Company" or "DEP"), in Docket No. 2018-318-E. Specifically I will be addressing ORS's findings and recommendations for Company Adjustments 17, 18, 19, 30, and 35, all of which are related to accounting deferrals. These findings and recommendations are explained in detail in my testimony.

Q. PLEASE OUTLINE THE FUNCTION OF AN ACCOUNTING ORDER TO DEFER COSTS.

A. An accounting order to defer costs is a regulatory instrument in which the regulatory commission issues an order at the utility's request to establish a regulatory asset (or liability) account into which certain costs can be deferred.* The Governmental Accounting Standards Board's (GASB) statement No. 62 provides, among other things, general standards of accounting for the effects of regulation and states that:

> A regulated business-type activity should capitalize all or part of an incurred cost that otherwise would be charged to expense if both of the following criteria are met:
>
> a. It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.
>
> b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs.

In other words, GASB identifies the key criteria the utility must meet to capitalize costs through an approved regulatory asset as:*

*Please see errata submitted 4/9/2019 attached hereto.

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 3 of 16

1) the incurred costs are likely to be recoverable for ratemaking purposes; and,

2) the costs have already been incurred, and the costs are not similar to costs the utility may incur in the future.

GASB statement No. 62 also indicates the utility should accrue "carrying charges" on the regulatory asset:

> During the period between the date on which the new asset is recognized and the date on which recovery begins, the carrying amount should be increased by accruing a carrying charge.

FASB GASB outlines the accounting standards for deferring costs; however, it is ultimately the regulatory commission that determines what costs in the regulatory asset are allowable for ratemaking purposes, and the manner in which the utility is allowed to recover the allowable costs in the regulatory asset.

Once an accounting order is issued by the regulatory commission, the utility will create a regulatory asset account on its balance sheet and record costs to the regulatory asset as the costs are incurred. The utility will request to recover regulatory assets in a future general rate case proceeding. It is during the general rate case proceeding the regulatory commission will determine the appropriate amount of allowable costs to be recovered from customers, and the manner in which the utility is allowed to recover allowable costs. Accounting orders are used by a utility to smooth earnings and rate recovery related to significant costs that arise from circumstances that are unexpected and/or non-recurring.

Q. WILL ORS REQUEST THE COMMISSION CONSIDER GUIDELINES FOR FUTURE DEFERRAL REQUESTS?

A. Yes. In Docket No. 2018-206-E, Duke Energy Carolinas, LLC, DEP, (collectively "the Companies") and ORS discussed the Companies' request for approval of an accounting

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 4 of 16

order to defer certain capital and operating expenses pursuant to S.C. Code Ann. § 58-27-1540 and S.C. Code Regs. 103-825 related to the Power/Forward Initiative. On September 4, 2018, ORS filed a letter in the docket to inform the Commission that ORS would make a future filing in 2019 to request a proceeding to adopt guidelines on future deferral requests. In Commission Order No. 2018-751, the Commission adopted ORS's proposed conditions on this matter. ORS intends to make such a filing no later than December 2019.[1]

Q. PLEASE SUMMARIZE ORS'S RECOMMENDATIONS FOR THE TREATMENT OF ACCOUNTING DEFERRALS PROPOSED BY THE COMPANY.

A. ORS reviewed each of the Company's proposals for recovery of accounting deferrals and has developed a recommendation to be applied to the requests by the Company to recover its deferred costs. In most of the Company's deferrals the Company calculated a weighted average cost of capital ("WACC") return on deferred costs. Additionally, the Company proposed to include the unamortized balance of most of the deferrals in rate base. ORS recommends each deferral balance be separated into two categories of costs: operating-related costs and capital related costs. ORS recommends the recovery of both the operating-related costs and the capital-related costs be subject to the same regulatory accounting treatment required for each category absent an accounting deferral. According to the National Association of Regulatory Utility Commissioners ("NARUC") Rate Case and Audit Manual, regulatory assets and other deferrals should be examined to determine if the deferred costs are appropriate to be included in rate base. The Company may recover prudently incurred operating expenses, without a WACC return or rate base treatment. The Company may recover prudently incurred capital costs by recording capital costs to rate base and recovering

[1] https://dms.psc.sc.gov/Attachments/Matter/36a3a7be-111b-4103-8131-bd54da3ec5de

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 5 of 16

those costs through depreciation expense over the life of the associated asset, while earning a WACC return on the undepreciated balance. With the exception of deferred environmental costs in Adjustment #18, which is discussed later in my testimony, the ORS recommendations allow the Company to fully recover its actual deferred expenses. ORS's recommendations focus on how those costs should be recovered. ORS's recommendations are in the public interest because the recommendations allow for a return of costs and, where it is appropriate, a return on costs.

Q. PLEASE EXPLAIN ORS'S RECOMMENDED ADJUSTMENTS.

A. Explanations of the accounting and pro forma adjustments are presented on a South Carolina retail basis for both ORS and the Company. As shown on Audit Exhibit KLM-2, the ORS adjustment numbers are the same as those filed by the Company in its Application. My recommended adjustments for accounting deferrals are as follows:

Adjustment #17 – Adjust For Previously Deferred Amounts – Harris COLA, Fukushima/Cybersecurity, 2014 Storms, and GridSouth

The Company proposes to adjust depreciation and amortization expense by $3,184,000, income taxes by ($794,000), working capital investment by ($15,754,000), and accumulated deferred taxes by $3,931,000 to amortize previously deferred costs related to Harris COLA, Fukushima/Cybersecurity, 2014 Storms, and GridSouth. ORS proposes to adjust depreciation and amortization expense by $2,634,000, income taxes by ($657,000), working capital investment by ($23,118,000), and accumulated deferred taxes by $5,768,000 to amortize previously deferred costs related to Harris COLA, Fukushima/Cybersecurity, 2014 Storms, and GridSouth. Each deferral is discussed in detail below.

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 6 of 16

Harris COLA Deferral - Commission Order No. 2014-138 granted the Company's request for an accounting order to defer "certain costs incurred in connection with the development of proposed Units 2 and 3 of the Shearon Harris Nuclear Station." The Commission order also stated "(g)ranting the deferrals will not preclude this commission or any party from addressing the reasonableness of the costs deferred in regulatory asset and liability accounts in the next general rate proceeding." The Company provided ORS with support for a Harris COLA deferral balance of $6,715,000. The Company proposes amortizing the deferral balance over a five year period. The Company has not proposed to include the unamortized deferral balance in rate base.

ORS agrees with the deferral balance of $6,715,000, and proposal to exclude the unamortized deferral balance from rate base. However, ORS disagrees with the Company's proposal to amortize the deferral balance over a five year period. ORS recommends the deferral balance be amortized over an eight year period. ORS's recommendation to amortize the deferral balance over an eight year period is reasonable because it matches the time period the Company incurred and deferred the costs which was from 2006 to 2013.

Fukushima/Cybersecurity Deferral - Commission Order No. 2014-138 also granted the Company's request for an accounting order to defer "the incremental Operating & Maintenance (O&M) expenses that will be incurred as a result of complying with existing and future requirements promulgated by the Nuclear Regulatory Commission ("NRC") in response to the events at the Fukushima Daiichi Nuclear Power Station in Japan and the incremental O&M expenses that will be incurred to comply with cybersecurity regulations mandated by the NRC." The Commission order also stated "(g)ranting the deferrals will not preclude this commission or any party from addressing the reasonableness of the costs

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 7 of 16

deferred in regulatory asset and liability accounts in the next general rate proceeding." The Company provided ORS with support for a Fukushima/Cybersecurity deferral balance of $5,541,000, consisting of a December 31, 2017 balance of $4,729,000, actual costs to defer during the 2018 year of $324,000, projected costs to defer between January 1, 2019 to May 30, 2019 of $242,000, and a 2018 correction to the 2017 balance of $246,000. The Company proposes to amortize the deferral balance over a five year period. The Company's application per book rate base includes the $4,729,000 December 31, 2017 deferral balance. The Company proposes to include the additional deferred amounts, less one full year of amortization in rate base.

ORS proposes a Fukushima/Cybersecurity deferral balance of $5,299,000 which will provide the Company a recovery of actual deferred costs as of December 31, 2018 including the 2018 correction to the 2017 balance. ORS recommends the Commission approve the five year amortization period for the deferral balance proposed by the Company. ORS does not recommend the deferral balance include projected costs because projected costs are not known and measurable. ORS recommends the December 31, 2017 deferral balance be removed from the Company's rate base since the balance consists of deferred O&M expense. Likewise, ORS recommends the remaining deferral balance be excluded from rate base because it consists of deferred O&M expense. ORS's recommendation to remove and exclude the actual deferred O&M expense from rate base is consistent with regulatory accounting practices for operating-related costs. ORS's recommendation allows the Company to recover its actual deferred costs through amortization of the proposed deferral balance which is a sufficient level of cost recovery. If the Company is allowed to include deferred O&M expenses in rate base, the Company will earn a return on its O&M expenses.

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 8 of 16

GridSouth Deferral – On April 12, 2001 DEP (formerly Carolina Power & Light Company) was party to a joint application filed with the Commission for authority to transfer functional control of transmission assets to GridSouth Transco, LLC under Docket No. 2001-139-E. On February 19, 2002, the joint applicants filed a notice of withdrawal of the application. The Company incurred costs totaling $3,676,000, which it deferred to an account in its rate base, as a result of the initial application. The Company proposes to recover these costs by amortizing this deferral balance over a five year period.

ORS agrees with the proposed deferral balance of $3,676,000, and the Company's proposed five year amortization period. ORS recommends removing the deferral balance from the Company's rate base as the costs are not capital expenditures. ORS's recommendation to remove the deferred expenses from rate base is consistent with regulatory accounting practices for operating-related costs. ORS's recommendation allows the Company to recover its actual deferred costs through amortization of the proposed deferral balance which is a sufficient level of cost recovery. If the Company is allowed to include deferred non-capital expenses in rate base, the Company will earn a return on non-capital expenses in excess of what it has already earned since its last general rate case.

2014 Storm Costs Deferral – Commission Order No. 2015-62 granted the Company's request "for an Accounting Order to Defer Storm Damage Expenses incurred as a result of snow and ice storms in 2014. The Company incurred $14.8 million in incremental operating and maintenance expenses to repair and restore its South Carolina system." The Company has since carried the deferral balance in a regulatory asset account as part of its rate base. As stated in Company witness Laura Bateman's testimony, "(t)his adjustment removes the South Carolina retail deferred balance from rate base. The Company is instead requesting to

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 9 of 16

accrue a return on the deferred balance while it explores alternative cost recovery options for the significant storm costs incurred by the Company over the last five years."

ORS agrees with the Company's proposed treatment to remove the deferral balance from rate base. ORS also agrees with the Company's proposal to accrue a return on the balance as GASB Statement 62 directs regulated businesses such as the Company to accrue a carrying charge on deferred cost regulatory assets from the time the assets are created until recovery of the asset begins. ORS reserves its rights to address the reasonableness of the costs deferred in the regulatory asset account in the next general rate proceeding.

Adjustment #18 – Amortize Deferred Environmental Costs

The Company proposes to adjust depreciation and amortization expense by $10,080,000, income taxes by ($2,515,000), working capital investment by $40,322,000, and accumulated deferred taxes by ($10,060,000) to amortize the deferred environmental costs. ORS proposes to adjust depreciation and amortization expense by $879,000, income taxes by ($219,000), working capital investment by $3,288,000, and accumulated deferred taxes by ($820,000) to amortize the deferred environmental costs.

Commission Order No. 2016-490 granted the Company's request "for an accounting order authorizing the deferment of certain costs incurred in connection with complying with federal and state environmental remediation requirements related to permanently closing coal ash basins and other ash storage units at the Companies' coal fired generating facilities." The Commission order also stated "This ruling in no way limits the ability to challenge the reasonableness of these expenditures in a subsequent general rate case or other proceeding." The Company provided ORS with support for a deferral balance of $50,402,000 consisting of $50,740,000 in deferred asset retirement obligation ("ARO") plant spend, ($5,062,000) in

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 10 of 16

offsets from the nuclear decommissioning trust fund ("NDTF") overcollection and retired and active plant cost of removal collections, $5,150,000 in after-tax WACC return on the ARO plant balance, ($1,517,000) for an Ashville prudence disallowance, $764,000 for a WACC return on the non-ARO plant balance, $307,000 for deferred depreciation of the non-ARO plant balance, and $20,000 for an after-tax return on the deferred non-ARO costs. The Company proposes amortizing this deferral balance over a five year period, and including the balance less one year of amortization in rate base.

ORS proposes a deferral balance of $4,394,000 which includes $9,726,000 in deferred ARO plant spend, ($5,062,000) in in offsets from the NDTF overcollection and retired and active plant cost of removal collections, $466,000 in after-tax WACC return on the ARO plant balance, ($1,517,000) for an Ashville prudence disallowance, $553,000 for a WACC return on the non-ARO plant balance, and $227,000 for deferred depreciation of the non-ARO plant balance. ORS proposes including in rate base all components of the deferral balance (less one year of amortization) except for the deferred depreciation of the non-ARO plant balance. ORS's recommendation to include the deferred capital costs portion of the deferral in rate base, and exclude the deferred depreciation expense from rate base is consistent with regulatory accounting practices for capital-related and operating-related costs.

ORS calculated its proposed deferral balance starting with the disallowed ARO system expenditure through September 30, 2018 provided in the testimony of ORS witness Dan Wittliff. The ORS Audit Department calculated an allowable percentage per month based on Mr. Wittliff's recommended total amount and applied that percentage to the ARO monthly expenditures that were originally provided by the Company. Creating an allowable

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 11 of 16

monthly expense allocation was necessary to calculate the WACC return in a manner consistent with the Company's original calculation. ORS then added the non-ARO WACC return and deferred depreciation expense to the allowable ARO plant spend, less NDTF overcollection, plus WACC return on the allowable plant balance. ORS does not recommend the Commission adopt the Company's calculation of a WACC return on the non-ARO deferred cost of capital and deferred depreciation expense. ORS did not include such a return in the proposed deferral balance. If the Company is allowed to include depreciation expense in rate base, the Company will earn a return on these expenses.

Adjustment #19 – Amortize Deferred Cost Balance Related to South Carolina Advanced Metering Infrastructure ("SC AMI")

The Company proposes to adjust depreciation and amortization expense by $468,000, income taxes by ($117,000), working capital investment by $935,000, and accumulated deferred taxes by ($233,000) to amortize the deferred cost balance related to SC AMI. ORS proposes to adjust depreciation and amortization expense by $104,000, income taxes by ($26,000), working capital investment by $861,000, and accumulated deferred taxes by ($215,000) to amortize the deferred cost balance related to SC AMI.

Commission Order No. 2018-553 granted the Company's request "to defer (1) the incremental O&M expense and depreciation expense, associated with the AMI, as well as the carrying cost on the investment and on the deferred costs at its weighted average cost of capital" The Commission order also stated that "(t)he Company further maintains that the issuance of the requested accounting order will not prejudice the right of any party to address the prudency of costs in a subsequent general rate case proceeding." The Company provided ORS with support for a deferral balance of $1,403,000 consisting of $802,000 in

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 12 of 16

deferred cost of capital, $560,000 in deferred depreciation expense, and $41,000 in after-tax return on deferred costs. The Company proposes amortizing this deferral balance over a three year period, and including the balance less one year of amortization in rate base.

ORS proposes a deferral balance of $1,562,000 which will provide the Company a recovery of the same deferred cost of capital and deferred depreciation expense as the Company's proposal, but does not include a return on those deferred costs. ORS recommends the deferred cost of capital portion of the deferral balance be included in rate base. ORS does not recommend that the deferred depreciation expense portion of the deferral balance be included in rate base. ORS's recommendation to include the deferred cost of capital portion of the deferral in rate base, and exclude the deferred depreciation expense from rate base is consistent with regulatory accounting practices for capital-related and operating-related costs. ORS's recommendation still allows the Company to recover its actual deferred costs through amortization of the proposed deferral balance which is a sufficient level of cost recovery. If the Company is allowed to include depreciation expense in rate base, the Company will earn a return on its depreciation expense.

ORS proposes amortizing the deferral balance over a period of 15 years. This amortization period was provided by the ORS Utility Rates Department, and is addressed in more detail in the testimony of ORS witness Willie Morgan.

Adjustment #30 – Adjust for Customer Connect Additional Expense and Deferral

The Company proposes to adjust other O&M by $1,227,000, depreciation and amortization expense by $515,000, income taxes by ($435,000), working capital investment by $1,029,000, and accumulated deferred taxes by ($257,000) to adjust for Customer Connect additional expenses and to amortize deferred costs. ORS proposes to adjust

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 13 of 16

depreciation and amortization expense by $308,000 and income taxes by ($77,000) to adjust for the amortization of deferred costs related to Customer Connect.

Commission Order No. 2018-553 granted the Company's request to defer "incremental O&M expenses associated with the deployment of the Customer Connect program as well as the carrying cost on the deferred costs at its weighted average cost of capital" The Commission order also stated "(t)he Company further maintains that the issuance of the requested accounting order will not prejudice the right of any party to address the prudency of costs in a subsequent general rate case proceeding." The Company provided ORS with support for a deferral balance of $1,544,000 consisting of $718,000 in actual deferred O&M expenditures as of September 30, 2018, $759,000 in estimated deferred O&M expenditures between October 1, 2018 and May 31, 2019, and a calculated weighted average cost of capital return of $67,000. The Company proposes amortizing this deferral balance over a three year period, and including the balance less one year of amortization in rate base.

Additionally, the Company proposes adjusting other O&M expense by $1,227,000. This adjustment represents the difference between the Company's actual test year O&M expense attributable to the Customer Connect project of $160,000, and the Company's projected average annual O&M expense of $1,387,000 during the 2019 and 2020 years.

ORS proposes a deferral balance of $923,000 which consists of the Company's actual deferred O&M expenditures as of December 31, 2018. ORS does not recommend including the Company's estimated O&M expenditures in the deferral balance as they are not known and measurable. ORS does not recommend a return on any deferred expenses, and ORS does not recommend that any of the deferral balance be included in rate base since the balance

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 14 of 16

consists entirely of deferred O&M expense. ORS's recommendation to exclude the actual deferred O&M expense from rate base is consistent with regulatory accounting practices for operating-related costs. ORS's recommendation still allows the Company to recover its actual deferred costs through amortization of the proposed deferral balance which is a sufficient level of cost recovery. If the Company is allowed to include deferred O&M expenses in rate base, the Company will earn a return on its O&M expenses.

The Company proposes to increase other O&M expense by $1,227,000 which the Company identified as an estimate. The Company should not be allowed to recover estimated or projected O&M expenditures as they are not known and measurable. The Company recorded $160,000 in actual O&M expense during the test year attributed to the Customer Connect project and ORS recommends approval of these known and measurable expenses.

Adjustment #35 – Amortize Deferred Cost Balance Related to South Carolina Grid

The Company proposes to adjust depreciation and amortization expense by $1,164,000, income taxes by ($291,000), working capital investment by $1,164,000, and accumulated deferred taxes by ($291,000) to amortize the deferred cost balance related to SC grid. ORS proposes to adjust depreciation and amortization expense by $424,000, income taxes by ($106,000), working capital investment by $1,016,000, and accumulated deferred taxes by ($253,000) to amortize the deferred cost balance related to South Carolina grid.

Commission Order No. 2018-751 granted the Company's request "to defer the incremental Operating and Maintenance ("OAM"), depreciation and property taxes associated with certain capital assets installed as part of its Power/Forward work, as well as the carrying cost on the investment and on the deferred costs at each utility's weighted

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 15 of 16

average cost of capital." The Commission order also stated "the issuance of the requested accounting order would not prejudice the right of any party to address the prudency of these costs in the Companies' next general rate case proceeding." The Company provided ORS with support for a deferral balance of $2,329,000 consisting of $1,266,000 in deferred cost of capital, $979,000 in deferred depreciation, O&M, and property tax expenses, and $84,000 in after-tax return on deferred costs. The Company proposes amortizing this deferral balance over a two year period, and including the balance less one year of amortization in rate base.

ORS proposes a deferral balance of $2,118,000 which will provide the Company a recovery of the same deferred cost of capital, deferred depreciation, deferred O&M, and deferred property tax expenses as the Company's proposal, but does not include a return on those deferred costs. ORS recommends the deferred cost of capital portion of the deferral balance be included in rate base. ORS does not recommend that the deferred depreciation, O&M, and property tax expense portion of the deferral balance be included in rate base. ORS's recommendation to include the deferred cost of capital portion of the deferral in rate base, and exclude the deferred depreciation, O&M, and property tax expenses from rate base is consistent with regulatory accounting practices for capital-related and operating-related costs. ORS's recommendation still allows the Company to recover its actual deferred costs through amortization of the proposed deferral balance which is a sufficient level of cost recovery. If the Company is allowed to include depreciation, O&M, and property tax expense in rate base, the Company will earn a return on these expenses.

ORS proposes amortizing the deferral balance over a period of 5 years. This amortization period was provided by the ORS Utility Rates Department, and is addressed in more detail in the testimony of ORS witness Anthony Sandonato.

Q. WILL YOU UPDATE YOUR TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information become available not previously provided by the Company.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ELECTRONICALLY FILED - 2019 March 4 4:38 PM - SCPSC - Docket # 2018-318-E - Page 16 of 16

ELECTRONICALLY FILED - 2019 April 9 3:33 PM - SCPSC - Docket # 2018-318-E - Page 1 of 2

ERRATA SHEET OF

ZACHARY J. PAYNE

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-318-E

IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS AND REQUEST FOR AN ACCOUNTING ORDER

The following changes are made to my Direct Testimony:

Direct Testimony

Page 2 of 16, lines 15-27:

"The Governmental Accounting Standards Board's (GASB) statement No. 62 provides, among other things, general standards of accounting for the effects of regulation and states that:

> A regulated business-type activity should capitalize all or part of an incurred cost that otherwise would be charged to expense if both of the following criteria are met:
> a. It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.
> b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs.

In other words, GASB identifies the key criteria the utility must meet to capitalize costs through an approved regulatory asset as:"

Should read:

ELECTRONICALLY FILED - 2019 April 9 3:33 PM - SCPSC - Docket # 2018-318-E - Page 2 of 2

"The Financial Accounting Standards Board's ("FASB") ASC 980 provides, among other things, general standards of accounting for regulated operations and ASC 980-340-25-1 specifically states that:

> An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:
> a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.
> b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs.

In other words, FASB identifies the key criteria the utility must meet to capitalize costs through an approved regulatory asset as:"

Page 3 of 16, lines 4-8:

"GASB statement No. 62 also indicates the utility should accrue 'carrying charges' on the regulatory asset:

During the period between the date on which the new asset is recognized and the date on which recovery begins, the carrying amount should be increased by accruing a carrying charge." Should be removed.

Page 3 of 16, line 9:

Replace "GASB" with "FASB".

Page 9 of 16, lines 4-7:

"ORS also agrees with the Company's proposal to accrue a return on the balance as GASB Statement 62 directs regulated businesses such as the Company to accrue a carrying charge on deferred cost regulatory assets from the time the assets are created until recovery of the asset begins." Should be removed.

[Please note: The correction noted herein reflects the testimony of the witness during the hearing in this matter.]

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 1 of 12

SURREBUTTAL TESTIMONY OF

ZACHARY J. PAYNE

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-318-E

IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS AND REQUEST FOR AN ACCOUNTING ORDER

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Zachary J. Payne. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina, 29201. I am employed by the South Carolina Office of Regulatory Staff ("ORS") in the Audit Department as a Senior Auditor.

Q. ARE YOU THE SAME ZACHARY PAYNE WHO PRESENTED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes. I pre-filed direct testimony related to ORS's findings and recommendations for certain adjustments in this proceeding on March 4, 2019.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my surrebuttal testimony is to address certain issues raised in the rebuttal testimonies of Duke Energy Progress, LLC ("Company" or "DEP") witnesses Laura A. Bateman, Robert B. Hevert, and Dr. Julius A. Wright. In my surrebuttal testimony, I will address the Company's position regarding the assertion the Company is "entitled" to a return

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 2 of 12

on deferred expenses until the money spent is fully recovered. I will also clarify the Company's mischaracterizations of my direct testimony. The issues I am addressing in surrebuttal are specific to Company and ORS Adjustments 17, 18, 19, 30, and 35, all of which are related to accounting deferrals.

Q. WILL ORS'S RECOMMENDED TREATMENT OF THE COMPANY'S ACCOUNTING DEFERRALS ADDRESS THE CONCERNS OF THE USING AND CONSUMING PUBLIC, ALL CLASSES OF CUSTOMERS, AND ALLOW THE COMPANY TO CONTINUE TO PROVIDE RELIABLE AND HIGH-QUALITY SERVICE?

A. Yes.

Q. PLEASE EXPLAIN WHY.

A. ORS's proposals represent a reasonable and equitable approach to the Company's recovery of deferred costs. ORS's recommendations allow the Company to include costs that were largely incurred outside of the Test Year, by including approximately $5,000,000 in amortization expense and a net adjustment to rate base of approximately ($13,000,000) in unamortized deferral balances in rate base. As illustrated in the table below, the ORS's recommended accounting treatment contributes approximately $3,500,000 to the ORS proposed revenue increase of $32,130,000 or more than 10%. In comparison, the Company's proposals related to recovery of deferred balances included approximately $16,000,000 in amortization expense and a net adjustment to rate base of approximately $21,000,000. The Company's recommended treatment contributes roughly $18,000,000 (more than 25%) to the Company proposed revenue increase of $68,668,000.

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 3 of 12

Table 1.1 – Proposed Treatment of Accounting Deferrals			
	ORS Proposal	Company Proposal	Difference
Amortization Expense	$5,000,000	$16,000,000	($11,000,000)
Net Impact to Rate Base	($13,000,000)	$21,000,000	($34,000,000)
Resulting Revenue Requirement	$3,500,000	$18,000,000	($14,500,000)
Total Revenue Requirement	$32,130,000	$68,668,000	($36,538,000)

The majority of Company's witnesses Bateman, Hevert and Wright rebuttal testimony addresses the issue of return on deferred costs and rate base treatment for the accounting deferrals. For comparison purposes, ORS calculated the difference from the Company's proposal based solely on the aspect of a return on deferred costs and rate base inclusion. If ORS's recommendations incorporated the same amortization periods as the Company, and did not include a change to the allowable coal ash costs, ORS's reduction to the Company's revenue requirement based on the ORS recommended accounting treatment of deferred balances would have been approximately $900,000. The ORS recommended accounting treatment for deferrals is a relatively minor reduction to the Company's operating experience.

Q. WHAT SOUTH CAROLINA STATUTES OR REGULATORY STANDARDS GOVERN THE RECOVERY OF A COST OF CAPITAL RETURN ON A DEFERRAL BALANCE?

A. I am not aware of any South Carolina statutes or regulatory standards that govern recovery of a cost of capital return on a deferral balance. Therefore, the Public Service

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 4 of 12

Commission of South Carolina ("Commission") has the duty to determine the most equitable treatment of the deferral balances for the customers and the Company.

Q. WHAT JUSTIFICATION DOES THE COMPANY OFFER FOR INCLUSION OF A COST OF CAPITAL RETURN ON THE RECOVERY OF THE DEFERRAL BALANCES?

A. The Company witnesses do not offer, in rebuttal testimony, a South Carolina statute or accounting standard to support the Company's inclusion of cost recovery of the weighted average cost of capital ("WACC") in the recovery of the deferral balances in Adjustments 17, 18, 19, 30, and 35. Outside of the coal ash cost disallowance proposed by ORS witness Dan Wittliff, the main point of disagreement between the Company and ORS is the issue of whether the customers should pay the Company the WACC on the Company's deferred costs.

The Company claims deferred costs were 100% financed by debt and equity because the deferred costs were not included in the Company's cost of service. Therefore, the Company asserts it should be allowed to recover financing costs by calculating a WACC return on deferred costs and include unamortized balances in rate base to earn a return going forward.

Q. DOES ORS AGREE WITH THE COMPANY'S JUSTIFICATION FOR INCLUSION OF A RETURN ON THE DEFERRED BALANCE?

A. No. ORS recommends the Commission apply the proper accounting treatment to the expenses contained in the deferral balances as it would absent the deferral account. This requires the deferral balances to be separated into two (2) categories: operating-related costs and capital-related costs. The rates and revenue requirement are designed by

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 5 of 12

the Commission to provide the Company a reasonable opportunity to recover prudently incurred operations and maintenance ("O&M") expenses and a fair and reasonable return on its capital investments to provide customers with reliable and high-quality service.

The rebuttal testimonies of Company witnesses Bateman, Wright, and Hevert failed to acknowledge the Company collected $562,000,000 in operating revenues from South Carolina customers per the Application. These revenues were paid to the Company by South Carolina customers during the 2017 test year through service rates that were designed to allow recovery of the Company's operating costs as well as provide a reasonable return on shareholders' capital investments.

Q. PLEASE EXPLAIN ORS'S RECOMMENDATIONS FOR COST RECOVERY TREATMENT FOR THE COMPANY'S DEFERRED BALANCES.

A. The determination of what, how and over what time period a utility receives cost recovery for accounting deferrals through service rates is ultimately within the discretion of the Commission. As I stated in my direct testimony, with the exception of the coal ash cost disallowances proposed by ORS witness Dan Wittliff, ORS recommends no additional adjustments to the actual costs incurred and deferred by the Company. ORS's recommendation achieves an equitable result that allocates deferred costs fairly between the Company's customers and the Company's shareholders.

Q. WHAT REGULATORY AND/OR ACCOUNTING STANDARDS DO OTHER STATE COMMISSION'S APPLY TO THE RECOVERY OF DEFERRED BALANCES?

A. ORS's research indicates regulatory asset recovery through service rates has been decided by state commissions largely on a case by case basis. In addition, ORS did not find

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 6 of 12

specific statutes in South Carolina that address the treatment of regulatory accounting deferrals. Historic orders issued by the Commission included various methods of deferral balance recovery. Based on ORS's research, ORS concludes, cost recovery for deferred balances is determined by state Commissions on a case by case basis.

Q. WHAT METHODS DO OTHER STATE COMMISSIONS UTILIZE TO DETERMINE COST RECOVERY TREATMENT FOR ACCOUNTING DEFERRALS?

A. The Minnesota Public Utility Commission applies a standard for the establishment of accounting deferrals and all components of the standard must be met to establish an accounting deferral. The standard is:

1. The expense must be related to utility operations for which ratepayers have incurred costs or received benefits;
2. It must be significant in amount;
3. It must be associated with unusual or extraordinary items; and
4. It is subject to review for reasonableness and prudence.

The New York Public Service Commission uses a similar, three-part test when considering approval of accounting deferrals which includes a test to determine if the extraordinary expenses are "material to earnings" (greater than 5% of income for shareholders). In Connecticut, utilities are not allowed to incur carrying costs in deferral balances until recovery begins. In New Hampshire, the decision to allow carrying costs on a deferred balance is decided case by case, but the New Hampshire Public Utilities Commission does not allow the deferral balances to be included in rate base. In Utah, much

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 7 of 12

like South Carolina, the Public Service Commission has no formal regulatory guidelines or standards and prefers to determine the treatment of deferrals on a case by case basis.

Q. COMPANY WITNESS BATEMAN DEFINED DEFERRED COSTS AS COSTS THE COMPANY INCURRED AND NOT CURRENTLY RECOVERED THROUGH RATES. DO YOU AGREE WITH THIS DEFINITION?

A. No. In many instances, the Company used deferral accounting treatment to preserve the Company's ability to recover expenses incurred outside of the Test Year in the next general rate proceeding. Company witness Bateman overlooks some very important criteria related to accounting deferrals.

A utility should be granted accounting deferrals for costs that meet a level of "extraordinary" in terms of circumstance and magnitude.[X] Meaning, the costs should be non-recurring, unforeseen, and out of management's control, such as uninsured storm damage, losses from early retirement of major plant assets (not provided for in depreciation) or environmental and regulatory remedies imposed by local, state or federal governments. The Federal Energy Regulatory Commission ("FERC") Electric Chart of Accounts (page 286) states that in order to be considered extraordinary, an item should be more than approximately 5% of a utility's income, computed before extraordinary items.

ORS does not believe the Company's projects for which it has deferred costs such as Customer Connect, Grid Mod, and installation of AMI meters meet any of these criteria to be considered extraordinary. ORS has taken an equitable approach and recommends recovery of the costs actually incurred by the Company; however, ORS recommends the

[X] Deloitte, Regulated Utilities manual | Service for regulated utilities at FERC (Feb. 2009), http://ipu.msu.edu/wp-content/uploads/2017/09/Deloitte-Regulated-Utilities-Manual-2010-2.pdf

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 8 of 12

Commission not allow the Company to shift a burden onto its customers while its shareholders earn a cost of capital return on the non-extraordinary deferred operating costs.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH COMPANY WITNESS BATEMAN'S DEFINITION OF DEFERRED COSTS.

A. Company witness Bateman's definition is very broad, and if strictly applied, may encourage the Company to seek more accounting deferrals for O&M costs in the future that are not classified as extraordinary. In South Carolina, a regulated utility's rates are established based on a historical test year adjusted for known and measurable changes. Since no one can predict the future, rates will often not represent all the specific operating costs that will be incurred by the Company during the time the rates are in effect. Without proper guardrails or guidelines related to accounting orders, the Commission may inadvertently allow utilities to reduce regulatory lag and shift risk to customers by establishing accounting orders for non-extraordinary expenses that occur outside of a historic test year.

The impact of this practice will be greatly inflated costs in future years which will be passed on to customers through rates. The impact will be greater if the utility is allowed to earn a cost of capital return on deferred O&M costs, during the time in which the O&M costs are deferred and while the O&M costs are amortized. This compounding of a return within the recovery of the deferred balance creates a situation where the utility earns a return on regulatory assets for the sole purpose to benefit their shareholders at the direct expense of the Company's customers.

Q. DO YOU AGREE WITH COMPANY WITNESS BATEMAN'S CHARACTERIZATION THAT ORS'S RECOMMENDATIONS ARE PUNITIVE?

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 9 of 12

A. No. Company's witness Bateman's characterization that ORS's recommendations are "punitive" is meant to convey the Company will suffer harm – which is not true. ORS's recommendation to allow the Company to receive recovery of its incurred expenses outside of the Test Year is fair and equitable. ORS recommends the Commission limit the Company's recovery to the operating expenses because the Company provides no justification for financing daily operations. The Company should not be allowed to shift its risk to the customers through the allowance of a cost of capital return on O&M expenses. Allowing the Company a return on deferred O&M expenses would not only allow the Company to recover out of test period expenses, but also gives it a return on expenses that it would not have earned had the expense been incurred within the test period. ORS recommends the Commission approve normalized annual operating expenses for the Company including approximately $5,000,000 of amortization expense to recover deferred costs which were not incurred during the Test Year. Absent specific Commission guidelines or guardrails to govern deferral balance recovery, ORS recommends an equitable allocation of the deferred balance of O&M between the customers and shareholders.

Q. DID ORS CONSIDER OTHER ALTERNATIVES FOR TREATMENT OF COST RECOVERY RELATED TO ACCOUNTING DEFERRALS?

A. Yes. ORS evaluated an alternative recommendation which would limit the Company's cost recovery of the deferred balances to the actual deferred costs. This alternative would not allow the Company any rate base treatment of capital-related costs. ORS did not advance this recommendation as it concluded it did not equitably allocate

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 10 of 12

costs and may negatively impact the Company's investment in and maintenance of utility facilities to provide reliable and high-quality utility services.

Q. IS THE COMMISSION REQUIRED TO ACCOUNT FOR THE TIME VALUE OF MONEY IN ITS DETERMINATION OF COST RECOVERY FOR DEFERRED BALANCES?

A. Company witness Wright asserts that ORS's recommendation is flawed because it does not account for the fact "these dollars were not borrowed from investors for free." ORS's recommended adjustments to deferred balances generously provide a return of and a return on capital-related costs. However, as stated in in my surrebuttal testimony, ORS does not agree that deferred O&M costs should earn a return. The Company should not be allowed to shift its risk to the customers through the allowance of a cost of capital return on O&M expenses. Allowing the Company a return on deferred O&M expenses would not only allow the Company to recover out of test period expenses, but also gives it a return on expenses that it would not have earned had the expense been incurred within the test period.

Q. DO YOU AGREE WITH COMPANY WITNESS BATEMAN'S SUGGESTION THAT ORS'S RECOMMENDED TREATMENT FOR THESE ACCOUNTING DEFERRALS SHOULD BE APPLIED TO OTHER REGULATORY ASSETS AND LIABILITIES?

A. No. ORS concludes cost recovery for deferred balances is determined by state Commissions on a case by case basis. Company witness Bateman argues that ORS's proposed treatment of these six (6) accounting deferrals, should also be applied to a regulatory liability, such as accumulated deferred income tax ("ADIT"). Unlike other

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 11 of 12

regulatory assets, ADIT has a prescribed accounting treatment which is documented in regulatory and accounting publications and guidelines. For instance, *Accounting for Public Utilities* states "[t]he general view in this respect is that these liabilities represent a source of interest-free funds supplied by the U.S Treasury that the utility is free to use in support of rate base investment. Therefore, the rate base must be reduced by accumulated deferred income tax ("ADIT") liabilities balance to avoid paying a return on funds that are cost free."[2] Additionally, the NARUC *Rate Case and Audit Manual* states "[u]nder Statement of Financial Accounting Standards (SFAS) 109, Accounting for Income Taxes, companies must recognize changes in tax rates when they occur and use deferred tax accounting. The resulting comprehensive interperiod tax allocation, or income tax normalization, cause a rate base adjustment that is amortized over the tax life of the timing difference."[3] The six (6) accounting deferrals for which the Company is seeking recovery in this docket, do not have defined procedures established to determine the regulatory accounting treatment.

Q. WHY IS THE EIGHT (8) YEAR AMORTIZATION PERIOD FOR THE HARRIS COLA DEFERRAL BALANCE APPROPRIATE?

A. ORS's recommendation for an eight (8) year amortization period for the Harris COLA deferral matches the return of the funds by customers over the time period in which the costs were incurred.

Q. WILL YOU UPDATE YOUR SURREBUTTAL TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

[2] Robert L. Hahne & Gregory E. Aliff, *Accounting for Public Utilities*, § 4.04[9] (2018).
[3] NARUC Staff Subcommittee on Accounting and Finance, *Rate Case and Audit Manual, pg. 24 (2003)*

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information become available not previously provided by the Company.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 12 of 12

notice to the public at large nor a hearing is required regarding this petition." Have I read that correctly?

A (PAYNE) Yes, sir. You have.

Q And, based on your study and review of -- of -- of the matters at issue in this docket, you understand that the Commission did not issue a notice to its ratepayers concerning this petition for an accounting order, did it?

A (PAYNE) I don't believe they did.

Q And you also know that there was no hearing held on this matter, that the Commission issued this order based on correspondence from the ORS and the -- and the application of -- of the applicant here, correct?

A (PAYNE) That is my understanding, yes.

Q And, in this -- again, in the same docket -- the same petition, the Company alleged -- alleges that, "The accounting order granting relief DEP seeks in this petition will not preclude the Commission from addressing the reasonableness of the cost deferred in -- in regulatory asset and liability accounts in the next general rate proceeding," correct?

A (PAYNE) Yes.

Q And the Commission approved the deferral request in

that correct?
A (PAYNE) The -- the 68 million is the total revenue requirement they requested. The $18 million figure just above that -- that is what they have requested for the five adjustments related to deferrals.
Q All right. So -- and the ORS position is that the Company should be entitled only to $3.5 million, as -- as opposed to the $18 million, correct?
A (PAYNE) Yes. That was the resulting revenue requirement that we calculated based on our position.
Q And, if I understand these deferrals correctly, if the Commission grants either your number or the Company's number, they're going to get rate recovery going all the way back retroactively to, in the case of the petition I read to you, 2013, correct?
A (PAYNE) Yes. Even the GridSouth, I believe, was costs incurred in 2001 or 2002, but that would be as far back as it goes.
Q So -- so, as a -- as a consequence, we're litigating 18-year-old issues today?
A (PAYNE) Yes.
Q And -- and -- and, certainly, no party is prejudiced in this proceeding from challenging a

Q Surrebuttal.
A (PAYNE) Okay.
Q And do you mind explaining that a little bit more for us? What do you mean by "operating-related costs" and "capital-related costs"?
A (PAYNE) Yes. I think probably the best way to explain it would be to turn to Mr. Kelvin Major's Exhibit KLM-1, if you have that available. It could be direct or surrebuttal. I'll go to direct.
Q Why don't you paraphrase it for me, if you don't mind?
A (PAYNE) Okay. So, basically, if you look at KLM-1, you have a -- a line about in the center of the page there that is the total operating income for return -- or I'm sorry -- the net operating income for return. And, essentially, the way we categorize things is anything above that line is O&M, and anything below that line is rate base.
Q Okay. And so what -- so what kinds of expenses would O&M expenses be?
A (PAYNE) Generally, every expense that's not a capital asset expenditure.
Q Things like call center costs?
A (PAYNE) Yes. Call center costs. I mean, the -- I imagine the point you're getting to: depreciation,

income taxes, purchase power, a lot of things would go into that category.

Q Okay. And when I think about the costs that were requested for deferral --

A (PAYNE) Uh-huh.

Q -- do you know of any operating-related costs in the Customer Connect balance that would exist but for the capital being deployed for the program?

A (PAYNE) My understanding -- I -- I will say my initial reaction was that Customer Connect was a capital expenditure; however, the -- your Company's own testimony referred to those costs as incremental O&M and, therefore, that is the position that we took: that they are incremental O&M costs.

Q And did you ask about what kinds of things that incremental O&M went to? what kind of -- what kinds of tasks those costs were for?

A (PAYNE) No. But I generally understood it to be the development of the new software system.

Q Okay. And so those costs to develop -- those O&M costs to develop the new software system would not exist without the capital costs related to the software system?

A (PAYNE) That is fair to say.

Q Okay. And so then this Commission could view that as a capital-related cost for purposes of deferrals?
A (PAYNE) If it's going to be charged to your rate base, then yes, and if not, then no.
Q Okay. And -- and thank you. And so when I think about AMI, would the Company have any O&M expenses in this AMI bucket but for the deployment of the capital -- capitalized technology?
A (PAYNE) There's a distinction to be made here that you have the capital assets themselves that are the AMI meters and they go into rate base. The Company earns a return on those capital expenditures through the rates as allowed by the Commission. However, there are O&M costs associated with operating those meters as there are with -- pretty much all O&M costs are related to some function -- a lot -- well, you have -- basically, all of your assets have maintenance costs that arise from them, so if you're trying to draw the connection between the capital costs that are in the rate base and the O&M, yes, there is a connection there; however, the O&M expenses, as they are booked to O&M accounts, do not earn a return on those expenses.
Q Right. And I understand that.

PROCEEDINGS

CHAIRMAN RANDALL: Please be seated. Good morning. We'll call the hearing back to order, and I think it's the next witness for ORS.

MR. KNOWLES: Yes, sir, Mr. Chairman. Thank you. ORS calls, as its next witnesses, the panel of Steve Hamm and Willie Morgan.

(Witnesses affirmed)

THEREUPON came,

STEVEN W. HAMM,

WILLIE J. MORGAN, PE,

called as witnesses, who, having been first duly affirmed, were examined and testified as follows:

DIRECT EXAMINATION

BY MR. KNOWLES:

Q Okay. Good morning, Mr. Hamm and Mr. Morgan. Mr. Hamm, let's start with you, please. Would you please state your full name and occupation for the Commission?

A (HAMM) Yes. My name is Steven Hamm.

CHAIRMAN RANDALL: Cut your microphone on. There you go.

WITNESS HAMM: Thank you.

A (HAMM) My name is Steve Hamm, and I have served as

special counsel and senior advisor at the Office of Regulatory Staff.

Q Can you briefly summarize for the Commission your background and experience in the field of utility regulation?

A (HAMM) I think my best summary is that I argued my first case, which was a Duke case, in the summer of 1978, and I have participated in literally hundreds of hearings, and I've argued regulatory cases in the circuit court and before the Supreme Court on about 40 occasions.

Q Thank you, sir. And are you the same Steve Hamm who prefiled 11 pages of surrebuttal testimony in Docket Number 2018-318-E on March 25th, 2019?

A (HAMM) Yes, sir. I'm the same.

Q Do you have any changes, edits, or corrections to your prefiled surrebuttal testimony?

A (HAMM) No, sir.

Q And if I asked you today the same questions as those posed in your prefiled surrebuttal testimony, would your answers be the same?

A (HAMM) Yes, sir.

MR. KNOWLES: Mr. Chairman, ORS had originally filed both public and redacted versions of Mr. Hamm's testimony and, subsequently, filed a

revised redacted version of Mr. Hamm's surrebuttal on April 9th. After consultation with counsel for the Company, ORS understands that the Company does not object to Mr. Hamm's testimony being made public, and as a result, ORS asks that the prefiled surrebuttal testimony of Steve Hamm be read into the record in its entirety as if given orally from the stand.

CHAIRMAN RANDALL: Okay. Mr. Hamm's prefiled surrebuttal testimony will be read into the record as though given orally from the stand.

MR. KNOWLES: Thank you.

Q And, Mr. Hamm, did you also file four surrebuttal exhibits marked SWH-1 through SWH-4 as attachments to your surrebuttal testimony?

A (HAMM) Yes, sir. I did.

Q And were portions of your Surrebuttal Exhibits SWH-1 and SWH-2 marked as confidential at the request of the Company and pursuant to SC code annotated 58-4-55?

A (HAMM) Yes, sir. At the time, they were marked confidential.

Q Do you have any changes, edits, or corrections to your prefiled surrebuttal exhibits?

A (HAMM) No, sir.
Q Okay. Thank you.
MR. KNOWLES: Mr. Chairman, it's ORS's understanding that the Company no longer claims confidential treatment of Surrebuttal Exhibits SWH-1 and SWH-2, and for that reason, ORS asks that the prefiled -- excuse me -- Surrebuttal Exhibits SWH-1 through SWH-4 of Steve Hamm be entered into the record without redactions as the next hearing exhibit.
CHAIRMAN RANDALL: Okay. The -- Mr. Hamm's Surrebuttal Exhibits SWH-1 through 4 will be entered as Exhibit Number 67.
MR. KNOWLES: Thank you, sir.
(WHEREUPON, Hearing Exhibit 67 was marked and received in evidence.)
Q Mr. Hamm, have you prepared a summary of your testimony?
A (HAMM) Yes, sir. I have.
Q Could you please provide a brief overview of your surrebuttal testimony in this proceeding?
A (HAMM) Yes, sir.
Mr. Chairman and members of the Commission, good morning. My testimony addresses one of the critical issues now before this Commission. ORS's

recommendation to disallow certain DEP legal expenses properly serves to encourage careful contract negotiation and complete management understanding of all provisions of the agreement. ORS's position to disallow legal expenses helps to align the costs and benefits of entering into agreements and litigation and ensures that the Company carefully manages its operations and considers the cost that pursuing litigation could potentially have for its customers. Sound policy requires that the Company should not be able to insulate its ratepayers by externalizing costs to customers. DEP management failed to meet its legal and operations obligations when the North Carolina business court ruled, last August, that DPA [sic] failed to successfully defend its positions regarding the meaning of certain terms of the DEP agreement with CertainTEED. Management failure to vindicate its position resulted in DEP agreeing to pay CertainTEED almost $90 million in liquidated damages. DEP's management failure cannot be the responsible -- responsibility of DEP customers who had no participation in any acts -- in any aspects of the negotiated agreement.

My testimony addresses the Company legal

expense recovery position presented in the testimony of DEP witnesses. The Company suggests that all the legal expenses the Company included in this case are fair and reasonable and should be approved by this Commission. However, the Company bears the regulatory burden to provide substantial evidence to the Commission that any proposed legal expense should be paid by Company customers and not shareholders. The Company has not met that basic regulatory requirement regarding the legal expenses sought in this case.

The public policy role of this Commission is to carefully examine an expense before any decision regarding approval of any expense. In this matter, ORS recommends that the Commission first examine the legal expense in question and then determine why that expense was incurred by the Company in the first place. Was a legal expense incurred because the Company was charged with violations of applicable law in connection with its operations? If so, the Commission needs to be presented with the detailed facts of the alleged violation and the operating conduct of the Company before allegations of violation of law were raised by whatever legal authority or customer involved. Management

decisions and conduct are directly relevant in determining if customers should be forced to pay any legal -- specific legal expenses in their electric rates. This Commission has already demonstrated in the recent CWS case that it is prepared to reject company legal expenses resulting from operating violations in the operation of the company.

The South Carolina Supreme Court has previously ruled that the Commission should not reward a company for violations of operating standards, whether state or federal. Fair and reasonable rates should not include expenses solely the responsible -- responsibility of actions of management. In this case, the Company has provided no cogent and relevant evidence regarding the legal expenses that ORS has challenged. ORS is recommending that the Commission reject treating our positions and legal expenses as an allowable regulatory expense in this case.

The Company provided very vague justification for the coal ash litigation expenses that ORS is challenging. Those justifications do not address the reason the expenses were incurred initially. From reviewing the documents, the Commission only

knows a limited and insufficient amount of information from the legal-expense information supplied by the Company. DEP has not provided the Commission with specific and understandable information demonstrating that all expenses should be paid for by DEP customers in the first place. The term "substantial evidence" doesn't -- that does not include the reason the legal expense was incurred in the first place is not the substantial evidence required by decisions issued by the South Carolina Supreme Court.

Sound regulatory policy needs to be consistently applied based on evidence presented to the Commission. ORS's recommendation on this issue are consistent with the policy applied in the CWS case, and are consistent with the decisions issued by the South Carolina Supreme Court. A regulatory policy employed by this Commission can only be relevant if it is consistently employed in ratemaking decisions.

Q Thank you, Mr. Hamm.

(PURSUANT TO PREVIOUS INSTRUCTION, THE PREFILED SURREBUTTAL TESTIMONY OF STEVEN W. HAMM FOLLOWS.)

SURREBUTTAL TESTIMONY

AND EXHIBITS

OF

STEVEN W. HAMM

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-318-E

IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS AND REQUEST FOR AN ACCOUNTING ORDER

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Steven W. Hamm. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina 29201. I am employed by the State of South Carolina as Special Counsel and Senior Advisor, in the Legal Department of the South Carolina Office of Regulatory Staff ("ORS").

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA?

A. Yes. I appeared as Legal Counsel in my first contested case hearing before the Public Service Commission of South Carolina ("Commission" or "PSC") over 40 years ago, in the summer of 1978. At that point, I served as State Deputy Consumer Advocate and head of the newly created Division of Consumer Advocacy at the South Carolina Department of Consumer Affairs. I was named Administrator and State Consumer Advocate for the Department in 1981 by the Commission on Consumer Affairs. I served

at the Department of Consumer Affairs for almost 18 years and left the Department to enter the private practice of law in 1994. I represented many regulated entities before the Commission during my 24 years in private practice. I have appeared before the Commission in various types of regulatory proceedings. I left private practice and joined ORS in September 2018.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address the regulatory policy issues related to certain legal expenses sought by Duke Energy Progress, LLC ("DEP" or "Company") which are addressed in the rebuttal testimony of DEP witness Laura Bateman, Dr. Julius Wright and Barbara Coppola. I will discuss why ORS recommends the Commission disallow cost recovery from customers for those identified legal expenses.

Q. HAS REGULATORY PUBLIC POLICY CHANGED AND EVOLVED DURING YOUR CAREER OF APPEARING BEFORE THE COMMISSION?

A. Yes. I have been directly involved in working to shape and revise the regulatory public policy standards that serve to guide the Commission in evaluating rate making positions advanced by regulated companies. Rulings by the South Carolina Supreme Court in response to appeals of Commission orders have been a significant factor in how the Commission decides contested issues.

Q. WHAT CHANGES HAVE YOU OBSERVED DURING THE PAST 40 YEARS OF APPEARING BEFORE THE COMMISSION?

A. The Commission has modified policy positions in response to efforts by regulated companies to claim that a utility should be able to recover all costs of operations from ratepayers, regardless of who benefitted from those expenses.

Q. CAN YOU PROVIDE THE COMMISSION WITH AN EXAMPLE?

A. Yes. In a recent Carolina Water Service, Inc. ("CWS") rate case, the Commission addressed whether the contested proposed legal expenses should be paid by customers. Based upon the record testimony and evidence, the Commission ruled that certain CWS litigation expenses should be assigned to stockholders and not customers.[1]

Q. HOW WOULD YOU DESCRIBE THE CURRENT LEGAL EXPENSE REGULATORY POLICY ADOPTED BY THE COMMISSION?

A. I believe the current Commission approach to examine proposed legal expense recovery is focused on a determination of whether the underlying legal expenses in question should be paid by customers. The Commission regulatory policy includes an examination of the legal expenses to determine if the Company's legal costs and expenses were the result of prior management decisions. The Commission will generally not include legal costs and expenses in rates paid by customers in legal disputes in which the Company was found at fault and was unable to reverse that finding of fault.

Q. WHY SHOULD MANAGEMENT DECISIONS AND ACTIONS AFFECT WHETHER OR NOT PROPOSED LEGAL EXPENSES SHOULD BE RECOVERED BY CUSTOMERS?

A. The rates and charges for public utility service in South Carolina are required by law to meet the regulatory standard of being both fair and reasonable to customers and provide a reasonable rate of return to Company investors. Those rates allow the Company to operate in a lawful manner. Company management is required to take all necessary steps to comply with applicable legal and regulatory requirements. Final Commission orders

[1] *Docket No. 2017-292-WS – Order 2018-802*

must reflect a proper application of Company and customers' interests which require a full examination of why those expenses were incurred in the first place. The South Carolina Supreme Court has confirmed and ruled that the Commission has the regulatory authority to reject portions of expenses previously incurred by a regulatory utility.[2]

Q. HOW DOES DEP ATTEMPT TO SUPPORT PAYMENT OF COAL ASH LITIGATION COSTS?

A. DEP filed Direct and Rebuttal Testimony for Dr. Julius Wright that briefly addressed coal ash legal costs related to insurance recovery litigation and the legal defense costs of North Carolina enforcement action.

Q. DOES DR. WRIGHT PROVIDE ANY SPECIFIC LEGAL DATA, COURT DECISIONS, OR OTHER INFORMATION TO JUSTIFY COAL ASH RELATED LEGAL EXPENDITURES BY DEP?

A. No.

Q. PLEASE EXPLAIN.

A. Dr. Wright makes no detailed presentation to justify that DEP wants its customers to pay all legal costs and expenses. Dr. Wright makes the broad assertion that "legal fees should be recoverable because they represent a legitimate, reasonable and prudent business expenditure." Dr. Wright does not explain why customers should pay the legal expenses including litigation expenses associated with a breach of contract case that resulted in an adverse court decision and later settlement. The legal expense information supplied by DEP is not case specific.

[2] *Utilities Services of SC v. SC Office of Regulatory Staff*, 392 S.C. 96, 708 S.E.2d 755 (2011).

Q. WHAT BASIS DOES DEP WITNESS BATEMAN OFFER TO THE COMMISSION?

A. Witness Bateman attempted to justify the vague and limited responses provided to ORS during discovery by defending the legal e-billing system used by the Company. The information contained in the Microsoft Excel print out provided no fundamental underlying data or information that could be used by ORS to confirm exactly which case, matter or issue was being billed to DEP. ORS advised that information was not sufficient to support the legal expenses in question. The Company provided no further detailed information. The Company is responsible for maintaining information in a manner that allows full regulatory examination.

Q. DOES ORS'S PROPOSED DISALLOWANCE PREVENT DEP FROM DEFENDING ITSELF FROM LAWSUITS?

A. No.

Q. PLEASE EXPLAIN.

A. DEP has provided no substantive information for any coal ash litigation expenses to justify customers being responsible for legal fees and costs. Every proposed legal expense is always subject to a disallowance by the Commission based on a variety of considerations. Shareholders should pay the costs for litigation defending the Company where the Company did not prevail on claims of violations of state and federal law and regulations.

Q. HAS THE COMMISSION DISALLOWED LEGAL EXPENSES?

A. Yes.

Q. PLEASE EXPLAIN.

A. The Commission recently disallowed certain legal expenses requested by CWS in a Reconsideration Order issued on January 25, 2019. The Commission declined to force customers to pay for the Company's legal expenses related to its failure to successfully overturn a federal court decision finding the Company in violation of the Clean Water Act.[3]

Q. HAVE YOU EXAMINED THE LITIGATION COSTS AND EXPENSES SOUGHT BY DEP IN THIS DOCKET?

A. Yes.

Q. SHOULD THE COMMISSION APPROVE ALL DEP LEGAL EXPENSES SOUGHT IN THIS PROCEEDING BASED ON THE VERY SUMMARY INFORMATION PROVIDED TO ORS DURING DISCOVERY?

A. No.

Q. PLEASE EXPLAIN YOUR RESPONSE TO THE COMMISSION.

A. As an initial policy approach, ORS recommends that the Commission first determine if the Company's proposed legal expense should be considered as a ratemaking operating expense to be included in rates authorized by the Commission. "When litigation involves claims asserting failure of the utility to adhere to state or federal law, we must look carefully at the matter to determine whether expenses associated with defending the action should be included in rates paid by customers." Docket No. 2017-292-WS, Order No. 2018-802 p.16

Q. ARE YOU SUGGESTING THAT A REGULATORY UTILITY MUST MEET A PERFECTION STANDARD IN ORDER TO OBTAIN COST RECOVERY FROM THE COMMISSION?

[3] *Docket No. 2017-292-WS – Order 2018-802*

A. No. The Commission has many years of experience examining complex cases from regulating a wide range of regulated entities. What has changed over my 40 years of experience before the Commission is the Commission now demands greater accountability and greater underlying data and information before it approves Company requests for rate adjustments.

Q. PLEASE EXPLAIN THE LITIGATION EXPENSES AT ISSUE IN THIS RATE PROCEEDING.

A. DEP seeks ratepayer recovery of certain coal ash litigation expenses. Most notable is the extremely summary explanation provided by DEP to ORS discovery inquiries.

DEP provided the very same limited written justification for several legal invoices for coal ash litigation expenses. The description of services for the legal invoice, as provided by DEP in its response to ORS states "legal fees and expenses related to potential insurance recovery for coal ash." Exhibits SWH-1 through SWH-4. The Company made no reference to existing litigation cases and disputes or court orders that were adverse to the Company. The Commission has no way, based upon Company responses, to know if some or all of the litigation expenses were defending claims that the Company violated state or federal law. The rates approved by the Commission require the Company to comply with all laws that apply to its operations.

Q. ARE THERE ANY DEP SUMMARIES FOR OTHER COAL ASH LEGAL EXPENSES?

A. Yes. DEP provided the following brief justification regarding multiple other listed coal ash legal expenses. The description for services performed stated "Defense of coal ash state enforcement litigation for DEP, LLC Sites based on alternative fee arrangement."

DEP did not address why ratepayers should pay those costs since the litigation was based on allegations of unlawful conduct by the Company.

Q. PLEASE EXPLAIN WHY ORS RECOMMENDS THE COMMISSION EXCLUDE LEGAL COST RECOVERY OF COAL ASH LEGAL INVOICES.

A. DEP has not provided the Commission or ORS with any clear and detailed information supporting its claim for recovery of hundreds of thousand dollars of coal ash litigation expenses. The brief DEP explanations merely advise the Commission that DEP is defending unnamed Company actions related to coal ash cases filed against DEP. The Commission only knows that DEP believes there may be "*potential* insurance recovery for coal ash" (emphasis added). DEP has not demonstrated that any of the coal ash litigation expenses merit inclusion in the rates that may be established by the Commission in this DEP proceeding.

Q. WHAT IF A LEGAL FORUM HAVING JURISDICTION OVER DEP RULES THAT THE MASSIVE DEP COAL ASH DISCHARGE IN NORTH CAROLINA WAS THE RESULT OF DEP MANAGEMENT FAILURE?

A. DEP has the legal obligation to file any existing orders or decisions relating to coal ash matters with the Commission. Sound regulatory policy should require the review of specific positions by DEP and in related litigation proceedings before the Commission has any basis to make final regulatory decisions on what coal ash related litigation costs or expenses, if any, should be included in DEP rates in South Carolina.

Q. DOES DEP SEEK RECOVERY OF ANY OTHER LITIGATION COSTS AND EXPENSES IN THIS DOCKET?

A. Yes. DEP seeks recovery for costs and expenses arising out of DEP's breach of a 2012 contract with CertainTEED Gypsum, Inc. This litigation is also discussed in the direct and surrebuttal testimonies of ORS witness Morgan. We know from a confidential settlement agreement that the Company paid substantial sums for breach of contract and substantial sums for liquidated damages. We do not know if any of those costs are included in this rate proceeding.

Q. WHY DOES DEP ASSERT THAT IT IS ENTITLED TO RECOVERY OF THESE LITIGATION COSTS AND EXPENSES?

A. Company witness Coppola asserts that the Company did not breach its contract and that any legal fees the Company incurs to defend itself in lawsuits are proper for recovery from customers. (*See* Coppola Rebuttal p. 5 ll. 8–16.) Witness Coppola provided no evidential basis for her claims.

Q. ARE THE REASONS FOR RECOVERY PROFFERED BY COMPANY WITNESS COPPOLA COMPELLING?

A. No. The overwhelming evidence shows that DEP breached the CertainTEED contract. There is a valid final judgment finding DEP was in breach that was not overturned and later settled by the Company paying enormous sums to CertainTEED (and at this point, will never be) overturned (*see* Exhibit WJM-2 at 77–82; Confidential Exhibit WJM-3); DEP paid approximately $1,084,000 for its breach. DEP also agreed to pay approximately $88 million in liquidated damages as part of its settlement with CertainTEED (*see*

Confidential Exhibit WJM-3).[4] Customers should not be held responsible for the Company's actions that led to a breach of contract that the Company and its management negotiated. And customers should not be held responsible for the Company's decision to pursue intensive litigation that ended in the Company agreeing to pay a total of approximately $90 million and to dismiss its appeal in order to put the matter behind it. (*See* Confidential Exhibit WJM-3). It is impossible to know, based on information supplied by DEP, if any of those legal expenses are present in this rate proceeding,

Q. DOES THE ORS POSITION DISCOURAGE THE COMPANY FROM ENTERING INTO CONTRACTS OR FROM PURSUING MERITORIOUS LITIGATION IF NECESSARY?

A. No. ORS's position helps to align the costs and benefits of entering into agreements such as the CertainTEED contract. Disallowing expenses where the Company breaches its agreements serves to encourage careful negotiation and assessment of the potential and the pitfalls of a particular agreement. It also helps to ensure that the Company carefully manage its operation and consider the costs that pursuing litigation could potentially have for its customers. Sound policy requires that the Company should not be able to insulate its shareholders by externalizing costs to customers.

Q. DOES ORS RECOMMEND THE COMMISSION APPROVE RATES WHICH INCLUDE THE ADVERSE COST IMPACTS RESULTING FROM POOR DEP MANAGEMENT DECISIONS?

[4] *Black's Law Dictionary defines liquidated damages as "[c]ash compensation, agreed to by signed, written contract for breach of contract, payable to the aggrieved party." (Available at: https://thelawdictionary.org/liquidated-damages/) (emphasis added).*

A. ORS believes the only sound regulatory policy answer is no. ORS recommends the Commission review and consider all relevant management and legal factors before it approves any specific expenses. The evolving regulatory environment and concerns from the General Assembly clearly point to the conclusion that Company management will not be rewarded for failure to comply with federal and state laws.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

THE EXAMINATION BY MR. KNOWLES CONTINUES.

Q Good morning, Mr. Morgan. Would you please state your full name and occupation for the Commission?

A (MORGAN) Good morning. My name is Willie Morgan, and I'm the deputy director for Utility Rates with the South Carolina Office of Regulatory Staff.

Q Thank you, sir. Are you the same Willie Morgan who prefiled nine pages of direct testimony in Docket Number 2018-318-E on March 4th, 2019?

A (MORGAN) Yes. I am.

Q Do you have any changes, edits, or corrections to your prefiled direct testimony?

A (MORGAN) Yes. I do.

Q Could you please identify those edits?

A (MORGAN) On Page 3 of 9 of my direct testimony, Line 16, the years that are given there, 2033 and 2034, should be changed to 2030 and 2046.

Q Thank you, Mr. Morgan. And if I asked you today the same questions as those posed in your prefiled direct testimony, subject to the changes you just indicated, would your answers be the same?

A (MORGAN) Yes, sir.

Q Thank you.

MR. KNOWLES: Mr. Chairman, ORS had originally filed a confidential version of Mr. Morgan's

testimony and a public version. ORS would ask that the publicly filed version of Mr. Morgan's testimony be read into the record as if given orally from the stand, subject to the change outlined by Mr. Morgan, and that the unredacted version be held under seal pending further order of the Commission.

CHAIRMAN RANDALL: Mr. Morgan's prefiled direct testimony, as corrected, will be read into the record as though given orally from the stand, and that's the public version. Confidential version will be held under seal.

MR. KNOWLES: Thank you, sir.

Q Mr. Morgan, did you also file three exhibits marked WJM-1 through WJM-3 with your prefiled direct testimony?

A (MORGAN) Yes, sir.

Q Do you have any changes, edits, or correction to these exhibits?

A (MORGAN) No. I do not.

MR. KNOWLES: Mr. Chairman, ORS originally filed WJM-1 and WJM-3 under seal with the Commission. The Company withdrew its claim of confidentiality regarding WJM-1, and ORS filed WJM-1 publicly on April 9. ORS would ask that

WJM-1 and WJM-2 be moved into the record in this case, and we would also ask that WJM-3 be moved into the record but that it remain under seal at this time.

CHAIRMAN RANDALL: Okay. Mr. Morgan's Exhibits WJM-1 and 2 will be entered as Exhibit Number 68. The confidential, WJM Number 3, will be entered as Exhibit Number 69 and held under seal.

MR. KNOWLES: Thank you, Mr. Chairman.

(WHEREUPON, Hearing Exhibit 68 was marked and received in evidence.)

(WHEREUPON, Hearing Exhibit 69 was marked and received in evidence.)

Q Mr. Morgan, are you the same Willie Morgan who prefiled six pages of surrebuttal testimony in Docket Number 2018-318-E on March 25th, 2019?

A (MORGAN) Yes. I am.

Q Do you have any changes, edits, or corrections to your prefiled surrebuttal testimony?

A (MORGAN) No. I do not.

Q And if I asked you today the same questions as those posed in your prefiled surrebuttal testimony, would your answers be the same?

A (MORGAN) Yes. They would.

Q Okay. Thank you.

MR. KNOWLES: And, Mr. Chairman, again, ORS had originally filed a public and a confidential version of Mr. Morgan's surrebuttal. In consultation with the Company, ORS understands that the surrebuttal testimony of Mr. Morgan may be made a part of the record in its entirety, without any redactions, so ORS would ask that the prefiled surrebuttal testimony of Mr. Morgan be read into the record as if given orally from the stand.

CHAIRMAN RANDALL: Mr. Morgan's prefiled surrebuttal testimony will be entered into the record as though given orally from the stand.

Q Mr. Morgan, have you prepared a summary of your testimony?

A (MORGAN) Yes. I did.

Q Okay. Well, let's proceed with that quickly, if we can. Mr. Morgan, what is the purpose of your testimony in this proceeding?

A (MORGAN) Mr. Chairman and other members of the Commission, the purpose of my testimony is to set forth the findings and recommendations resulting from ORS's examination of the Company's application

and to address certain pro forma adjustments.
Q What are those pro forma adjustments?
A (MORGAN) Adjust for reserve for end-of-life nuclear costs, amortize deferred cost balance related to SC AMI, normalize for storm costs, remove certain legal expenses, adjust for ongoing payment obligations with CertainTEED Gypsum NC, Inc., and adjust for nuclear materials and supplies inventory at power generation sites.
Q Would you please explain the Company's proposal to establish a reserve for end-of-life nuclear costs?
A (MORGAN) ORS recommends the Commission deny the Company's request for approximately $2.9 million for a reserve fund for its end-of-life nuclear costs. These costs are not known and measurable, and the date of retirement of the nuclear unit is uncertain.
Q And could you please explain the adjustment to amortize the deferred cost balance related to South Carolina AMI?
A (MORGAN) Commission Order Number 2018-553 granted the Company's petition for an accounting order to defer the incremental operating and maintenance expense and the depreciation expense associated with the Company's rollout of AMI. ORS recommends

the Company be allowed to amortize these costs over 15 years, which is the service life of the AMI meters.

Q And could you please explain the adjustment to normalize storm costs?

A (MORGAN) Company Adjustment Number 20 normalizes storm restoration expenses in the test year to a ten-year average, resulting in an increase in test-year expenses of approximately $7 million for South Carolina retail. Due to inflation -- excuse me -- due to fluctuations in annual storm restoration costs, ORS recommends eliminating the expenses in the highest and lowest years and to use an eight-year average expense level. The Company's adjustment adds an inflation adjustment to its ten-year storm expense average to determine its storm expense adjustment amount. ORS recommends the Commission reject the inflation adjustment, as it shifts all risk away from the Company and onto the customers. The inflation adjustment proposed by the Company is not known and measurable. It is speculative and is based on generalized data for the economy.

Q Could you briefly explain ORS's adjustment to legal expenses?

A (MORGAN) ORS adjusted non-allowable expenses to remove litigation expenses attributed to legal action related to coal ash. As detailed in ORS witness Wittliff direct testimony, the Company violated state and federal laws, which resulted in damages to the environment. The legal expenses are not related to providing adequate electrical services -- electrical service to customers, and customers derive no benefit from the expenditure. These legal costs should be the shareholders' responsibility, which is -- which, in turn, incentivizes the regulated utilities to operate in compliance with federal, state, and local laws.

Q Please explain ORS's position concerning payment obligations associated with the CertainTEED Gypsum NC, Incorporated case.

A (MORGAN) For the Company's request to adjust for ongoing payment obligation, inclusion of any payment obligation to CertainTEED stemming from this litigation as an allowable expense forces ratepayers to pay for DEP's failure to comply with the terms of an agreement. Furthermore, the ongoing payment obligations are not related to providing adequate electrical service to customers and the customers derive no benefit from the

expenditure.

(PURSUANT TO PREVIOUS INSTRUCTION, THE PREFILED DIRECT TESTIMONY, PUBLIC VERSION, INCLUDING CORRECTION/AMENDMENT, OF WILLIE J. MORGAN FOLLOWS.)

ELECTRONICALLY FILED - 2019 March 4 5:11 PM - SCPSC - Docket # 2018-318-E - Page 1 of 91

DIRECT TESTIMONY AND EXHIBITS OF

WILLIE J. MORGAN, P.E.

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-318-E

IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC

FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS

AND REQUEST FOR AN ACCOUNTING ORDER

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Willie J. Morgan and my business address is 1401 Main Street, Suite 900, Columbia, South Carolina 29201. I am employed by the South Carolina Office of Regulatory Staff ("ORS") as the Deputy Director of the Utility Rates Department.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of South Carolina in 1985 and a Master of Arts Degree in Management from Webster University in 2000. I am a licensed Professional Engineer registered in the State of South Carolina. I was employed by the South Carolina Department of Health and Environmental Control ("DHEC") as an Environmental Engineer Associate. Later, I was promoted to the position of Permitting Liaison where I assisted industries and the public with environmental permitting requirements in the State of South Carolina. This assistance included providing information about air quality, solid and hazardous waste management, and water and wastewater management requirements. I was employed by DHEC for

ELECTRONICALLY FILED - 2019 March 4 5:11 PM - SCPSC - Docket # 2018-318-E - Page 2 of 91

nineteen (19) years. In October 2004, I joined ORS as the Program Manager for the Water and Wastewater Department and was promoted to Deputy Director in 2015. Collectively, I have over thirty-three (33) years of regulatory compliance experience providing assistance and oversight for various types of regulated utilities.

Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes. I have testified on numerous occasions before the Commission regarding hearings concerning general rate cases and other proceedings.

Q. WHAT IS THE MISSION OF THE OFFICE OF REGULATORY STAFF?

A. ORS represents the public interest as defined by the South Carolina General Assembly as follows:

> The concerns of the using and consuming public with respect to public utility services, regardless of the class of customer, and preservation of continued investment in and maintenance of utility facilities so as to provide reliable and high-quality utility services.

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

A. The purpose of my testimony is to address certain areas of the ORS's examination of Duke Energy Progress, LLC's ("Company" or "DEP") application for adjustments in its electric rate schedules and tariffs and request for an accounting order under Docket No. 2018-318-E ("Application"). My testimony will specifically address the following adjustments to:

- Adjust reserve for end of life nuclear costs;
- Amortize deferred cost balance related to SC Advanced Metering Infrastructure technology ("AMI");
- Normalize for storm costs;

ELECTRONICALLY FILED - 2019 March 4 5:11 PM - SCPSC - Docket # 2018-318-E - Page 3 of 91

- Remove certain expenses (Legal Expenses);
- Adjust for ongoing payment obligation (Litigation/Dispute with CertainTEED Gypsum NC, Inc.); and
- Adjust for Materials and Supplies Inventory at Power Generation Sites.

These adjustments, more fully discussed below, were provided to the ORS Audit Department and are reflected in Audit Exhibit KLM-2 of ORS witness Major.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO ESTABLISH A RESERVE FOR END OF LIFE NUCLEAR COSTS.

A. The Company proposes to adjust depreciation and amortization expenses to establish a reserve for end of life nuclear costs not captured in its decommissioning studies. These costs include, but are not limited to, estimates for end of life nuclear fuel and parts inventory that are not currently known and measurable. The Company proposes to annually accrue approximately $2.9 million from South Carolina ratepayers to be placed in this reserve fund until its nuclear plants are decommissioned. The current operating licenses for the Company's nuclear units, issued by the Nuclear Regulatory Commission ("NRC"), will expire between ~~2033 and 2034~~ 2030 and 2046. Additionally, the Company can file for an additional license extension for its nuclear plants. Information provided by DEP for this rate case shows that the Company [redacted]. See Confidential Exhibit WJM-1, filed under seal.

Q. PLEASE EXPLAIN ORS'S RECOMMENDATION REGARDING DEP'S REQUESTED RESERVE FOR END OF LIFE NUCLEAR COSTS.

A. ORS recommends the Commission deny the Company's request of approximately $2.9 million for a reserve fund for its end of life nuclear costs. The reserve fund includes

ELECTRONICALLY FILED - 2019 March 4 5:11 PM - SCPSC - Docket # 2018-318-E - Page 4 of 91

estimates for end of life nuclear fuel and parts inventory that are not currently known and measurable. The date of retirement of the nuclear units is uncertain. It is not equitable for today's customers of DEP to pay for costs related to nuclear plant retirements that may or may not occur in the next fourteen years. The ORS adjustment to remove the requested reserve fund is reflected in ORS witness Major's Exhibit KLM-2 as Adjustment #15.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO AMORTIZE THE DEFERRED COST BALANCE RELATED TO SC AMI.

A. Commission Order No. 2018-553 granted the Company's petition for an accounting order to defer the incremental operating and maintenance expense and the depreciation expense associated with the Company's roll out of AMI. The Company proposes to adjust depreciation expense and income taxes for the amortization of deferred costs related to SC AMI. The accounting Order issued by the Commission approved the Company's requests for accounting treatment to defer the $1.4 million on a South Carolina Retail basis estimated through mid-2019 regarding the expense incurred once the AMI meters are installed, as well as the associated carrying costs on the investment and deferred costs at its weighted average cost of capital.

ORS recommends the Company be allowed to amortize these costs over fifteen (15) years, which is the service life of the AMI meters. The Company is proposing a 5-year amortization period; however, the Company provides no support for why a 5-year amortization period is appropriate. The amortization period proposed by the Company is not based on the service life of the asset. ORS's recommended fifteen (15) year amortization period is based on a 15-year life for AMI meters and the actual DEP

ELECTRONICALLY FILED - 2019 March 4 5:11 PM - SCPSC - Docket # 2018-318-E - Page 5 of 91

experience for electric meters. This recommendation is reflected in ORS witness Major's Exhibit KLM-2, Adjustment #19.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO NORMALIZE STORM COSTS.

A. Company Adjustment #20 normalizes storm restoration expenses in the Test Year to a 10-year average, resulting in an increase in test year expenses of approximately $7 million for South Carolina retail. Due to fluctuations in annual storm restoration costs, ORS recommends eliminating the expenses in the highest and lowest years and to use an eight-year average expense level. The ORS normalization adjustment is reflected in ORS witness Major's Exhibit KLM-2, Adjustment #20.

Q. BRIEFLY EXPLAIN ORS'S ADJUSTMENT TO LEGAL EXPENSES.

A. ORS adjusted non-allowable expenses to remove litigation expenses attributed to legal actions relating to coal ash. As detailed in ORS witness Wittliff's direct testimony, the Company violated state and federal laws which resulted in damages to the environment. Customers should not bear the burden of legal costs related to the Company's failure to operate its coal ash basins in accordance with state and federal rules and regulations. Inclusion of the legal costs as an allowable expense, forces ratepayers to pay for DEP's failure to comply with the law. Furthermore, the legal expenses are not related to providing adequate electrical service to customers, and customers derived no benefit from the expenditure. These legal costs should be the shareholders' responsibility which in turn incentivizes the regulated utilities to operate in compliance with federal, state and local laws. This recommendation is reflected in ORS witness Major's Exhibit KLM-2, Adjustment #36.

Q. BRIEFLY DESCRIBE THE CERTAINTEED GYPSUM, NC, INC. CASE.

ELECTRONICALLY FILED - 2019 March 4 5:11 PM - SCPSC - Docket # 2018-318-E - Page 6 of 91

A. In 2012 as part of an amended and restated Agreement, Progress Energy, DEP's predecessor, agreed to sell and deliver to CertainTEED and CertainTEED agreed to purchase and accept from Progress Energy at least 50,000 Net Dry Tons of Gypsum Filter Cake per month through 2029. CertainTEED pursued legal action against DEP due to DEP's failure to comply with the Agreement to provide a minimum amount of gypsum. On August 28, 2018, a Superior Court in North Carolina ruled in favor of CertainTEED. See Exhibit WJM-2. CertainTEED filed a Notice of Appeal and a Motion for Partial Stay Pending Appeal in the Litigation on September 27, 2018, and DEP filed a Notice of Appeal and a Motion for Limited Stay Pending Appeal on October 8, 2018. On October 1, 2018, DEP and CertainTEED entered into a confidential settlement agreement. See Confidential Exhibit WJM-3, filed under seal.

Q. PLEASE EXPLAIN ORS'S POSITION CONCERNING COST ASSOCIATED WITH THE LITIGATION INVOLVING CERTAINTEED GYPSUM NC, INC. CASE.

A. ORS determined the cost associated with the CertainTEED litigation should not be borne by the ratepayers. DEP's failure to meet its Agreement obligations provided no benefit to DEP's customers and the costs to litigate should be the shareholders responsibility. Inclusion of the legal costs and payments to CertainTEED as an allowable expense, forces ratepayers to pay for DEP's failure to comply with the terms of an Agreement. Furthermore, the legal expenses are not related to providing adequate electrical service to customers and the customers derived no benefit from the expenditure. This recommendation is reflected in ORS witness Major's Exhibit KLM-2, Adjustment #36.

ELECTRONICALLY FILED - 2019 March 4 5:11 PM - SCPSC - Docket # 2018-318-E - Page 7 of 91

Q. PLEASE EXPLAIN ORS'S POSITION CONCERNING COSTS ASSOCIATED WITH ANY PAYMENT OBLIGATIONS INVOLVING CERTAINTEED GYPSUM NC, INC. CASE.

A. Inclusion of any payment obligations to CertainTEED stemming from this litigation as an allowable expense, forces ratepayers to pay for DEP's failure to comply with the terms of an Agreement. Furthermore, the ongoing payment obligations are not related to providing adequate electrical service to customers and the customers derived no benefit from the expenditure. This recommendation is reflected in ORS witness Major's Exhibit KLM-2, Adjustment #38.

Q. PLEASE EXPLAIN THE MATERIALS AND SUPPLIES INVENTORY AT POWER GENERATION SITES.

A. Materials and Supplies ("M&S") Inventory consists of spare parts to maintain the reliability and serviceability of a generation plant. M&S Inventory can also include costs associated with future projects, as the Company needs to procure parts for a project before they are physically installed.

Q. PLEASE EXPLAIN THE ORS ADJUSTMENT TO M&S INVENTORY.

A. I reviewed DEP's records related to its nuclear plant M&S inventory. During my review, I discovered categories of inventory items designated in a "hold" status for over four (4) years. This excess nuclear plant M&S inventory cannot be used by DEP, and therefore, should not be recovered from DEP's customers and should be excluded from rate base. As a result, ORS recommends an adjustment of approximately $17.83 million (system) to the Company's M&S Inventory at its nuclear generation sites. The North Carolina Utility Commission approved a similar adjustment in the recent DEP general rate

ELECTRONICALLY FILED - 2019 March 4 5:11 PM - SCPSC - Docket # 2018-318-E - Page 8 of 91

proceeding by concluding that the recommended adjustment was "...just and reasonable to all parties considering all the evidence presented."[1] This recommendation is reflected in ORS witness Major's Exhibit KLM-2, Adjustment #39.

Q. PLEASE EXPLAIN YOUR REVIEW IN MORE DETAIL.

A. The Company provided information to ORS about its nuclear plant inventory at the end of the Test Year for all "hold" categories/classifications. The on "hold" material for the three DEP nuclear plants totaled $40,834,573. For reference, the approximately $40.8 million is based on average unit price ("AUP") of the inventory. DEP nuclear plant inventory records indicated $17,828,346 of M&S inventory in an "hold" status for four (4) years or more which is unsatisfactory.

Q. PLEASE DESCRIBE THE "HOLD" CATEGORIES OF M&S INVENTORY.

A. The Company categorizes M&S inventory into three (3) classifications of items considered unavailable for use at its nuclear plants. The categories are as follows:

- **Repair Hold:** Items in this category have been removed from service with the expectation of repair but are awaiting disposition – either by an external vendor or internal repair by Company personnel. This inventory is held in this status until a decision is made on whether the material can and should be repaired for use vs. purchasing new, and how to repair the item (internal or send to supplier).
- **QA Hold:** Items in this category have undergone a quality assurance inspection but a problem identified during receipt inspection requires resolution before releasing the hold.

[1] Reference: Testimony of Public Staff witness Dustin R. Metz, pages 13-18 from North Carolina Utilities Commission Docket No. E-2, Sub 1142. Also, see page 57 of North Carolina Utilities Commission Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase in Docket No. E-2, Sub 1142 dated February 23, 2019.

ELECTRONICALLY FILED - 2019 March 4 5:11 PM - SCPSC - Docket # 2018-318-E - Page 9 of 91

- **Stores Hold:** Items in this category include those with various problems, *i.e.* expired shelf life, problem at receipt, damaged/incorrect material found in the warehouse.
- **Engineering Change Hold**: Items in this category have been received but are awaiting the completion of an engineering change analysis/review before the material is released. The plant installed application has not been finalized and approved at time of receipt. Items in Engineering Change Hold can be in either QA Hold or Stores Hold.

These categories are commonly used in the electric industry for both nuclear and non-nuclear generation plants.

Q. WILL YOU UPDATE YOUR TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise or make new recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, become available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

(PURSUANT TO PREVIOUS INSTRUCTION, THE PREFILED DIRECT TESTIMONY, CONFIDENTIAL VERSION, INCLUDING CORRECTION/AMENDMENT, OF WILLIE J. MORGAN FOLLOWS.)

Prefiled Direct Testimony of
Willie J. Morgan

CONFIDENTIAL VERSION
(Including correction/amendment)
Maintained Under Seal

Pages 1321-1 ~ 1321-9
[Conf.] [Conf.]

(PURSUANT TO PREVIOUS INSTRUCTION, THE PREFILED SURREBUTTAL TESTIMONY OF WILLIE J. MORGAN FOLLOWS.)

SURREBUTTAL TESTIMONY OF

WILLIE J. MORGAN, P.E.

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-318-E

IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS AND REQUEST FOR AN ACCOUNTING ORDER

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Willie J. Morgan and my business address is 1401 Main Street, Suite 900, Columbia, South Carolina 29201. I am employed by the South Carolina Office of Regulatory Staff ("ORS") as the Deputy Director of the Utility Rates Department.

Q. DID YOU FILE DIRECT TESTIMONY AND EXHIBITS IN THIS PROCEEDING?

A. Yes. I filed direct testimony and three (3) exhibits with the Public Service Commission of South Carolina ("Commission") on March 4, 2019.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my surrebuttal testimony is to respond to certain portions of rebuttal testimony of Duke Energy Progress, LLC ("DEP" or "Company") witnesses Laura Bateman, Dr. Julius A. Wright, Kelvin Henderson, and Barbara A. Coppola. My surrebuttal testimony will specifically address the following adjustments to:

1) Adjust reserve for end of life nuclear costs;

2) Amortize deferred cost balance related to SC Advanced Metering Infrastructure technology ("AMI");

3) Normalize for storm costs;

4) Remove certain expenses (Legal Expenses);

5) Adjust for ongoing payment obligation (Litigation/Dispute with CertainTEED Gypsum NC, Inc.); and

6) Adjust for Materials and Supplies Inventory at Power Generation Sites.

Q. DOES THE REBUTTAL BY DEP WITNESS HENDERSON CHANGE ORS'S POSITION ABOUT THE COMPANY'S REQUEST TO ESTABLISH A RESERVE FOR END OF LIFE NUCLEAR COSTS?

A. No. The Company desires to establish a reserve fund for end of life nuclear costs not captured in its decommissioning studies using estimated costs that are not tied to a specific time for the retirement of its nuclear fleet. The Company's request is premature because both the amount of the costs and timeframe for the nuclear fleet retirement are uncertain. To my knowledge, the Nuclear Regulatory Commission ("NRC") has yet to deny an applicant's request for a renewal of their license. In fact, the Company has already experienced a successful 20-year extension on its license at its Brunswick Nuclear Plant (Units 1 and 2) and Robinson Nuclear Plant (Unit 1) and other locations at one of its affiliate companies. The Company attempts to make its projections based on limited information and many assumptions, making the costs both unknown and not measurable within a degree of reasonable certainty. ORS recommends the Commission reject the Company's request to require customers to pay for a reserve fund that is based on events

that may or may not occur in the manner being projected by DEP and costs that are estimated.

Q. PLEASE EXPLAIN WHY ORS'S ADJUSTMENTS TO AMORTIZE THE DEFERRED COST BALANCES RELATED TO SC AMI IS APPROPRIATE.

A. It is important to note that the Company provided no justification for the amortization period the Company recommends for this deferred cost balance. And, absent the approval of an accounting order establishing the regulatory asset, the Company would not be able to recover all the costs requested because a portion of this deferral balance was incurred outside of the Test Year.

It is within this Commission's discretion to set the amortization period over which a deferral account will be recovered. It is reasonable to base the amortization period upon the life of an underlying asset because that is the period which it is anticipated to benefit the customer. ORS's recommendation for amortization period for this deferred balance is consistent with the service life of the associated asset.

ORS recommended amortization period remains as follows:

Adjustment #	Adjustment	ORS Amortization Period
19	SC AMI	15 years

Q. PLEASE EXPLAIN WHY ORS DISAGREES WITH DEP WITNESS BATEMAN'S ADJUSTMENT TO NORMALIZE STORM COSTS.

A. Company witness Bateman in her rebuttal testimony does not oppose ORS' recommended method for determining the amount of the storm restoration expense adjustment in the Test Year. However, the Company's adjustment adds an inflation

adjustment to determine its ten-year average storm expense adjustment amount. The Company claims an inflation adjustment is warranted to mitigate the impact of regulatory lag. ORS recommends the Commission reject the inflation adjustment as it shifts all risk away from the Company and onto the customers. The inflation adjustment proposed by the Company is not known and measurable, speculative, and is based on generalized data for the economy.

Q. DO YOU AGREE WITH COMPANY WITNESS COPPOLA'S CHARACTERIZATION OF YOUR POSITION CONCERNING ADJUSTMENT #38 FOR ONGOING PAYMENT OBLIGATION WITH CERTAINTEED GYPSUM NC, INC. ("CERTAINTEED")?

A. No. Company witness Coppola mischaracterized ORS's position for the Company's on-going payment obligation in Adjustment #38. ORS agrees that the sale of a coal-ash byproduct to companies like CertainTEED may benefit customers. This may be true when compared to the cost for other disposal options. Company witness Coppola's rebuttal testimony did not acknowledge the Company's required on-going payment obligation is the result of a settlement agreement arising out of litigation with CertainTEED. The vendor, CertainTEED, initiated legal action against DEP because the Company failed to provide CertainTEED with the required contract amount of at least 50,000 net dry tons of gypsum filter cake per month through 2029. A settlement was eventually reached between DEP and CertainTEED following a North Carolina Superior Court decision ruling that DEP breached its contract with CertainTEED. Under the settlement agreement, DEP is required to make payments to CertainTEED which are recorded as the on-going payment obligation that DEP requests to recover from customers.

Company witness Coppola does not provide an explanation of the services or benefits DEP customers receive in exchange for these payments made to its vendor. It is ORS's recommendation that DEP customers should not be required to pay for an on-going payment obligation to CertainTEED that was triggered by DEP's breach of contract.

Q. WHAT IS ORS'S POSITION RELATED TO LITIGATION EXPENSES INCURRED CONCERNING THE CERTAINTEED CONTRACT DISPUTE?

A. As a result of DEP's breach of contract, DEP incurred litigation costs in the matter with CertainTEED. The Company was not successful in its defense of the litigation. As the trial court found, "DEP has failed to carry its burden of proof on its defenses." (Exhibit WJM-2 at p. 80 ¶237.) ORS recommends DEP customers be held harmless for all litigation expenses related to the legal action brought by CertainTEED. DEP was found to have failed to comply with its agreement by not supplying adequate amounts of gypsum and the North Carolina Superior Court issued an order to this effect. It was only after the adverse decision of the court that a settlement of the dispute was reached. Further discussion about litigation costs is discussed by ORS witness Steven Hamm.

Q. PLEASE EXPLAIN ORS'S UPDATED RECOMMENDATION FOR THE MATERIALS AND SUPPLIES INVENTORY AT POWER GENERATION SITES.

A. Upon further review of Company witness Henderson's rebuttal testimony, ORS updates its recommendation related to Materials and Supplies ("M&S") Inventory held for over four (4) years and designated in a "hold" status. M&S Inventory designated as "Engineering Change Hold" items may be used in the future for certain plant projects. Therefore, I update the ORS adjustment to approximately $6.3 million (system) for the Company's M&S Inventory at its nuclear generation sites.

Q. WILL YOU UPDATE YOUR SURREBUTTAL TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, become available.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

THE EXAMINATION BY MR. KNOWLES CONTINUES.

Q Okay. Thank you. Mr. Morgan, is it your understanding that the Company and ORS have entered into a stipulation that covers several points in your testimony?

A (MORGAN) Yes. I do.

Q Okay. Yeah.

MR. KNOWLES: Mr. Chairman, I -- I would apologize. That's my oversight. That -- that has been e-filed, we understand, and, so we -- we could've shortened that, and I -- I apologize, because I know your time is valuable. Thank you, Mr. Morgan.

WITNESS MORGAN: Thank you.

MR. KNOWLES: The panel is available for cross-examination and questions from the Commission and parties.

CHAIRMAN RANDALL: Thank you. Okay. Ms. Ferguson, Mr. Neal, cross? Mr. Guild?

MR. GUILD: Gentleman, thank you for your testimony. No questions, Mr. Chairman.

CHAIRMAN RANDALL: Thank you. Mr. Elliott?

MR. ELLIOTT: Please, Mr. Chairman.

CROSS-EXAMINATION

BY MR. ELLIOTT:

Q Mr. Morgan, indulge me. I've got a few questions for you.
A (MORGAN) Okay.
Q I don't think you'll need the ELMO for this, Mr. Morgan, but I thought it was pretty impressive, and, so I wanted to put it up for everybody to see. All right. Mr. Morgan, you are, as I understand it, a licensed professional engineer, correct?
A (MORGAN) Yes, sir.
Q And, prior to your employment at the ORS, you were employed by DHEC as an environmental engineer associate, correct?
A (MORGAN) That was my initial employment status, and -- and there were a -- a promotion along the way.
Q Yes. And you were promoted to the position of permitting liaison, where you assisted industries and the public with environmental permitting requirements in South Carolina, correct?
A (MORGAN) Yes, sir.
Q And your assistance in this regard included providing information about air quality, solid and hazardous waste management, and water and wastewater management requirements; is that correct?

A (MORGAN) Yes, sir.
Q And you were employed by DHEC for about 19 years, correct?
A (MORGAN) Yes, sir.
Q Now, I want to draw your attention, if I may, to this Robinson plant coal ash pond. You are aware that Progress, in this case, is seeking to recover ultimately about 178/179 million dollars from its ratepayers for the coal ash remediation from that pond? You're generally aware of that, are you not, sir?
A (MORGAN) Yes, sir.
Q And they're seeking some recovery of some amount -- $11 million perhaps in this case -- I don't have that number -- but they're seeking recovery here, correct?
A (MORGAN) Yes, sir.
Q And you understand that it is the Company's position and you understand that it is the ORS position, that because the -- Duke Progress and -- entered into an agreement with -- a consent agreement with DHEC, that it is by virtue of that agreement with the regulator that -- that recovery of those costs is justified? You understand that generally, don't you, sir?

A (MORGAN) Yes, sir.
Q All right. And what I want to do this morning is just sort of pick your brain a little bit about your experience at -- at DHEC and how it might be -- help inform the Commission. Now, as I understand it, in -- in the -- in the hazardous waste area, it -- hazardous waste sites must be permitted and regulated by DHEC. That's correct, isn't it?
A (MORGAN) Yes. It's permitted under Subtitle C, "Landfill Requirements."
Q All right. And -- and, as -- as are, I guess, all landfills, hazardous or otherwise, correct?
A (MORGAN) Well, the hazardous under the Subtitle C and then the nonhazardous as what we've been discussing relative to coal ash disposal, Subtitle D.
Q All right. And so this pond was regulated under -- under the non-hazardous Subtitle D. Now, as a part of DHEC's regulatory process, DHEC would make regular inspections of -- of this coal ash pond and -- and any landfill, correct?
A (MORGAN) That -- that is -- that is the procedure, yes, sir.
Q And you -- you made -- in -- in -- in your

experience at DHEC, you actually made inspections of landfills, did you not?

A (MORGAN) On a regular basis.

Q And you made those -- the regular basis was a quarterly basis? Those inspections were made quarterly, were they not?

A (MORGAN) For some, and we had one, of course, the hazardous waste landfill, we inspected that one more frequent.

Q Good. And, as a part of your inspection, you would pay careful attention to determine whether or not the -- the landfill in question met or exceeded regulatory requirements, wouldn't you, sir?

A (MORGAN) Yes. Yes, sir.

Q All right. And, in inspecting these landfills, you would be looking for -- you would be looking at whether or not the -- the -- the area was appropriately covered by soil or -- or -- and properly grassed, correct?

A (MORGAN) Yes, sir.

Q And you would be looking to determine whether the landfill operator, in this case Progress, met its obligation to control dust, odors, litter, vectors, fires, and open burning, correct?

A (MORGAN) Yes, sir.

Q And -- and, in making an inspection of this Robinson plant landfill, you would, on your quarterly inspections, inspect the property to make sure that the site was maintained and operated in a manner to protect the groundwater and surface water quality at the location of the coal ash pond, correct?

A (MORGAN) That would be part of the evaluation process, yes, sir.

Q And -- and, in making your inspections, you would -- you would -- you had a form that was governed by a regulation -- a DHEC regulation that you would have to fill out on every occasion, correct?

A (MORGAN) Yes, sir. The form was -- was generated based on -- on the regulations, yes, sir.

Q Very fine. Indulge me a moment.

MR. ELLIOTT: Mr. Chairman, I'd like to mark an exhibit for identification, please.

CHAIRMAN RANDALL: Mark it as Number 70.

MR. ELLIOTT: I -- I don't have copies for my friends in the middle.

CHAIRMAN RANDALL: How about your friends up here this way?

MR. ELLIOTT: Well, I'll -- you can have this

one when I'm through. I -- I just --
CHAIRMAN RANDALL: Yeah.
MR. ELLIOTT: -- understood we needed one copy to be put into evidence, Mr. Chairman. I -- I hope you'd indulge me. Mr. Chairman, ORS has been very kind.
(WHEREUPON, Hearing Exhibit 70 was marked in evidence.)

Q All right. Now, Mr. Morgan, you're younger than I am, and I'm going to assume that your eyes are better, but I show -- I've -- I've zoomed in a little bit to show you this document, which is labeled "Structural Fill Inspection Form, Regulation 61-107.19, Part II." Do you see that language?

A (MORGAN) Yes, sir.

Q And I did give you a moment, prior to your testimony, to inspect this form. And can you identify this as a DHEC form that is promulgated for the purpose of recording the results of an inspection at landfills such as the one at Robinson, correct?

A (MORGAN) Well, the form was generated to help and assist the inspector with the review of the facility to ensure compliance with the -- the

regulation.

Q Excellent. Thank you for the help. And, in this particular case, the structural fill inspection form, the official DHEC form, is for the HB Robinson plant, correct?

A (MORGAN) Yes, sir.

Q And it shows a date of 6/9/15 -- June 9, '15, does it not?

A (MORGAN) Yes, sir.

Q And, of course, it identifies the county and the permit number, correct?

A (MORGAN) Yes, sir.

Q And the reason for the inspection is "Routine," correct?

A (MORGAN) Yes, sir.

Q And, as I understand your testimony, the -- what is routine in this case is a quarterly inspection, and, so this would be the quarterly inspection for the time in question, correct?

A (MORGAN) Yes, sir. I mean, I would add, though, that, from time to time, if there are issues that are identified for whatever reason -- someone calling us to complain or whatever may dictate a need for an inspector to go out to the site -- one would be generated then as well.

Q All right. Good. Thank you. And that's helpful. Now, I've zoomed out a little bit and I'm going to zoom back in, but there's a legend in what is now the middle of the screen on the -- on the ELMO, and I would draw your attention to Number 1. The language is, "Meets or exceeds regulatory requirements." Do you see that language?

A (MORGAN) Yes, sir.

Q And so it's fair to say that, if a reader -- if the inspector found that the -- the landfill at the time met or exceeded the regulatory requirements that he would put a "1" there, correct?

A (MORGAN) Yes, sir.

Q Or, in this case, I think, probably a she. Now, I've -- I've -- I've just blown it up so we can see the -- see the parts, but the first part, "Facility Entrance Area Fill Area, Regulation 61-107.19, Part II." You see that language?

A (MORGAN) Yes, sir.

Q And so there's sort of a laundry list there, and I won't read every one, but there are certain basic matters that the inspector needs to observe at the outset, such as, "Was there -- there an attendant present?" and, "Was the area properly staged?" and so forth. Do you see that?

A (MORGAN) Yes, sir.
Q And there's also some language here, "Waste reduced in size to less than 1 cubic yard in place," and I don't fully understand that, but it was compliant, right? It says yes? Circled --
A (MORGAN) Yes.
Q -- "Y" for yes?
A (MORGAN) Yes, sir.
Q And there's a Question Number 8, "Monthly cover, Regulation 61-107.19, Part II E7." The -- the -- the -- the point to be observed is, "Cover applied monthly with at least 6 inches of soils or other Department approved material?" Do you see that?
A (MORGAN) Yes, sir.
Q And the inspector found that it was properly covered, correct?
A (MORGAN) Yes, sir.
Q And the inspector found that the condition of cover on inactive or closed areas met or exceeded the regulatory requirements, correct?
A (MORGAN) Yes, sir.
Q Because there's a "1" there by -- in the blank by 9, and -- and, when you look at the legend above, it's -- it reads, "Meets or exceeds regulatory requirements," correct?

A (MORGAN) Yes, sir.
Q Mr. ELMO is not going to cooperate.
MR. ELLIOTT: Now, indulge me, Mr. Chairman.
Q Now, the next section, beginning with Number 10 -- and this is the one I really want to draw your attention to -- is labeled "Environmental Protection, Regulation 61-107.19, Part II E." Do you see that language?
A (MORGAN) Yes, sir.
Q And -- and Number 10 -- the matter to be considered by the inspector under Number 10 is, "Control of dust, odors, litter, vectors, and fire/open burning," and the landfill on this occasion met or exceeded the regulatory requirements, correct?
A (MORGAN) That's what the inspector recorded at -- for that -- that -- that time. It's --
Q As was -- as -- as was her duty under the regulation and under the terms of this inspection report, correct?
A (MORGAN) Yes, sir.
Q She had -- she had to record the -- the -- the correct observation, correct?
A (MORGAN) Yes, sir.
Q Thank you. Now, Number 11, "Site maintained/operated in a manner to protect

groundwater and surface water quality?" Do you see that language?

A (MORGAN) Yes, sir.

Q And the inspector found that, yes, the site was maintained and operated in a manner to protect the groundwater and the surface water quality, correct?

A (MORGAN) Yes, sir.

Q And then, last, there's a list, Number 12 through 15, of "Closure of Entire Structural Fill Area" under Regulation 61-107.19, and there are a number of questions about the -- the soil cover and the slopes and so forth. And what the inspector found was that -- that the -- the -- the cover and the slopes met or exceeded DHEC's requirements for the operation and maintenance of -- of that coal ash pond, correct?

A (MORGAN) Yes, sir.

Q And then the -- the inspector would make an observation as to who was present. We'll see from this form that Ms. Watson was the inspector, Mr. Gilbert was the Duke Progress representative, and she makes a note that apparently the last date waste was added was before 3/15, and I don't know whether that's March 15 or if that's -- March of 2015 or 3/15 of -- of -- of this year. And then

probably the same thing. And then some reference to a final deed report. Do you see that language?

A (MORGAN) Yes, sir.

Q And then it's signed by -- it's signed by the inspector, Ms. Watson. Do you see that?

A (MORGAN) Yes, sir.

Q All right.

MR. ELLIOTT: Mr. Chairman, I'd move this into evidence at this time.

CHAIRMAN RANDALL: It'll be entered as Number 70.

MR. ELLIOTT: Seventy. Thank you, sir.

(WHEREUPON, Hearing Exhibit 70 was received in evidence.)

Q Now, Mr. Morgan, as I understand it, with respect to landfill violations, as with -- and -- and what I'm more familiar with, and you and I have worked on over the years -- violations of NPDES permits, the -- if an inspection, whether it's self-reported in the case of the -- of the water and sewer companies or whether it's an inspection by, say, Ms. Watson in this case of this landfill -- if the inspection shows a violation of -- of -- of regulation -- a DHEC regulation, DHEC will notify the Company and give it notice of the violation,

correct?
A (MORGAN) Yes, sir.
Q And -- and, when you and I do business on the water and sewer side, it's -- we shorten it to "NOV," correct?
A (MORGAN) Yes, sir. If -- if it's of that level. Sometimes, you know, it could be simply a warning letter, and that's not -- that's those violations that are not considered as serious.
Q Yes, sir. And if there's a serious violation, then -- with respect to the landfill, as with the water and sewer regulation, DHEC will give a notice of violation and -- and require the regulated utility to come into the DHEC offices for a conference to determine whether a violation occurred, and if so, what the penalty should be, correct?
A (MORGAN) Yeah. Sometimes, though, it could simply be a requirement to provide a response as opposed to actually showing up for an enforcement conference.
Q All right, sir. And I understand that. And -- and, on behalf of all lawyers representing utilities everywhere, we always hope it's the letter and not --
A (MORGAN) Uh-huh.

Q -- the conference. But if it's serious enough, the -- the utility, in this case Progress, would -- would be called in for a conference, correct?

A (MORGAN) Yes, sir.

Q And the result of these conferences, in my experience, is almost universally one where the utility agrees that it is a violation of its permit and seeks to mitigate whatever penalty DHEC seeks to impose. Is that not your observation as well?

A (MORGAN) Those are the type you would hope for, and if it's something that led to the national enforcement action, you -- you hate to have to deal with a -- an administrative order, which is where the Company has failed to cooperate in addressing the matter.

Q Right, right. And -- and, so, ultimately, if there's a notice of a violation, it's substantial, there's a status conference, there will be a consent order that will result, correct?

A (MORGAN) Typically, yes, sir.

Q And that consent order --

A (MORGAN) Or -- or a compliance order.

Q All right, sir. And that consent or compliance order will set out certain findings which would include any violation of the utility's permit,

correct?
A (MORGAN) Yes, sir.
Q And, typically, although not always -- but typically, a violation of the permit will result in a fine by DHEC, correct?
A (MORGAN) A fine or a contingency penalty, whereas, if the Company addresses the matter in a timely manner in accordance with that order, the penalty will not be assessed. And if they do not, then the penalty is automatically triggered because they failed to comply with the order.
Q Right. So the document would set out a penalty?
A (MORGAN) Yes, sir.
Q And -- and, you know, if you beg for mercy strong enough, you might get put on probation?
A (MORGAN) Right.
Q Let me show you Hearing Exhibit 42, if I may. I'm going to put it on the ELMO. It is labeled "In re: Duke Energy Progress, Inc., HB Robinson Steam Electric Plant, Darlington County, Consent Agreement 15-23-HW." Have I read that correctly?
A (MORGAN) Yes, sir.
Q And I think you've had an opportunity to at least review this consent agreement as a part of your duties at ORS, correct?

A (MORGAN) Yes, sir. As a part of one of our witness testimony in terms of their exhibit.
Q All right, sir. And if I were to draw your attention to the findings of fact on Pages 2 and 3 of the document -- I'll just set it up here for demonstrative purposes -- would I be correct in saying that there are no findings of fact in this consent agreement demonstrating that Progress violated any of the terms of its permit for its landfill pond at -- at the Robinson plant?
A (MORGAN) When I read it, I did not see any -- any such --
Q All right, sir.
A (MORGAN) -- language.
Q And -- and -- and if it makes you feel better, the two preceding witnesses have not been able to find a finding in the order, either.

And I would then ask you, if you, in your review of the order, were able to ascertain whether there was a fine or a penalty assessed against Progress as a part of this Consent Agreement 15-23-820 -- -HW.

A (MORGAN) No, sir. I did not see that.
Q Last, I want to show you Paragraph 16 of the consent agreement we've been discussing, which is

found on Page 10, and I'm going to -- I'm going to ask you this -- and -- and you feel free to read whatever of this document you'd like to read. I would -- would remind you it's the last morning of the last day of the hearing, so use your discretion, but if you look about halfway down that paragraph, I -- I see this language -- I'm going to read it and ask you if I've read it correctly -- "Once the Department has approved the final report, the Department will provide Duke Energy a written approval of completion that provides covenant not to sue to Duke Energy for the response actions specifically covered in this consent agreement approved by the Department and completed in accordance with the approved work plans and reports." Have I read that language correctly?

A (MORGAN) Yes, sir.

Q In your experience at -- at DHEC for the 19 years or so you worked at DHEC, and from your observations in the last 15 years or so at the ORS, would you agree with me that it is -- it is unusual, if not rare, that a consent agreement or order from DHEC will -- will include a covenant where DHEC agrees not to sue the regulated entity?

A (MORGAN) I haven't -- I have not seen that in any

of the orders that I've reviewed or were a part of formulating while I was at DHEC or even since I've been here at ORS. I have not seen that -- that language.

Q Very fine. Thank you so much, Mr. Morgan. Mr. Hamm, I just have a -- kind of a short line for you, if I may.

A (HAMM) "Short" is the operative word.

Q Yes, sir. Now, you are testifying in your capacity as special counsel and senior advisor in the legal department at the ORS, correct?

A (HAMM) Yes, sir.

Q And, in your capacity as special counsel and senior advisor, is it fair to say that you are generally familiar with the issues raised by the Office of Regulatory Staff in this docket?

A (HAMM) Yes, sir.

Q And, as a part of that, you are aware that an issue has developed over a certain O&M expense associated with the Customer Connect project, are you not?

MR. ELLERBE: Mr. Chairman, we have an objection. I am fully aware that we have open -- we have a tradition of open cross-examination in proceedings before this Commission, and I'm also aware that we allow

friendly cross-examination: cross-examination by parties that are aligned. I've engaged in such cross-examination myself in the past.

However, the Commission has an obligation to conduct the hearing in a way that allows all parties to have fair notice of the -- of the allegations and the evidence that they're going to be confronted with and to respond to it. That arises from the due process clause of the US Constitution and Article I, Section 22 of the South Carolina Constitution. We've talked about that earlier in this proceeding -- that provision. This Commission has adopted rules requiring the prefiling of testimony in order to carry out that, and that lets people know, "This is what we're -- this witness is going to testify about," and you then respond, and we have rebuttal and surrebuttal. Mr. Hamm was a surrebuttal -- surrebuttal witness testifying on certain limited subjects, and he's done that. Mr. Elliott is now proposing to ask him to offer expert opinions on subjects beyond the scope of his surrebuttal testimony, and it appears that this is preplanned friendly cross-

examination coordinated in advance. I haven't -- I got up quickly so that -- to try to prevent it and try to put our objection on the record, but we saw something similar on Monday when the ORS attorney cross-examined the Energy Users witness, Kevin O'Donnell. There was a question asked, and Mr. O'Donnell just happened to have the calculations in front of him on a piece of paper, and Mr. O'Donnell ended up testifying on friendly cross-examination to subjects well beyond the scope of his prefiled testimony.

So we think that -- that, on this cross-examination of a surrebuttal witness under these circumstances by a party aligned with the ORS, the cross-examination should be limited to the subjects that Mr. Hamm covered in his surrebuttal testimony, and he should not be allowed to go beyond that in order for the Commission to enforce its own rules that allow for a -- for fair hearings, so -- thank you very much.

MR. ELLIOTT: Mr. Chairman, it's open cross. I have brief cross-examination for this witness. The ultimate question I have for Mr.

Hamm deals squarely with the CertainTEED contract dispute, and I just -- I need about two questions to set that up, and then I'm going to ask Mr. Hamm the applicability of the -- of -- of this -- the substance of his testimony, the -- the -- the contract action for CertainTEED to these other issues in the case. I think it's fair, and -- and it will be brief, and Mr. Ellerbe should not be surprised.

CHAIRMAN RANDALL: Okay, okay. We'll allow you these -- these questions -- these two questions, and -- but we need to keep it very narrow and with what -- you know, with what he's -- he's proposed --

MR. ELLIOTT: You will see --

CHAIRMAN RANDALL: -- Mr. Elliott.

MR. ELLIOTT: You will see that it will be so.

THE EXAMINATION BY MR. ELLIOTT CONTINUES.

Q All right. So, Mr. Hamm, you are aware that Duke witness Retha Hunsicker testified in this docket in support of the recovery of certain O&M costs associated with the Customer Connect program, are you not?

A (HAMM) Yes, sir.

Q And I would put on the ELMO her summary, or a portion of it, and I will ask you -- this is strictly off her -- it's just a copy of her summary, and I will ask you if Ms. Hunsicker did not testify as follows: "The Company's calculation of incremental O&M expense for 2019 and 2020 clearly meet the known and measurable standard because, one, the Company has entered into fixed contracts with multiple vendors to develop the program; two, the contracts contain provisions requiring the Company to provide specified levels of internal labor to support the work; and, three, the fixed contracts contain specified price terms." Have I read that correctly?

A (HAMM) Yes, sir.

Q And so my question to you is, Mr. Hamm, you would agree with me that -- that contracts, no matter how binding, are not necessarily known and measurable, are they?

A (HAMM) Well, contracts are binding, and depending on the terms of the contract, you may -- it may not be known and measurable, because that's a -- depends on the timing of the contract.

Q All right. And you would agree with me that the -- while the Company might've thought the CertainTEED

contract was known and measurable, it turned out to be anything but known and measurable, didn't it?

A (HAMM) Yes. Because DEP was unable to convince the judge in North Carolina that its -- its view of that contract was supported by the language and the court rejected that position.

Q And which is not disputed by the Company at this point now because they've settled, correct?

A (HAMM) Well, the -- yes. They settled, but it's a final judgment, and there was no -- no appeal, and there's -- the settlement does not change the fact that there's a court order in North Carolina issued in August of 20'8 regarding the dispute between Duke and the CertainTEED subsidiary.

Q And so the bottom line is that this contract ended up costing Duke Progress about $90 million, if I understand your testimony correct. Am I right?

A (HAMM) It cost $90 million. They're seeking to have customers pay for their failure to understand their own contract, which ORS is contesting.

Q Very fine.

MR. ELLIOTT: Thank you, Mr. Chairman. I have no further questions.

CHAIRMAN RANDALL: Thank you. Nucor, Mr. Smith? Mr. Lavanga?

MR. SMITH: No questions, Mr. Chairman.

CHAIRMAN RANDALL: Company?

MR. ELLERBE: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. ELLERBE:

Q Good morning, gentlemen. Mr. Morgan, just to be clear after the questions Mr. Elliott asked you about Robinson remediation expenses, ORS is supporting recovery in rates by DEP of the remediation costs associated with the Robinson coal ash cleanup, correct?

A (MORGAN) Yes, sir.

Q And the ORS position is that that was pursuant to an agreement with DHEC and a state policy, and therefore, South Carolina ratepayers should -- should pay those costs?

A (MORGAN) Yes, sir.

Q And is -- are you aware that the remediation, the excavation and -- of the coal ash ponds at the Robinson plant is consistent with what's being done at the other coal ash ponds in -- throughout the state of South Carolina?

A (MORGAN) There are some similarities and there are some differences.

Q But the Santee -- Santee Cooper ended up excavating

all of its ponds, correct?
A (MORGAN) I'm not certain of all of that, but I understand that they were in the process of doing some of that.
Q And SCE&G also?
A (MORGAN) Yes, sir. I'm aware they've done some of that.
Q Okay. Thank you, sir. Mr. Hamm, just a few questions for you, sir. You talked about the Company's responses, and you attached to your surrebuttal testimony the Company's responses to the ORS AIRs, Audit Information Request Number 43. Are you aware of the supplemental responses that the Company filed on April 3rd and April 7th to those requests by ORS?
A (HAMM) Yes, sir. I am.
Q Have you reviewed those, sir?
A (HAMM) Yes, sir.
Q Does this look like the information? Excuse me.
A (HAMM) Yeah. That's similar to the stack of documents.
Q Yeah.
A (HAMM) I am going to take it on -- on faith and -- and I -- and I mean this seriously -- respect that what you're representing is, in fact, what you

placed on -- next to the court reporter.

MR. ELLERBE: Yes. We -- we'd like the record to -- we'd like to introduce the Company's response -- supplemental responses to -- now, I walked away -- the supplemental response to Number 43-4 -- Audit Request 43-4, Audit Request 43-2, and Audit Request 43-5, and these supplemental responses were provided to the ORS on April 3rd for the response to 43-4, and on April 7 for the response to 43-2 and 43-5.

MR. GUILD: Mr. Chairman, Sierra Club objects to the receipt of these documents into evidence. They're untimely. The record in this case is determined by --

CHAIRMAN RANDALL: Get to -- let's get a microphone.

MR. GUILD: I'm sorry. Mr. Chairman? Mr. Chairman? Hello.

Mr. Chairman, Sierra Club would reject to receipt of these materials in evidence. You know, the record in this case has to close at some point. I understand the point of ORS's testimony to reflect the submissions, or lack thereof by the Company, at the time they were

due. Now, we honored a -- a pre-hearing schedule that required the prefiling of direct and rebuttal testimony and the timely filing of the exhibits supporting that testimony all pursuant to the same logic that Mr. Ellerbe advanced in his last objection that was rejected by the Commission, and that is that there's a due process element that works both ways in this case. And you should judge the adequacy of the Company's evidentiary submissions based on the evidence that they timely submitted in accordance with those pre-hearing -- orderly pre-hearing schedule to supplement their showing by April filings, and that's what I understand Mr. Ellerbe to submit with regard to the massive stack of documents sitting before the court reporter, which has not been served on my client or any other parties that I know of, would simply violate basic principles of due process that the Company has insisted the Commission follow. So the question is, you should judge the evidence at the time it was required to be submitted, not bootstrapped at the eleventh-and-a-half hour, because this is the last day

-- the last morning of the last day of the hearing. And we simply are in no position to intelligently respond to this, nor, I submit, should ORS be responsible for submitting -- for responding to it at this late hour, either. So we object on the grounds that these submissions are untimely and that it would deny my client due process for the Commission to receive them at this hour.

MR. ELLERBE: Mr. Chairman, probably half the exhibits in this record are hearings that were -- are exhibits that were introduced at this hearing on cross-examination, and Mr. Hamm's testimony says -- you know, makes a point of the inadequacy of our response, and we simply want the Commission to know that a supplemental response was submitted, and we think that it ought to be included as part of the record in the case, and -- and could be given the weight that the Commission determines is appropriate.

CHAIRMAN RANDALL: Okay. I'm going to overrule the objection. We're going to accept these and -- and assign the appropriate weight to it. We're going to accept it into the

record.

(WHEREUPON, Hearing Exhibit 71 was marked and received in evidence.)

MR. ELLERBE: Thank you, Mr. Chairman. Gentlemen, no further questions.

CHAIRMAN RANDALL: Commissioners?

MR. ELLERBE: Mr. Chairman?

CHAIRMAN RANDALL: Sir?

MR. ELLERBE: What hearing exhibit was that?

CHAIRMAN RANDALL: Seventy-one.

MR. ELLERBE: Thank you.

CHAIRMAN RANDALL: Commissioner Belser? It's time for commissioner questions --

COMMISSIONER BELSER: Uh-huh.

CHAIRMAN RANDALL: -- or you can ask -- you can ask Mr. Ellerbe.

COMMISSIONER BELSER: Mr. Ellerbe, can you tell us again what that hearing exhibit is -- what comprises that exhibit, please?

MR. ELLERBE: The supplemental response to Audit Request 43-4. The request was, "Could you please elaborate on potential insurance recovery for coal ash included in the explanations for legal expenditures?"

And there's a response -- several-page

response and exhibit. The supplemental response to the forty-third audit request, 43-2, is, "Of those coal ash litigation expenses identified, please identify what account they are booked to and the SC retail portion that was included in the Company's application for recovery in rates in this docket."

And this is a supplemental response that was -- previously, a spreadsheet was provided. This is a supplemental response with additional information -- backup information that was provided.

COMMISSIONER BELSER: So it's -- they're all related to supplemental responses to litigation expenses?

MR. ELLERBE: Yes, ma'am.

COMMISSIONER BELSER: Thank you.

MR. ELLERBE: Those are the -- they're supplemental responses to the -- to the -- to the -- the discovery request that Mr. Hamm referenced in his surrebuttal testimony.

COMMISSIONER BELSER: Thank you.

CHAIRMAN RANDALL: Okay. Yes, sir?

MR. GUILD: Mr. Chairman, just -- Mr. Chairman, just to make the record complete,

I'd also assert a lack of foundation and a hearsay objection. Mr. Ellerbe didn't even show the documents to a witness, let alone offer a witness who could establish a proper foundation for these documents or one who could establish that they aren't hearsay. I mean, it's simply a stack of paper that it would be highly improper for this Commission to rely on those records, under these circumstances, to undermine an ORS or other party's contention in this case. They've offered no witness to support these documents. I can't cross-examine a set of documents that haven't been provided. So I'd object in addition and move to strike on the grounds that these documents lack a foundation and represent hearsay.

MR. ELLERBE: Mr. Hamm did acknowledge that ORS had received these discovery requests -- discovery responses and that he had reviewed them. This is the time -- exactly the time for a document that's come into evidence throughout this case in -- both in part of the prefiled direct and a great deal of it on cross-examination. I also have been informed

that the parties to the case were served with these responses, so these supplemental responses were served on the other parties in the case, including intervenors.

MR. GUILD: Mr. Chairman, last -- last point, just to make the record. The fact that other documents are accepted, without objection, I note, or where an objection has been asserted and overruled by the Commission, does not provide any precedential support for receiving these documents. I do object to these documents on the grounds that they have been -- that I've asserted, and to -- to the extent they've been served on -- on -- on me, I've -- I've never seen them, and I don't know what that means: "served on the other parties." You know, are they hidden in the -- an ORS website, or are they in a filing of some sort? Service does not overcome any of the objections that I've asserted, even if they have been, indeed, served, so the point is, the fact that this Commission has adopted, without objection from a party, a relaxed rule of evidence on some other exhibit does not provide a blanket authority to receive these

documents with no Company witness on the last day of the hearing, obviously intended for the Commission, not just for curiosity's sake, but to rely on. I mean, unless the Company is prepared to stipulate that they don't offer these documents for proof of the matters asserted -- proof of the truth of the matters asserted, then they do suffer by the -- from the hearsay limitation and the lack of foundation limitation, and I renew my motion to strike.

CHAIRMAN RANDALL: Okay. I think that the foundation that they're on may not be the strongest, but we're going to -- I think we -- we can assign the appropriate weight to them -- to these documents to have them in the record. So, Mr. Guild, I'm going to overrule, and thank you for -- and note -- take notice of your objection.

Commissioners? Commissioner Ervin?

EXAMINATION

BY COMMISSIONER ERVIN:

Q Mr. Hamm, we've had a great deal of testimony and evidence presented about whether certain coal-ash-related expenses required by CAMA in North Carolina

should be allowed or disallowed by ratepayers in South Carolina?

A (HAMM) Yes. DEP Wittliff's -- Wittliff offered that testimony to this Commission yesterday.

Q And you -- you were here to hear that testimony?

A (HAMM) I -- I was, yes, sir.

Q Do you have an opinion, based on the testimony and evidence presented, as to -- to whether or not these expenses should be allowed?

A (HAMM) Well, let's -- let me first make sure we're -- we have challenged, as you are aware, the litigation and legal expenses related to that, and then we've also challenged whether or not ratepayers ought to pay what the DEP witness referred to as the "incremental costs resulting from the passage of the CAMA legislation."

Q What litigation expenses, specifically, do you challenge?

A (HAMM) Coal ash litigation.

Q All -- all coal ash litigation?

A (HAMM) Well, yes, but let -- if you'll let me --

Q Yes, sir.

A (HAMM) -- I'd like to lay the foundation --

Q Yes, sir.

A -- and -- and it's going to take me a moment, but I

think it would be of assistance to the Commission, and with your permission, I'll try to do so.

Q Thank you.

A (HAMM) As this Commission is aware, a Duke operating unit in North Carolina, the Dan River unit, suffered a massive breach with a blockage of the tubes associated with a coal ash basin. That discharge was 39,000 tons of coal ash and another 27 million gallons of coal ash water. I -- I put that down as the predicate.

You then -- I think it's extremely important that you recognize exactly what happened. Duke pled guilty to criminal negligence -- Duke pled guilty to criminal negligence. And I made it a point to look it up because I thought one of you might ask and I want to remind you of what the definition is in North Carolina.

Criminal negligence means: "Reckless or careless -- recklessness or carelessness that shows a thoughtless disregard of consequences or heedless indifference to the safety and rights of others."

They pled guilty to it, which is a -- that is a very significant ruling. Once that came into place, as Duke has made the comment, "Oh, nobody's paying for any of -- of those costs," and it is our

position that the evidence -- I don't care whether it's two pages or 20,000 -- the manner in which they have collected and submitted that information -- I don't believe can even possibly be considered substantial evidence.

And I want to give you some examples, because I have personally -- and I want you to know and maybe you did the same thing when you got that late-filed Report 56 from DEC. I had to go out and get maybe -- and let me say this: Y'all's eyesight may be a heck of a lot better, so my having to get a magnifying glass may be more of a reference to my eyesight, although I doubt that it is, because I had to use this.

I have examined every one of those pages and I believe that if we pull a page out randomly and hand it -- hand it to you, Your Honor, you've a judge. I don't believe there's any way you could determine what the -- what those references are to. You don't know who the parties were.

And I think it's distinctly likely, but again, our position is: If they can't prove their case with clarity, then they don't meet the standard or burden of proof. And -- and I want to -- I'll give you an example.

If you'll look at the documents, you'll see entries for defense of state litigation in coal ash. The settlement that took place was subsequent, obviously, to the spill, and some of those go into 2016 and 2017. I think it's rather disingenuous that the Company tells this Commission and the media, "Oh, citizens and customers are not paying for that," when one of the listings -- several of the listings in there show defense of state action. And if you follow through, and I did -- I looked at each individual law firm entries, and you see entries of several law firms.

One of the difficulties that I was having as a lawyer: Over the years, I have had clients ask me to review legal bills that they had gotten from -- for whatever services -- and, I mean, I have clients that I -- until I left at 20/25 years -- and they would ask me to review it. And I have done so on many occasions.

The descriptions contained in these documents are summary at very, very most and at -- as I know you'll notice, there's all kinds of redactions. And given the redactions, you don't know what they did or what they were doing it for. You don't know who the parties were. And -- but some of the

entries represent defense of state action, but there's also individuals named, where they're fighting a defense for individuals that brought cases. And since it's included in the coal ash litigation expense area, I think the only reasonable conclusion that I or members of this Commission would be: "All right. This is litigation by some individual for coal ash litigation."

Now, to the extent that there was this massive discharge, the Company pled guilty to criminal negligence which is this "recklessness or carelessness that shows a thoughtless disregard of consequences or heedless indifference to the safety and rights of others." And then when I see entries of private lawsuits that -- based on the limited data, I think it calls into significant question whether or not a representation that they're not seeking recovery of those costs is accurate.

So with that foundation, when I looked at these documents that I literally had to go out and get this because I felt like I would be asked --

Q You're talking about what's been marked as Exhibit 71?

A (HAMM) No. I'm talking about all the documents --

Q All the documents?
A (HAMM) -- that I came -- now, remember when I -- I didn't have those documents when I filed my testimony.
Q Right.
A (HAMM) But the documents that I looked at, if the same formatting and given their computer system and the significant limitations it placed on actually telling you anything, I don't think the addition of a pile that size or a pile that reaches the ceiling makes a difference.
Q Would you take a look at them just for a moment? Or -- we -- I think the Chairman's going to give us a break here in just a minute. Would you be willing to take Exhibit Number 71 and look through them and -- and tell me -- since you haven't -- have you seen these documents? Do you know? Have you seen them?
A (HAMM) I -- I believe they -- they came in late after my testimony --
Q Yes.
A (HAMM) -- was filed, but I -- I did look at them.
Q You had a chance to read them?
A (HAMM) But I'll be happy to -- I -- I --
Q Could you do that on the break?

A (HAMM) -- would like to refresh my memory.
Q Because I'm going to -- I'm going to have some further questions for you as it relates to -- to the documents that have been entered into evidence, and when we come back from break, if -- if that's all right with the Chairman. Would that be agreeable to you, Mr. Hamm?
A (HAMM) I am -- I am ready to respond to any question --
Q All right, sir.
A (HAMM) -- that you or any member -- that's why I'm here.
Q I -- I -- I want to be sure that you've seen the documents that are in evidence before I ask you about them, so --
A (HAMM) Right.
Q Let me check --
A (HAMM) I'd be happy to do that.
Q All right. We'll take --
COMMISSIONER ERVIN: Mr. Chairman.
CHAIRMAN RANDALL: We're not going to take a break yet.
COMMISSIONER ERVIN: Yeah. But we'll take one perhaps --
CHAIRMAN RANDALL: Commissioner Whitfield.

EXAMINATION

BY COMMISSIONER WHITFIELD:

Q I've got a couple of questions for each of you. And Mr. Hamm, mine -- I'm going to go with you first -- mine won't pertain to that. We won't need to reference or take a break or anything. I do want to be careful how I ask this. I do think this is a unique opportunity with you being the policy witness and with your background in ethics, and I hope your counsel doesn't jump up on my brief questions for you, but possibly counsel for the Company, but I'm going to toss it out here anyway. And it there needs to be, there's needs to be.

A (HAMM) I'll do my best to answer any question you offer.

Q Mr. Hamm, yesterday I had an exchange with Witness Wittliff, and I think you were in the room --

A (HAMM) I was.

Q -- here yesterday. And Mr. Bateman put up a statute about this Commission being able to enter into an agreement with any other state or federal regulatory body, which -- did you see that?

A (HAMM) Yes. Creates -- it creates the possibility of it; it does not require it.

Q Yes, sir. And I'm certainly -- certainly was aware

of that -- aware of that and aware of that statute. I think what caught me off guard was Mr. Wittliff, in my exchange with him, sort of implied that we could have a "offline meeting" with the North Carolina Commission and there is where -- what led to my hesitation.

With your background in ethics and -- and your being the policy witness, if you will, among other things, for ORS, what -- and, again, I'm certainly aware we could enter into an agreement with other state or federal regulatory bodies -- what could this Commission do -- now that North Carolina has already ruled on the case, what could this Commission do that might help ratepayers in conjunction with another regulatory body or any state or federal body, now that that -- the North Carolina case is over, what could this Commission do to help South Carolina ratepayers in that regard?

A (HAMM) Well, I'll say initially, that I think it would be improper for anybody on the Commission to have a conversation with the commissioner staff in North Carolina --

Q And --

A (HAMM) -- while there's the pending hearing and

this Court, this Commission has not rendered a decision. Any conversations that you might have that even create the suggestion that your decision might be influenced by that conversation, I think would be improper. It is not improper for you to be advised of and be aware of the terms of the North Carolina decision. But I think that that -- that would be the absolute maximum that you could do in my mind lawfully and under the State Ethics Act, which you know I was --

Q Yes.

A (HAMM) -- I was the head of that agency for a little over a year recently.

Q And I thought that's where Mr. Wittliff was going when he made that suggestion, but yes, sir. Go ahead.

A (HAMM) So, on -- on that basis, I -- I -- if you're -- if the question is predicated that the North Carolina has ruled, can you all have some contact with them in any way related to this proceeding, my answer would be a firm no.

Q Yes.

A (HAMM) Now, after this -- this Commission renders its decisions, and I think it would have to render both the DEC and the DEP, could the -- could you

have general conversations about their regulatory policy? I think set up on the right basis, I -- I think we'd have to -- I think it would have to be noticed. Just like you all have ex parte --

Q Allowable.

A (HAMM) -- hearings, I think you could certainly do that. Do I think that's a good idea? You know, I think -- I know this Commission is an active participant in NARUC. I -- I support the Commission doing that because it's important to understand and talk to the people that made decisions in other jurisdictions to help inform you, "Well, I hadn't thought about it that way," and apply that kind of reasoning.

So I -- I think that's the clearest answer that I can give you. But I do want to be -- let there be no misunderstanding. I think it would be improper --

Q Yes.

A (HAMM) -- for the Commission to have any conduct -- contact in that way, and if that were to happen, I think the Company would certainly challenge it, and I'm very confident that they would be successful.

Q Yes, sir. Thank you for your answer on that, Mr.

Hamm. Just one -- one or two more and then I got one for Mr. Morgan and I'm done.

Again, this is kind of -- more of a policy question, so if there's an objection, I'll see, but a lot of debate about the basic facilities charge: the fairness and the equity. But there's also been a lot of testimony in this case about ratepayers in the DEP service territory being low income and being not only low income but those who are the least able to do something about their energy uses despite all the DSM and the EE efforts.

With that in mind, what's your opinion on the lower basic facilities charge and the Company trying to make up the revenue requirement in the usage portion? Volumetric -- or volumetric, yes, sir.

A (HAMM) And the DEP -- the ORS witness Michael Seaman-Huynh testified on that yesterday. And I want to -- I want to start with the position ORS has taken then I'll -- I'm going to go a little bit farther, I think, to be in response to your question.

Ultimately, this case is about revenue. And then, once you all determine an increase, if any, how do you collect it? The basic facilities charge

-- and you also heard from Dr. Ruoff yesterday as well -- the basic facilities charge is a -- it is -- certainly has cost basis to it, but I think the Commission needs to proceed understanding that every time you raise the basic facilities charge, you're having somewhat of a negative impact on especially low-income, low-consumption customers being able to control the savings they get from trying to avoid the next kilowatt. They've got 500 -- if the basic facilities charge is higher and the commodities charge is somewhat lower, it's hard for them to see a price signal. And ultimately, what I think's going to happen is: People ultimately are reacting to their total bill. I think -- I think that the Commission as -- and I think it might've been you yesterday that talked, sir, "Where does this end?" We were talking about costs and other things.

Q And that was going to be my last question of you, so go right ahead.

A (HAMM) Oh, man. Well, you know, I'm trying to be -- I am trying to be absolutely careful that I am making the -- what I think is the best and most honest response to your question.

I think our witness, Dr. Michael Seaman-Huynh

-- Dr. Ruoff, made some very important points to the Commission, and since this has come up and you've asked me, there was some question by counsel for Duke yesterday, "Well, wait a minute. Dr. Ruoff's testimony is somewhat different than Michael Seaman-Huynh's, and to some extent they're -- that's true. But you need to understand that ORS, through our director, Nannette Edwards, was trying to give the Commission a little bit broader background to help you make decisions and -- because this -- as you recognize, we are -- we did not offer a specific number. Michael Seaman-Huynh's testimony was intended to say, "To the extent that you give an increase, whether it's a dollar or whatever," he basically said, you know, that "no more than 25 percent ought to go to the basic facilities charge."

I think Dr. Ruoff testified that he thought it shouldn't increase at all, and that is one of those basic foundations that this Commission is going to have to rule on. And I am -- I am personally -- and I thought the idea of bringing in Dr. Ruoff with a slightly different viewpoint -- and he has years of experience. He's -- he's been over here many times. I've known him for 35 years. I -- I

think he made an effective presentation, whether the Commission does or not. But he was trying to point out what the impact on low-income people, and it's true. There's a lot of citizens that out there are deciding, "Well, am I going to pay my power bill, or do I get my medicine?" or whatever. And I'm not trying to intrude into that, but both ORS and through the testimony of Michael Seaman-Huynh and the testimony of Dr. Ruoff, we're just trying to lay out what some of those consequences are. And I think -- I think both ORS through Michael Seaman-Huynh and through the testimony of Dr. Ruoff are -- are clearly indicating some caution in those increases, because we had the word "gradualism."

Certainly, an increase of several hundred percent in any component of an electric bill is -- I think would -- would serve -- would not serve all the customers well to begin with, but I think that kind of an increase on the low-income, low-consumption people would be -- would be against the public policy of having people buy less electricity. So you're trying to slow down consumption so you're not building another -- either a peaking unit or base-load plants, because

any of which are -- are very, very expensive.

I hope that was responsive to you. I'm not sure what else I can say to you, because I don't -- you know, I am not the witness who testified on the basic facilities charge. What I have said is a culmination of my discussions with Michael Seaman-Huynh and the materials I reviewed from Dr. Ruoff.

CHAIRMAN RANDALL: Okay. We're going to take a break. Now, you told us you've seen these a couple of times.

WITNESS HAMM: Well, I --

CHAIRMAN RANDALL: You've told us twice you've looked at these, but you get a chance right now --

WITNESS HAMM: Well, I --

CHAIRMAN RANDALL: -- if you need to, so you can answer anything else Commissioner Ervin needs. And we're going to take a break and we'll be back. Commissioner Whitfield's still got questions, but we're going to take a ten-/fifteen-minute break.

WITNESS HAMM: Yes, sir. I'll be here, I promise.

(Off the record from 11:25 a.m. until 11:38 a.m.)

CHAIRMAN RANDALL: Okay. We'll call us back to order. Commissioner Whitfield, I think you had another question.

THE EXAMINATION BY COMMISSIONER WHITFIELD CONTINUES.

Q Yes. And thank you, Mr. Hamm, for your answers. That -- that was pretty much it when you made the comment "Where will it end?" I was referencing coal ash, but you've -- you've really answered my questions, and I appreciate it.

Mr. Morgan, I do have one for you. On Page 5 of your prefiled direct testimony, you propose eliminating the expenses in the highest and lowest years -- I'm talking about storm costs now -- and to use -- and to use an eight-year average expense level. Do you see large variances in the highest and lowest years or -- or are they somewhat in line with the remaining -- remaining information?

A (MORGAN) Yes, sir. There was some variance. For example, one year that number was zero in 2012, and in 2016, that number was -- let me see -- a little over -- well, about -- a little over $29.5 million. So those numbers varied and I think, you know, given our recommendation, that was -- that -- that was fitting.

Q You used the eight-year average?

A (MORGAN) Right. Well, using a -- a ten-year average, but only using the -- excuse me, using ten years of data, but using only eight of those ten with the lows and highs removed.

Q I see. That's all I have. Thank you, Mr. Morgan.

COMMISSIONER WHITFIELD: Thank you, Mr. Chairman.

CHAIRMAN RANDALL: Thank you. Commissioner Hamilton.

COMMISSIONER HAMILTON: Thank you, Mr. Chairman.

EXAMINATION

BY COMMISSIONER HAMILTON:

Q Good morning, gentlemen.

A (MORGAN) Good morning, Commissioner --

A (HAMM) Good morning.

A (MORGAN) -- Hamilton.

Q All right. I -- I had hoped I wouldn't see you in the afternoon, but we might --

A (MORGAN) Well, it's still morning.

A (HAMM) We're always happy to see you.

Q We're still around. We've got a few minutes, but Mr. Morgan, I've got one question for you. Did the ratepayers of South Carolina receive any benefit at all from the Company violating the terms of the

CertainTEED contract?

A (MORGAN) No, sir. The violation -- well, them not adhering to the agreement, no, sir.

Q None whatsoever?

A (MORGAN) No, sir. They benefited from the -- the contract as it was written initially, of course, with the payment received from CertainTEED that was outlined in the contract. But the -- the breach of the contract, no, sir.

Q All right. Thank you gentleman very much. Appreciate you being here.

A (MORGAN) Thank you.

CHAIRMAN RANDALL: Thank you. Commissioner Ervin.

COMMISSIONER ERVIN: Thank you, Mr. Chairman.

EXAMINATION

BY COMMISSIONER ERVIN:

Q Mr. Hamm, you've had a chance now on the break to review the documentation that was marked as the next exhibit.

A (HAMM) Yes, sir. I did.

Q What can you tell us about it?

A (HAMM) Well, actually, I have a couple of reactions to it. Number one, I -- I -- I think it is amazing that shortly before the hearing they

suddenly come up with all of these documents, and I didn't react well to an assertion in one of these that, well, if we'd just asked the question. Well, we believe we asked the questions. When you ask for invoices and what they -- as you'll recall, what they originally did, they just gave us a -- an invoice number and what the dollar amount and that was it. Now I don't -- I have -- I certainly wonder, in management of Duke, who thought that could possibly be -- forget the ORS. I don't know how anybody could have thought, "Well, the Commission will know what that expense is and what it's related to." I don't have mindreading skills, nor should I in a matter as serious as this.

I think this is -- in many cases -- they've given us a lot more documents, but my reaction is very much the same. If you look at any of the particular pages and you see these lists and lists, you still don't know -- the one thing that I noticed that they hadn't said to us in the beginning is the -- we originally expressed concern about this historic treatment of insurance coverage and pollution control. I'm trying to remember the exact phrase. I saw a page in there that said that they were looking into and making claims on third-

party excess coverage, and I'm familiar with what that means.

But I -- I go back -- I want to go back to the point that what prompted all of this. What prompted all of this was Duke had a major, major disaster accident at Dan River with the -- well, you already know, the 39,000 tons and all the water -- and it's very difficult for me to -- to believe that these are not related to that, to which they pled guilty to criminal negligence, and I could certainly see why an insurance carrier would say, "Wait a minute. You pled guilty to criminal negligence, and we have provisions in our policies where you engage in conduct or result in judgments in certain areas, you lose your coverage." So it's difficult for me -- I don't think it is being accurate on the record to say, "Oh, we're not trying to collect anything related to the Dan River accident." I think the consequence of that are flowing through these. There's a limited glimpse when you see actions filed by citizens related to that. Again, we don't know any of the details. We don't know who the parties are.

And I -- and I think it's -- I'm still having a problem when they say they're defending state

actions against them. One of the things that really jumped out at me yesterday, listening to the hearing, which I -- which I thought was pretty -- was subtle, and I'm -- I'm glad I'm getting a chance to make this observation to it --

CHAIRMAN RANDALL: We're getting beyond the -- what we were talking about.

WITNESS HAMM: I'm just trying to respond to his question, and I'll stop.

CHAIRMAN RANDALL: I guess --

COMMISSIONER ERVIN: Well, finish your thought and then --

A (HAMM) Well, Witness Coppola said, "Oh, well. We didn't plead guilty." Well, they had entered into settlement agreements. They ended up doing whatever the regulatory agency or the state government did, and they're saying, "Because we didn't get to a judgment, we settled and had to pay certain costs; therefore, ratepayers ought to pay for all of it." And I strongly disagree with that, but there's no way to know in this record what they are.

Q Thank you, sir.

A (HAMM) Yes, sir.

COMMISSIONER ERVIN: Those are all the

questions I have.

CHAIRMAN RANDALL: Commissioners, any other questions? Commissioner Belser.

EXAMINATION

BY COMMISSIONER BELSER:

Q Good morning, Mr. Morgan, how are you?

A (MORGAN) Good morning, Commissioner Belser.

Q You had some testimony on the amortization of the AMI meters, I believe.

A (MORGAN) Yes, sir. Yes, ma'am, sorry.

Q Thank you. And I believe you -- you -- you -- it was 15 years is your proposal?

A (MORGAN) Yes.

Q And you're tying that to the service life.

A (MORGAN) Yes.

Q Is that correct?

A (MORGAN) Yes.

Q Now, as far as depreciation rates for those AMI meters, will that be the same term: 15 years?

A (MORGAN) Yes.

Q Okay. Thank you very much.

A (MORGAN) Thank you.

CHAIRMAN RANDALL: Thank you. Commissioners, anything else? Any other questions? Mr. Knowles, any redirect?

MR. KNOWLES: No, sir. Thank you.
CHAIRMAN RANDALL: Thank you. Gentleman, thank you for your --
MR. ELLERBE: Mr. Chairman.
CHAIRMAN RANDALL: Yes.
MR. ELLERBE: May I follow up on some of the Commissioner questions briefly?
MS. EDWARDS: I would object on the grounds that there's no recross if there's no redirect.
COMMISSIONER ERVIN: You need to get to a microphone.
MS. EDWARDS: Oh.
COMMISSIONER ERVIN: They can't hear you.
MS. EDWARDS: I'm sorry. I would object on the grounds that you typically do not allow --
COMMISSIONER BELSER: It's his witness.
MS. EDWARDS: Oh, thank you.
MR. ELLERBE: Yeah.
MS. EDWARDS: Thank you.
MR. KNOWLES: Thank you, Ms. Edwards. Mr. Chairman, ORS would object on the grounds that if there's no redirect, there's no recross.
CHAIRMAN RANDALL: Briefly.
MR. ELLERBE: Thank you, Mr. Chairman.

RECROSS-EXAMINATION

BY MR. ELLERBE:

Q Mr. Hamm, as you look through Exhibit 71, it sounds like you found that there was in the stack of documents narrative explanations of the various litigation matters.

A (HAMM) I found wording. I didn't find wording that I -- the standard that I apply is: Would the Commission understand what this means, since the "substantial evidence" rule. I found narrative. I didn't find it to be particularly illuminating as to what was going on.

Q But it's not all spreadsheet material, correct? You found narrative discussion of litigation?

A (HAMM) In fairness, the answer to that is yes.

Q Thank you, sir. And would you agree with me in the future that it would be the best way to get answers to the kind of questions that you were talking about is: "What is -- what's the litigation about? Does it arise out of Dan River? Does it not?"

The best way to get at that is not to ask for legal invoices or to go through legal invoices, especially redacted legal invoices. Do you agree with that?

A (HAMM) Not necessarily, no.

Q Okay. Well, you understand that ORS asked for legal invoices? We talked about --
A (HAMM) Yes.
Q -- that last week.
A (HAMM) And we didn't get -- we got a cover sheet. We didn't get any information as to the services rendered, what was rendered behind the numbers. I mean, I was honestly shocked that the Company thought that giving us invoice numbers and dollar amounts in any way provided the Commission with information supporting what you're asking for. I'm -- I'm still puzzled and amazed and -- and what you -- and 71 is, in many respects, more of the same.
Q Do you agree with me that the Commission's decision on the issues presented in this case are based on the record in this case, which is -- which would include testimony from the Company's witnesses who talked about these various issues as well as testimony from the ORS, correct, sir?
A (HAMM) After 40-plus years, yes. I think the Commission must make a decision based on the evidence in this case and no other source or data. I'm just telling you --
Q Yes, sir.
A (HAMM) -- I don't see how the Commission can get

there on what you put in the evidence.
Q Well, the Commission -- Commission also has the testimony of Mr. Kerin and Dr. Wright and --
A (HAMM) Oh, I'm not --
Q -- other witnesses --
A (HAMM) -- contesting that. The --
Q Thank you, sir.
CHAIRMAN RANDALL: Let's dong start talking over each other, because Ms. Tackett's not that good. She's great, but, okay. We're done?
COMMISSIONER ERVIN: Done.
MR. HAMM: She is great, Mr. Chairman. I'm sorry.
CHAIRMAN RANDALL: Thank you for your -- thank you for your testimony. You may be excused.
(Witnesses excused)
CHAIRMAN RANDALL: Anything else?
MS. EDWARDS: Yes, sir.
CHAIRMAN RANDALL: Ms. Edwards.
MS. EDWARDS: A couple of just cleanup items. One, I do want to make sure that we got in the -- the stipulation on prepaid. ORS had a witness, Sarah Johnson, but she will not be presented, and I -- I think we moved in the

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 57 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN
1 SUMMER CP DEMAND ALLOCATION

Line No.	Description	TOTAL SYSTEM	SC RETAIL	SC RES	SC SGS	SC SGSCLR	SC MGS	SC LGS	SC SI	SC TSS
1	DISTRIBUTION PLANT IN SERVICE, Excluding 371, 373, and Extra Facilities	5,494,678,273	661,411,897	474,863,326	73,585,834	1,654,251	72,709,474	29,531,695	5,303,935	360,972
2	Distribution Customer Class Allocations for Projections		100.00%	71.80%	11.13%	0.25%	10.99%	4.46%	0.80%	0.05%
3										
4	Transmission Peak	12,734,339	1,185,427	487,425	79,952	610	323,515	291,026	2,789	110
5	Transmission Peak Percentage		100.00%	41.12%	6.74%	0.05%	27.29%	24.55%	0.24%	0.01%
6										
7										
8	Distribution & Transmission General Plant	351,396,160	40,438,477	22,811,687	3,570,604	70,695	5,506,148	3,687,110	233,829	15,241
9	Distribution & Transmission General Plant Allocation		100.00%	56.41%	8.83%	0.17%	13.62%	9.12%	0.58%	0.04%
10										
11	**Phase 1 Rate Step up**									
12	Distribution Revenue Requirement		$ 2,750,885	$ 1,975,009	$ 306,052	$ 6,880	$ 302,407	$ 122,826	$ 22,060	$ 1,501
13	Transmission Revenue Requirement		862,660	354,710	58,183	444	235,428	211,785	2,030	80
14	General Intangible Plant (Communications / Enterprise Systems)		1,521,406	858,238	134,336	2,660	207,156	138,719	8,797	573
15	Total (Sum L12 through L14)		$ 5,134,951	$ 3,187,957	$ 498,570	$ 9,984	$ 744,991	$ 473,330	$ 32,887	$ 2,155
16		Check Total	$0							
17	Customer % for Distribution Investments based on Current Investments		57.44%	64.09%	74.67%	95.51%	23.05%	2.77%	12.33%	96.34%
18										
19	Customer Related Portion (L12 * L17)		$ 1,580,061	$ 1,265,847	$ 228,517	$ 6,571	$ 69,720	$ 3,403	$ 2,719	$ 1,446
20	Non-Customer Related Portion (L15 - L19)		3,554,890	1,922,110	270,053	3,413	675,272	469,927	30,168	709
21	Total Revenue Requirement (Sum L19 through L20)		$ 5,134,951	$ 3,187,957	$ 498,570	$ 9,984	$ 744,991	$ 473,330	$ 32,887	$ 2,155
	Phase 2 Rate Step up									
22	Distribution Revenue Requirement		$ 3,208,510	$ 2,303,563	$ 356,965	$ 8,025	$ 352,714	$ 143,258	$ 25,729	$ 1,751
23	Transmission Revenue Requirement		722,123	296,924	48,704	371	197,074	177,283	1,699	67
24	General Intangible Plant (Communications / Enterprise Systems)		1,858,104	1,048,172	164,065	3,248	253,001	169,419	10,744	700
25	Total (Sum L22 through L24)		$ 5,788,737	$ 3,648,658	$ 569,735	$ 11,645	$ 802,790	$ 489,960	$ 38,173	$ 2,519
26		Check Total	$0							
27	Customer % for Distribution Investments based on Current Investments		57.44%	64.09%	74.67%	95.51%	23.05%	2.77%	12.33%	96.34%
28										
29	Customer Related Portion (L22 * L27)		$ 1,842,913	$ 1,476,428	$ 266,532	$ 7,664	$ 81,318	$ 3,969	$ 3,171	$ 1,687
30	Non-Customer Related Portion (L25 - L29)		3,945,824	2,172,231	303,202	3,980	721,472	485,991	35,001	832
31	Total Revenue Requirement (Sum L28 through L30)		$ 5,788,737	$ 3,648,658	$ 569,735	$ 11,645	$ 802,790	$ 489,960	$ 38,173	$ 2,519

Lines 1 - 9 from Cost of Service Study.
Lines 12-14 from Bateman Exhibit 4 Page 2, lines 71-73.
Lines 22 - 24 from Bateman Exhibit 4 Page 4, lines 83-85.

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 58 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN
1 SUMMER CP DEMAND ALLOCATION

Bateman Exhibit 4
Page 1 Cont.

Line No.	Description	SC ALS	SC SLS	SC SFL
1	DISTRIBUTION PLANT IN SERVICE, Excluding 371, 373, and Extra Facilities	2,266,723	998,557	137,130
2	Distribution Customer Class Allocations for Projections	0.34%	0.15%	0.02%
3				
4	Transmission Peak	0	0	0
5	Transmission Peak Percentage	0.00%	0.00%	0.00%
6				
7				
8	Distribution & Transmission General Plant	2,700,029	1,837,683	5,453
9	Distribution & Transmission General Plant Allocation	6.68%	4.54%	0.01%
10				
11	**Phase 1 Rate Step up**			
12	Distribution Revenue Requirement	$ 9,428	$ 4,153	$ 570
13	Transmission Revenue Requirement	-	-	-
14	General Intangible Plant (Communications / Enterprise Systems)	101,582	69,139	205
15	Total (Sum L12 through L14)	$ 111,010	$ 73,292	$ 775
16				
17	Customer % for Distribution Investments based on Current Investments	0.00%	41.08%	23.07%
18				
19	Customer Related Portion (L12 * L17)	$ -	$ 1,706	$ 132
20	Non-Customer Related Portion (L15 - L19)	111,010	71,586	644
21	Total Revenue Requirement (Sum L19 through L20)	$ 111,010	$ 73,292	$ 775
	Phase 2 Rate Step up			
22	Distribution Revenue Requirement	$ 10,996	$ 4,844	$ 665
23	Transmission Revenue Requirement	-	-	-
24	General Intangible Plant (Communications / Enterprise Systems)	124,063	84,440	251
25	Total (Sum L22 through L24)	$ 135,059	$ 89,284	$ 916
26				
27	Customer % for Distribution Investments based on Current Investments	0.00%	41.08%	23.07%
28				
29	Customer Related Portion (L22 * L27)	$ -	$ 1,990	$ 153
30	Non-Customer Related Portion (L25 - L29)	135,059	87,294	762
31	Total Revenue Requirement (Sum L28 through L30)	$ 135,059	$ 89,284	$ 916

Lines 1 - 9 from Cost of Service Study.
Lines 12-14 from Bateman Exhibit 4 Page 2, lines 71-73.
Lines 22 - 24 from Bateman Exhibit 4 Page 4, lines 83-85.

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 1
REVENUE REQUIREMENT
For the period January 1, 2019 through December 31, 2019

Line No.	Description		Total SC Retail	Depreciation Rate	Depreciation
1	Impact to Rate Base Line Items				
2	Additions to gross electric plant:				
3	Distribution [1]	$	13,669,981	2.43%	$ 332,181
4	Transmission [1]		4,865,943	1.91%	92,940
5	General - Advanced DMS [1]		879,434	10.00%	87,943
6	General - Communication [1]		2,436,016	5.00%	121,801
7	General - Enterprise Applications [1]		1,186,120	20.00%	237,224
8	Impact to electric plant in service (Sum L3 through L7	$	23,037,494		$ 872,088
9					
10	Accumulated depreciation & amortization:				
11	Distribution accumulated depreciation (-L3	$	(332,181)		
12	Transmission accumulated depreciation (-L4		(92,940)		
13	General Plant accumulated depreciation (-Sum L5 through L7		(446,968)		
14	Impact to accumulated depreciation (Sum L11 through L13	$	(872,088)		
15					
16	Net electric plant:				
17	Distribution (L3 + L11)	$	13,337,801		
18	Transmission (L4 + L12)		4,773,003		
19	General Plant (L5 + L6 + L7 + L13		4,054,601		
20	Impact to net plant (Sum L17 through L19	$	22,165,405		
21					
22	Cost of Capital [2]	9.36%			
23					
24	Rate Base Revenue Requirement				
25	Distribution (L17 * L22)	$	1,249,051		
26	Transmission (L18 * L22		446,980		
27	General Plant (L19 * L22		379,703		
28	Impact to net plant (Sum L25 through L27	$	2,075,733		
29					
30	Impact to Income Statement Line Items				
31	Depreciation and amortization:				
32	Distribution depreciation expense (L3	$	332,181		
33	Transmission depreciation expense (L4		92,940		
34	General Plant depreciation expense (Sum L5 through L7		446,968		
35	Impact to deprec. and amortization (Sum L32 through L34	$	872,088		
36					

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 59 of 78

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 60 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE I
REVENUE REQUIREMENT
For the period January 1, 2019 through December 31, 2019

Line No.	Description		Total SC Retail
37	Amortization of 2019 deferral:		
38	Distribution depreciation expense [3]		$ 977,573
39	Transmission depreciation expense [3]		302,335
40	General Plant depreciation expense [3]		672,503
41	Impact to deprec. and amortization (Sum L38 through L40)		$ 1,952,411
42			
43	General taxes:		
44	Property tax rate - South Carolina	1.3565%	
45	Property tax rate - Combined North Carolina and South Carolina	0.3815%	
46			
47	Distribution property tax expense (L3 * L44)		$ 185,427
48	Transmission property tax expense (L4 * L45)		18,564
49	General Plant property tax expense (Sum(L5 through L7) * L45)		17,174
50	Impact to general taxes (Sum L47 through L49)		$ 221,166
51			
52	Income Taxes	24.95%	
53	Distribution (L32 + L38 + L47) * -L52		$ (373,048)
54	Transmission (L33 + L39 + L48) * -L52		(103,253)
55	General Plant (L34 + L40 + L49) * -L52		(283,593)
56	Total income taxes (Sum L53 through L55)		$ (759,894)
57			
58	Total Income statement impact		
59	Distribution (L32 + L38 + L47 + L53)		$ 1,122,133
60	Transmission (L33 + L39 + L48 + L54)		310,586
61	General Plant (L34 + L40 + L49 + L55)		853,052
62	Total income statement impact (Sum L59 through L61)		$ 2,285,772
63			
64	Income Statement Requirement	74.72% [4]	
65	Distribution (L59 / L64)		$ 1,501,834
66	Transmission (L60 / L64)		415,681
67	General Plant (L61 / L64)		1,141,703
68	Total income statement Requirement (Sum L65 through L67)		$ 3,059,218

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 61 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE I
REVENUE REQUIREMENT
For the period January 1, 2019 through December 31, 2019

Line No.	Description	Total SC Retail
69		
70	Total Revenue Requirement for Plant additions and Deferral	
71	Distribution (L25 + L65)	$ 2,750,885
72	Transmission (L26 + L66)	862,660
73	General Plant (L27 + L67)	1,521,406
74	Total Revenue Requirement (Sum L71 through L73)	$ 5,134,951

[1] Bateman Exhibit 4 page 3, lines 7-11 May, 2020.
[2] Bateman Exhibit 4 page 7, line 5.
[3] Bateman Exhibit 4 page 3, lines 114-116
[4] Bateman Exhibit 4 page 7, line 24.

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 62 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 1
For the period January 1, 2019 through December 31, 2019

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 3

Line No.	Calculation of South Carolina Retail Costs	2019 Jan	2019 Feb	2019 Mar	2019 Apr	2019 May	2019 Jun	2019 Jul	2019 Aug	2019 Sep	2019 Oct	2019 Nov	2019 Dec
1	Plant-in-Service: [1]										-		
2	Distribution to Plant in Service	1,286,784	1,125,745	1,125,745	1,125,745	1,125,745	1,125,745	1,125,745	1,125,745	1,125,745	1,125,745	1,125,745	1,125,745
3	Transmission to Plant in Service	366,881	597,027	144,481	956,748	963,629	962,547	145,772	145,772	145,772	145,772	145,772	145,772
4	Advanced DMS Plant in Service												879,434
5	Communications Plant in Service	267,950	125,760	258,291	198,224	198,224	198,224	198,224	198,224	198,224	198,224	198,224	198,224
6	Enterprise Applications Plant in Service	-	-	-	-	-	-	-	-	-	-	-	1,186,120
7	Cumulative Distribution investment (L2)	1,286,784	2,412,529	3,538,275	4,664,020	5,789,765	6,915,510	8,041,255	9,167,001	10,292,746	11,418,491	12,544,236	13,669,981
8	Cumulative Transmission investment (L3)	366,881	963,909	1,108,390	2,065,138	3,028,767	3,991,314	4,137,085	4,282,857	4,428,628	4,574,400	4,720,171	4,865,943
9	Cumulative Advanced DMS investment (L4)												879,434
10	Cumulative Communication investment (L5)	267,950	393,710	652,001	850,225	1,048,449	1,246,673	1,444,896	1,643,120	1,841,344	2,039,568	2,237,792	2,436,016
11	Cumulative Enterprise Application investment (L6)	-	-	-	-	-	-	-	-	-	-	-	1,186,120
12													
13	Accumulated depreciation & amortization:												
14	Distribution plant depreciation rate [2]	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%
15	Transmission plant depreciation rate [2]	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%
16	Advance DMS plant depreciation rate [2]	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
17	Communication plant depreciation rate [2]	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
18	Enterprise Application plant depreciation rate [2]	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
19	Distribution depreciation expense (L7 * L14)	-	2,606	4,885	7,165	9,445	11,724	14,004	16,284	18,563	20,843	23,122	25,402
20	Transmission depreciation expense (L8 * L15)	-	584	1,534	1,764	3,287	4,821	6,353	6,585	6,817	7,049	7,281	7,513
21	Advanced DMS depreciation expense (L9 * L16)	-	-	-	-	-	-	-	-	-	-	-	-
22	Communication depreciation expense (L10 * L17)	-	1,116	1,640	2,717	3,543	4,369	5,194	6,020	6,846	7,672	8,498	9,324
23	Enterprise Application depreciation expense (L11 * L18)	-	-	-	-	-	-	-	-	-	-	-	-
24	Distribution accumulated depreciation	-	(2,606)	(7,491)	(14,656)	(24,101)	(35,825)	(49,829)	(66,112)	(84,676)	(105,518)	(128,641)	(154,043)
25	Transmission accumulated depreciation	-	(584)	(2,118)	(3,882)	(7,169)	(11,990)	(18,343)	(24,928)	(31,745)	(38,794)	(46,075)	(53,588)
26	Advanced DMS accumulated depreciation	-	-	-	-	-	-	-	-	-	-	-	-
27	Communication accumulated depreciation	-	(1,116)	(2,757)	(5,474)	(9,016)	(13,385)	(18,579)	(24,600)	(31,446)	(39,118)	(47,616)	(56,941)
28	Enterprise Application accumulated depreciation	-	-	-	-	-	-	-	-	-	-	-	-
29													
30	Net electric plant												
31	Distribution (L7 + L24)	1,286,784	2,409,924	3,530,784	4,649,364	5,765,664	6,879,685	7,991,426	9,100,888	10,208,070	11,312,972	12,415,595	13,515,938
32	Transmission (L8 + L25)	366,881	963,325	1,106,272	2,061,256	3,021,598	3,979,323	4,118,742	4,257,929	4,396,884	4,535,606	4,674,097	4,812,355
33	Advanced DMS (L9 + L26)	-	-	-	-	-	-	-	-	-	-	-	879,434
34	Communication (L10 + L27)	267,950	392,594	649,244	844,751	1,039,432	1,233,288	1,426,317	1,618,521	1,809,898	2,000,450	2,190,175	2,379,075
35	Enterprise Application (L11 + L28)	-	-	-	-	-	-	-	-	-	-	-	1,186,120
36	Average rate base - Distribution	643,392	1,848,354	2,970,354	4,090,074	5,207,514	6,322,675	7,435,556	8,546,157	9,654,479	10,760,521	11,864,284	12,965,767
37	Average rate base - Transmission	183,441	665,103	1,034,798	1,583,764	2,541,427	3,500,461	4,049,033	4,188,336	4,327,406	4,466,245	4,604,852	4,743,226
38	Average rate base - Advanced DMS	-	-	-	-	-	-	-	-	-	-	-	439,717
39	Average rate base - Communication	133,975	330,272	520,919	746,998	942,092	1,136,360	1,329,802	1,522,419	1,714,209	1,905,174	2,095,313	2,284,625
40	Average rate base - Enterprise Application	-	-	-	-	-	-	-	-	-	-	-	593,060
41													

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 63 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 1
For the period January 1, 2019 through December 31, 2019

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 3

Line No.	Calculation of South Carolina Retail Costs	2019 Jan	2019 Feb	2019 Mar	2019 Apr	2019 May	2019 Jun	2019 Jul	2019 Aug	2019 Sep	2019 Oct	2019 Nov	2019 Dec
42	Return on rate base:												
43	Long-term debt [4]	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%
44	Members' equity [4]	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%
45	Distribution Debt return on rate base (L36 x L43 / 12)	1,023	2,939	4,723	6,504	8,281	10,054	11,824	13,590	15,352	17,111	18,866	20,618
46	Transmission Debt return on rate base (L37 x L43 / 12)	292	1,058	1,646	2,518	4,041	5,566	6,439	6,660	6,881	7,102	7,322	7,543
47	Advance DMS Debt return on rate base (L38 x L43 / 12)	-	-	-	-	-	-	-	-	-	-	-	699
48	Communication Debt return on rate base (L39 x L43 / 12)	213	525	828	1,188	1,498	1,807	2,115	2,421	2,726	3,030	3,332	3,633
49	Enterprise Application Debt return on rate base (L40 x L43 / 12)	-	-	-	-	-	-	-	-	-	-	-	943
50	Distribution Equity return on rate base (L36 x L44 / 12)	3,976	11,421	18,354	25,273	32,178	39,069	45,946	52,809	59,657	66,492	73,312	80,118
51	Transmission Equity return on rate base (L37 x L44 / 12)	1,134	4,110	6,394	9,786	15,704	21,630	25,020	25,881	26,740	27,598	28,454	29,309
52	Advance DMS Equity return on rate base (L38 x L44 / 12)	-	-	-	-	-	-	-	-	-	-	-	2,717
53	Communication Equity return on rate base (L39 x L44 / 12)	828	2,041	3,219	4,616	5,821	7,022	8,217	9,407	10,592	11,772	12,947	14,117
54	Enterprise Application Equity return on rate base (L40 x L44 / 12)	-	-	-	-	-	-	-	-	-	-	-	3,665
55													
56	Other operation and maintenance expense: [3]												
57	Distribution O&M	28,907	28,907	28,907	28,907	28,907	28,907	28,907	28,907	28,907	28,907	28,907	28,907
58	Transmission O&M	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402
59	General Plant O&M	61,653	61,653	61,653	61,653	61,653	61,653	61,653	61,653	61,653	61,653	61,653	61,653
60	Total O&M	91,963	91,963	91,963	91,963	91,963	91,963	91,963	91,963	91,963	91,963	91,963	91,963
61													
62	Depreciation and amortization:												
63	Distribution depreciation expense (L19)	-	2,606	4,885	7,165	9,445	11,724	14,004	16,284	18,563	20,843	23,122	25,402
64	Transmission depreciation expense (L20)	-	584	1,534	1,764	3,287	4,821	6,353	6,585	6,817	7,049	7,281	7,513
65	General Plant depreciation expense (Sum(L21: L23))	-	1,116	1,640	2,717	3,543	4,369	5,194	6,020	6,846	7,672	8,498	9,324
66	Total Depreciation	-	4,306	8,060	11,646	16,274	20,914	25,551	28,889	32,226	35,564	38,902	42,239
67													
68	General taxes:												
69	Property tax rate - South Carolina	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%
70	Property tax rate - Combined North Carolina and South Carolina	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%
71													
72	Distribution property tax expense												
73	Transmission property tax expense												
74	General Plant property tax expense												
75	Impact to general taxes (Sum (L72:L74)	-	-	-	-	-	-	-	-	-	-	-	-
76													
77	Total impact to operating income:												
78	Distribution (L57 + L63 + L72)	28,907	31,513	33,792	36,072	38,352	40,631	42,911	45,190	47,470	49,750	52,029	54,309
79	Transmission (L58 + L64 + L73)	1,402	1,986	2,937	3,167	4,689	6,223	7,755	7,987	8,219	8,451	8,683	8,915
80	General Plant (L59 + L65 + L74)	61,653	62,770	63,294	64,370	65,196	66,022	66,848	67,674	68,500	69,326	70,152	70,977
81													
82	Amount for Deferral:												
83	Distribution impact to operating income (L45 + L50 + L78)	33,906	45,873	56,870	67,849	78,811	89,754	100,680	111,589	122,479	133,352	144,207	155,045
84	Transmission impact to operating income (L46 + L51 + L79)	2,828	7,154	10,976	15,471	24,435	33,420	39,214	40,528	41,841	43,151	44,460	45,767
85	General plant impact to operating income (sum(L47:49) + sum(L52:54) + L80)	62,694	65,336	67,341	70,174	72,515	74,851	77,180	79,502	81,818	84,128	86,431	96,752
86	Total	99,427	118,363	135,187	153,494	175,761	198,025	217,074	231,619	246,138	260,631	275,098	297,564
87	Distribution Cumulative amount for deferral	33,906	79,878	137,080	205,563	285,374	376,563	479,177	593,267	718,880	856,067	1,004,877	1,165,361
88	Transmission Cumulative amount for deferral	2,828	9,990	21,003	36,565	61,168	94,873	134,542	175,741	218,488	262,791	308,657	356,095
89	General Plant Cumulative amount for deferral	62,694	128,213	196,111	267,232	341,101	417,729	497,126	579,302	664,266	752,028	842,599	944,012
90													
91	Balance for return												
92	Distribution Balance for Return (Prior Month L89 + Current Month L89 /2)	16,953	56,941	108,645	171,638	245,969	331,686	428,837	537,472	657,640	789,391	932,773	1,087,839
93	Transmission Balance for Return (Prior Month L90 + Current Month L90 /2)	1,414	6,413	15,515	28,829	48,951	78,163	114,936	155,477	197,567	241,215	286,427	333,211
94	General Plant Balance for Return (Prior Month L90 + Current Month L90 /2)	31,347	95,545	162,440	232,145	304,843	380,304	458,536	539,551	623,357	709,965	799,384	895,636
95													

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 64 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 1
For the period January 1, 2019 through December 31, 2019

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 3

Line No.	Calculation of South Carolina Retail Costs Description	2019 Jan	2019 Feb	2019 Mar	2019 Apr	2019 May	2019 Jun	2019 Jul	2019 Aug	2019 Sep	2019 Oct	2019 Nov	2019 Dec
96	Return on Deferred Balance												
97	After Tax Long-term debt [4]	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%
98	After Tax Members' equity [4]	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%
99	Distribution Debt Return on Deferral (L92 * L97/12)	20	68	130	205	294	396	512	641	785	942	1,113	1,298
100	Transmission Debt Return on Deferral (L93 * L97/12)	2	8	19	34	58	93	137	186	236	288	342	398
101	General Plant Debt Return on Deferral (L94 * L97/12)	37	114	194	277	364	454	547	644	744	847	954	1,069
102	Distribution Equity Return on Deferral (L92 * L98/12)	79	264	504	796	1,141	1,538	1,989	2,493	3,050	3,661	4,326	5,045
103	Transmission Equity Return on Deferral (L93 * L98/12)	7	30	72	134	227	362	533	721	916	1,119	1,328	1,545
104	General Plant Equity Return on Deferral (L94 * L98/12)	145	443	753	1,077	1,414	1,764	2,126	2,502	2,891	3,292	3,707	4,154
105	Total (Sum L99:L104)	290	927	1,671	2,523	3,497	4,607	5,844	7,187	8,621	10,149	11,770	13,508
106													
107	Total Deferred balance												
108	Distribution deferral (L83 + L99 + L102)	34,005	46,205	57,504	68,850	80,245	91,688	103,181	114,723	126,314	137,955	149,646	161,388
109	Transmission deferral (L84 + L100 + L103)	2,836	7,191	11,067	15,640	24,720	33,875	39,884	41,435	42,993	44,558	46,130	47,710
110	General Plant deferral (L85 + L101 + L104)	62,877	65,893	68,288	71,527	74,293	77,068	79,853	82,648	85,453	88,267	91,092	101,974
111	Total Sum (L108:L110)	99,717	119,289	136,859	156,017	179,258	202,632	222,918	238,805	254,759	270,780	286,869	311,072
112													
113	Annual Amortization												
114	Distribution amortization amount (L108/2)												
115	Transmission amortization amount (L109/2)												
116	General Plant amortization amount (L110/2)												
117	Total Annual amortization amount (L111/2)												

[1] Based on lag time assumptions noted on Page 6
- distribution plant, January based on 2018 capital spend. February - December based on monthly amount from Page 6 [A]
- transmission plant, January - June based on 2018 capital spend. July - December based on monthly amount from Page 6 [B]
- communication plant, January - March based on 2018 capital spend. April - December based on monthly amount from Page 6 [C]
- Advance DMS and Enterprise Systems annual amounts amount from Page 6 [D] placed in service in December.

[2] Per accounting.
[3] From Bateman Exhibit 4 page 6.
[4] From Bateman exhibit 4 page 7, lines 3 and 4.

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 1
For the period January 1, 2019 through December 31, 2019

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 3

Line No.	Calculation of South Carolina Retail Costs Description	2020 Jan	2020 Feb	2020 Mar	2020 Apr	2020 May	Total
1	Plant-in-Service: [1]						
2	Distribution to Plant in Service						
3	Transmission to Plant in Service						
4	Advanced DMS Plant in Service						
5	Communications Plant in Service						
6	Enterprise Applications Plant in Service						
7	Cumulative Distribution investment (L2)	13,669,981	13,669,981	13,669,981	13,669,981	13,669,981	
8	Cumulative Transmission investment (L3)	4,865,943	4,865,943	4,865,943	4,865,943	4,865,943	
9	Cumulative Advanced DMS investment (L4)	879,434	879,434	879,434	879,434	879,434	
10	Cumulative Communication investment (L5)	2,436,016	2,436,016	2,436,016	2,436,016	2,436,016	
11	Cumulative Enterprise Application investment (L6)	1,186,120	1,186,120	1,186,120	1,186,120	1,186,120	
12							
13	Accumulated depreciation & amortization:						
14	Distribution plant depreciation rate [2]	2.43%	2.43%	2.43%	2.43%	2.43%	
15	Transmission plant depreciation rate [2]	1.91%	1.91%	1.91%	1.91%	1.91%	
16	Advance DMS plant depreciation rate [2]	10.00%	10.00%	10.00%	10.00%	10.00%	
17	Communication plant depreciation rate [2]	5.00%	5.00%	5.00%	5.00%	5.00%	
18	Enterprise Application plant depreciation rate [2]	20.00%	20.00%	20.00%	20.00%	20.00%	
19	Distribution depreciation expense (L7 * L14)	27,682	27,682	27,682	27,682	27,682	
20	Transmission depreciation expense (L8 * L15)	7,745	7,745	7,745	7,745	7,745	
21	Advanced DMS depreciation expense (L9 * L16)	7,329	7,329	7,329	7,329	7,329	
22	Communication depreciation expense (L10 * L17)	10,150	10,150	10,150	10,150	10,150	
23	Enterprise Application depreciation expense (L11 * L18)	19,769	19,769	19,769	19,769	19,769	
24	Distribution accumulated depreciation	(181,725)	(209,406)	(237,088)	(264,770)	(292,452)	
25	Transmission accumulated depreciation	(61,332)	(69,077)	(76,822)	(84,567)	(92,312)	
26	Advanced DMS accumulated depreciation	(7,329)	(14,657)	(21,986)	(29,314)	(36,643)	
27	Communication accumulated depreciation	(67,091)	(77,241)	(87,391)	(97,541)	(107,691)	
28	Enterprise Application accumulated depreciation	(19,769)	(39,537)	(59,306)	(79,075)	(98,843)	
29							
30	Net electric plant						
31	Distribution (L7 + L24)	13,488,257	13,460,575	13,432,893	13,405,212	13,377,530	
32	Transmission (L8 + L25)	4,804,610	4,796,866	4,789,121	4,781,376	4,773,631	
33	Advanced DMS (L9 + L26)	872,105	864,776	857,448	850,119	842,791	
34	Communication (L10 + L27)	2,368,925	2,358,775	2,348,625	2,338,475	2,328,325	
35	Enterprise Application (L11 + L28)	1,166,351	1,146,583	1,126,814	1,107,045	1,087,277	
36	Average rate base - Distribution	13,502,097	13,474,416	13,446,734	13,419,052	13,391,371	
37	Average rate base - Transmission	4,808,483	4,800,738	4,792,993	4,785,248	4,777,503	
38	Average rate base - Advanced DMS	875,769	868,441	861,112	853,784	846,455	
39	Average rate base - Communication	2,374,000	2,363,850	2,353,700	2,343,550	2,333,400	
40	Average rate base - Enterprise Application	1,176,236	1,156,467	1,136,698	1,116,930	1,097,161	
41							

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 65 of 78

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 66 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 1
For the period January 1, 2019 through December 31, 2019

Line No.	Calculation of South Carolina Retail Costs	2020 Jan	2020 Feb	2020 Mar	2020 Apr	2020 May	Total
42	Return on rate base:						
43	Long-term debt [4]	1.908%	1.908%	1.908%	1.908%	1.908%	
44	Members' equity [4]	7.415%	7.415%	7.415%	7.415%	7.415%	
45	Distribution Debt return on rate base (L36 x L43 / 12)	21,471	21,427	21,383	21,339	21,295	237,798
46	Transmission Debt return on rate base (L37 x L43 / 12)	7,646	7,634	7,622	7,609	7,597	95,176
47	Advance DMS Debt return on rate base (L38 x L43 / 12)	1,393	1,381	1,369	1,358	1,346	7,546
48	Communication Debt return on rate base (L39 x L43 / 12)	3,775	3,759	3,743	3,727	3,710	42,029
49	Enterprise Application Debt return on rate base (L40 x L43 / 12)	1,870	1,839	1,808	1,776	1,745	9,981
50	Distribution Equity return on rate base (L36 x L44 / 12)	83,432	83,261	83,090	82,919	82,748	924,057
51	Transmission Equity return on rate base (L37 x L44 / 12)	29,713	29,665	29,617	29,569	29,521	369,845
52	Advance DMS Equity return on rate base (L38 x L44 / 12)	5,412	5,366	5,321	5,276	5,230	29,322
53	Communication Equity return on rate base (L39 x L44 / 12)	14,669	14,607	14,544	14,481	14,419	163,321
54	Enterprise Application Equity return on rate base (L40 x L44 / 12)	7,268	7,146	7,024	6,902	6,780	38,784
55							
56	Other operation and maintenance expense: [3]						
57	Distribution O&M						346,883
58	Transmission O&M						16,828
59	General Plant O&M						739,840
60	Total O&M	-	-	-	-	-	1,103,551
61							
62	Depreciation and amortization:						
63	Distribution depreciation expense (L19)	27,682	27,682	27,682	27,682	27,682	292,452
64	Transmission depreciation expense (L20)	7,745	7,745	7,745	7,745	7,745	92,312
65	General Plant depreciation expense (Sum(L21: L23))	37,247	37,247	37,247	37,247	37,247	243,177
66	Total Depreciation	72,674	72,674	72,674	72,674	72,674	627,941
67							
68	General taxes:						
69	Property tax rate - South Carolina	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%
70	Property tax rate - Combined North Carolina and South Carolina	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%
71							
72	Distribution property tax expense	15,452	15,452	15,452	15,452	15,452	77,261
73	Transmission property tax expense	1,547	1,547	1,547	1,547	1,547	7,735
74	General Plant property tax expense	1,431	1,431	1,431	1,431	1,431	7,156
75	Impact to general taxes (Sum (L72:L74)	18,430	18,430	18,430	18,430	18,430	92,152
76							
77	Total impact to operating income:						
78	Distribution (L57 + L63 + L72)	43,134	43,134	43,134	43,134	43,134	716,596
79	Transmission (L58 + L64 + L73)	9,292	9,292	9,292	9,292	9,292	116,876
80	General Plant (L59 + L65 + L74)	38,679	38,679	38,679	38,679	38,679	990,173
81							
82	Amount for Deferral:						
83	Distribution impact to operating income (L45 + L50 + L78)	148,037	147,822	147,607	147,392	147,177	1,878,451
84	Transmission impact to operating income (L46 + L51 + L79)	46,651	46,591	46,531	46,470	46,410	581,897
85	General plant impact to operating income (sum(L47:49) + sum(L52:54) + L80)	73,066	72,776	72,487	72,198	71,908	1,281,156
86	Total	267,754	267,189	266,624	266,060	265,495	3,741,504
87	Distribution Cumulative amount for deferral	1,319,741	1,474,827	1,630,602	1,787,071	1,944,239	
88	Transmission Cumulative amount for deferral	404,689	453,503	502,542	551,807	601,300	
89	General Plant Cumulative amount for deferral	1,022,300	1,100,824	1,179,518	1,258,382	1,337,418	
90							
91	Balance for return						
92	Distribution Balance for Return (Prior Month L89 + Current Month L89 /2)	1,245,723	1,400,916	1,556,799	1,713,375	1,870,650	
93	Transmission Balance for Return (Prior Month L90 + Current Month L90 /2)	381,363	430,208	479,277	528,572	578,094	
94	General Plant Balance for Return (Prior Month L90 + Current Month L90 /2)	985,767	1,064,436	1,143,275	1,222,283	1,301,463	
95							

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 1
For the period January 1, 2019 through December 31, 2019

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 3

Line No.	Calculation of South Carolina Retail Costs Description	2020 Jan	2020 Feb	2020 Mar	2020 Apr	2020 May	Total
96	Return on Deferred Balance						
97	After Tax Long-term debt [4]	1.432%	1.432%	1.432%	1.432%	1.432%	
98	After Tax Members' equity [4]	5.565%	5.565%	5.565%	5.565%	5.565%	
99	Distribution Debt Return on Deferral (L92 * L97/12)	1,487	1,672	1,858	2,045	2,232	15,697
100	Transmission Debt Return on Deferral (L93 * L97/12)	455	513	572	631	690	4,661
101	General Plant Debt Return on Deferral (L94 * L97/12)	1,176	1,270	1,364	1,459	1,553	13,068
102	Distribution Equity Return on Deferral (L92 * L98/12)	5,777	6,497	7,220	7,946	8,675	60,998
103	Transmission Equity Return on Deferral (L93 * L98/12)	1,769	1,995	2,223	2,451	2,681	18,112
104	General Plant Equity Return on Deferral (L94 * L98/12)	4,572	4,936	5,302	5,668	6,036	50,782
105	Total (Sum L99:L104)	15,235	16,884	18,539	20,200	21,867	163,319
106							
107	Total Deferred balance						
108	Distribution deferral (L83 + L99 + L102)	155,301	155,990	156,684	157,382	158,084	1,955,146
109	Transmission deferral (L84 + L100 + L103)	48,875	49,099	49,325	49,552	49,781	604,670
110	General Plant deferral (L85 + L101 + L104)	78,814	78,983	79,153	79,325	79,497	1,345,006
111	Total Sum (L108:L110)	282,989	284,073	285,163	286,259	287,362	3,904,823
112							
113	Annual Amortization						
114	Distribution amortization amount (L108/2)						977,573
115	Transmission amortization amount (L109/2)						302,335
116	General Plant amortization amount (L110/2)						672,503
117	Total Annual amortization amount (L111/2)						1,952,411

[1] Based on lag time assumptions noted on Page 6
- distribution plant, January based on 2018 capital spend. February - December base
- transmission plant, January - June based on 2018 capital spend. July - December ba
- communication plant, January - March based on 2018 capital spend. April - Decem
- Advance DMS and Enterprise Systems annual amounts amount from Page 6 [D] pla

[2] Per accounting.
[3] From Bateman Exhibit 4 page 6.
[4] From Bateman exhibit 4 page 7, lines 3 and 4.

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 67 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE I
REVENUE REQUIREMENT
For the period January 1, 2020 through December 31, 2020

Line No.	Description		Total SC Retail	Depreciation Rate	Depreciation
1	Impact to Rate Base Line Items				
2	Additions to gross electric plant:				
3	Distribution [1]		$ 21,773,026	2.43%	$ 529,085
4	Transmission [1]		4,961,227	1.91%	94,759
5	General - Advanced DMS [1]		1,096,228	10.00%	109,623
6	General - Communication [1]		5,905,312	5.00%	295,266
7	General - Enterprise Applications [1]		1,637,858	20.00%	327,572
8	Impact to electric plant in service (Sum L3 through L7)		$ 35,373,651		$ 1,356,304
9					
10	Accumulated depreciation & amortization:				
11	Distribution accumulated depreciation (-L3)		$ (529,085)		
12	Transmission accumulated depreciation (-L4)		(94,759)		
13	General Plant accumulated depreciation (-Sum L5 through L7)		(732,460)		
14	Impact to accumulated depreciation (Sum L11 through L13)		$ (1,356,304)		
15					
16	Net electric plant:				
17	Distribution (L3 + L11)		$ 21,243,941		
18	Transmission (L4 + L12)		4,866,467		
19	General Plant (L5 + L6 + L7 + L13)		7,906,938		
20	Impact to net plant (Sum L17 through L19)		$ 34,017,347		
21					
22	Cost of Capital [2]	9.36%			
23					
24	Rate Base Revenue Requirement				
25	Distribution (L17 * L22)		$ 1,989,441		
26	Transmission (L18 * L22)		455,732		
27	General Plant (L19 * L22)		740,464		
28	Impact to net plant (Sum L25 through L27)		$ 3,185,637		
29					
30	Impact to Income Statement Line Items				
31	Depreciation and amortization:				
32	Distribution depreciation expense (L3)		$ 529,085		
33	Transmission depreciation expense (L4)		94,759		
34	General Plant depreciation expense (Sum L5 through L7)		732,460		
35	Impact to deprec. and amortization (Sum L32 through L34)		$ 1,356,304		
36					
37	Removal of expired amortization of 2018 deferral:				
38	Distribution depreciation expense		$ (1,145,261)		
39	Transmission depreciation expense		(121,947)		
40	General Plant depreciation expense		(805,394)		
41	Impact to deprec. and amortization (Sum L38 through L40)		$ (2,072,602)		

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE I
REVENUE REQUIREMENT
For the period January 1, 2020 through December 31, 2020

Line No.	Description		Total SC Retail
42			
43	Amortization of 2019 deferral:		
44	Distribution depreciation expense		
45	Transmission depreciation expense		
46	General Plant depreciation expense		
47	Impact to deprec. and amortization (Sum L44 through L46)		$ -
48			
49	Amortization of 2020 deferral:		
50	Distribution depreciation expense [3]		$ 1,534,505
51	Transmission depreciation expense [3]		273,470
52	General Plant depreciation expense [3]		1,152,661
53	Impact to deprec. and amortization (Sum L50 through L52)		$ 2,960,636
54			
55	General taxes:		
56	Property tax rate - South Carolina	1.3565%	
57	Property tax rate - Combined North Carolina and South Carolina	0.3815%	
58			
59	Distribution property tax expense (L3 * L56)		$ 295,341
60	Transmission property tax expense (L4 * L57)		18,928
61	General Plant property tax expense (Sum(L5 through L7) * L57)		32,961
62	Impact to general taxes (Sum L59 through L61)		$ 347,230
63			
64	Income Taxes	24.95%	
65	Distribution (L32 + L38 + L44 + L50 + L59) * -L64		$ (302,810)
66	Transmission (L33 + L39 + L45 + L51 + L60) * -L64		(66,170)
67	General Plant (L34 + L40 + L46 + L52 + L61) * -L64		(277,616)
68	Total income taxes (Sum L65 through L67)		$ (646,596)
69			
70	Total Income statement impact		
71	Distribution (L32 + L38 + L44 + L50 + L59 + L65)		$ 910,859
72	Transmission (L33 + L39 + L45 + L51 + L60 + L66)		199,041
73	General Plant (L34 + L40 + L46 + L52 + L61 + L67)		835,072
74	Total income statement impact (Sum L71 through L73)		$ 1,944,972
75			
76	Income Statement Requirement	74.72% [4]	
77	Distribution (L71 / L76)		$ 1,219,070
78	Transmission (L72 / L76)		266,391
79	General Plant (L73 / L76)		1,117,639
80	Total income statement Requirement (Sum L77 through L79)		$ 2,603,100

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 69 of 78

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 70 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
DUKE ENERGY PROGRESS, LLC
REVENUE REQUIREMENT
For the period January 1, 2020 through December 31, 2020

Line No.	Description	Total SC Retail
81		
82	Total Revenue Requirement for Plant additions and Deferral	
83	Distribution (L25 + L77)	$ 3,208,510
84	Transmission (L26 + L78)	722,123
85	General Plant (L27 + L79)	1,858,104
86	Total Revenue Requirement (Sum L83 through L85)	$ 5,788,737

[1] Bateman Exhibit 4 page 5, lines 7-11 May, 2021.
[2] Bateman Exhibit 4 page 7, line 5.
[3] Bateman Exhibit 4 page 5, lines 114-116
[4] Bateman Exhibit 4 page 7, line 24.

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 71 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 2
For the period January 1, 2020 through December 31, 2020

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 5

Line No.	Calculation of South Carolina Retail Costs	2020 Jan	2020 Feb	2020 Mar	2020 Apr	2020 May	2020 Jun	2020 Jul	2020 Aug	2020 Sep	2020 Oct	2020 Nov	2020 Dec
1	Plant-in-Service: [1]												
2	Distribution to Plant in Service	1,125,745	1,877,025	1,877,025	1,877,025	1,877,025	1,877,025	1,877,025	1,877,025	1,877,025	1,877,025	1,877,025	1,877,025
3	Transmission to Plant in Service	145,772	145,772	145,772	145,772	145,772	145,772	681,100	681,100	681,100	681,100	681,100	681,100
4	Advanced DMS Plant in Service												1,096,228
5	Communications Plant in Service	198,224	198,224	198,224	590,071	590,071	590,071	590,071	590,071	590,071	590,071	590,071	590,071
6	Enterprise Applications Plant in Service	-	-	-	-	-	-	-	-	-	-	-	1,637,858
7	Cumulative Distribution investment (L2)	1,125,745	3,002,771	4,879,796	6,756,822	8,633,847	10,510,873	12,387,898	14,264,924	16,141,949	18,018,975	19,896,000	21,773,026
8	Cumulative Transmission investment (L3)	145,772	291,543	437,315	583,086	728,858	874,629	1,555,729	2,236,828	2,917,928	3,599,028	4,280,127	4,961,227
9	Cumulative Advanced DMS investment (L4)												1,096,228
10	Cumulative Communication investment (L5)	198,224	396,448	594,672	1,184,743	1,774,814	2,364,885	2,954,956	3,545,027	4,135,099	4,725,170	5,315,241	5,905,312
11	Cumulative Enterprise Application investment (L6)	-	-	-	-	-	-	-	-	-	-	-	1,637,858
12													
13	Accumulated depreciation & amortization:												
14	Distribution plant depreciation rate [2]	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%
15	Transmission plant depreciation rate [2]	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%
16	Advance DMS plant depreciation rate [2]	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
17	Communication plant depreciation rate [2]	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
18	Enterprise Application plant depreciation rate [2]	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
19	Distribution depreciation expense (L7 * L14)	-	2,280	6,081	9,882	13,683	17,484	21,285	25,085	28,886	32,687	36,488	40,289
20	Transmission depreciation expense (L8 * L15)	-	232	464	696	928	1,160	1,392	2,476	3,560	4,644	5,728	6,813
21	Advanced DMS depreciation expense (L9 * L16)	-	-	-	-	-	-	-	-	-	-	-	-
22	Communication depreciation expense (L10 * L17)	-	826	1,652	2,478	4,936	7,395	9,854	12,312	14,771	17,230	19,688	22,147
23	Enterprise Application depreciation expense (L11 * L18)	-	-	-	-	-	-	-	-	-	-	-	-
24	Distribution accumulated depreciation	-	(2,280)	(8,360)	(18,242)	(31,924)	(49,408)	(70,692)	(95,778)	(124,664)	(157,352)	(193,840)	(234,130)
25	Transmission accumulated depreciation	-	(232)	(696)	(1,392)	(2,320)	(3,480)	(4,872)	(7,349)	(10,909)	(15,553)	(21,282)	(28,094)
26	Advanced DMS accumulated depreciation	-	-	-	-	-	-	-	-	-	-	-	-
27	Communication accumulated depreciation	-	(826)	(2,478)	(4,956)	(9,892)	(17,287)	(27,141)	(39,453)	(54,224)	(71,454)	(91,142)	(113,289)
28	Enterprise Application accumulated depreciation	-	-	-	-	-	-	-	-	-	-	-	-
29													
30	Net electric plant												
31	Distribution (L7 + L24)	1,125,745	3,000,491	4,871,436	6,738,580	8,601,923	10,461,465	12,317,206	14,169,146	16,017,285	17,861,623	19,702,160	21,538,896
32	Transmission (L8 + L25)	145,772	291,311	436,619	581,694	726,538	871,149	1,550,856	2,229,480	2,907,019	3,583,474	4,258,845	4,933,132
33	Advanced DMS (L9 + L26)	-	-	-	-	-	-	-	-	-	-	-	1,096,228
34	Communication (L10 + L27)	198,224	395,622	592,194	1,179,787	1,764,922	2,347,598	2,927,815	3,505,574	4,080,875	4,653,716	5,224,099	5,792,023
35	Enterprise Application (L11 + L28)	-	-	-	-	-	-	-	-	-	-	-	1,637,858
36	Average rate base - Distribution	562,873	2,063,118	3,935,963	5,805,008	7,670,251	9,531,694	11,389,335	13,243,176	15,093,215	16,939,454	18,781,891	20,620,528
37	Average rate base - Transmission	72,886	218,541	363,965	509,156	654,116	798,843	1,211,003	1,890,168	2,568,249	3,245,247	3,921,160	4,595,989
38	Average rate base - Advanced DMS	-	-	-	-	-	-	-	-	-	-	-	548,114
39	Average rate base - Communication	99,112	296,923	493,908	885,990	1,472,355	2,056,260	2,637,707	3,216,695	3,793,224	4,367,295	4,938,908	5,508,061
40	Average rate base - Enterprise Application	-	-	-	-	-	-	-	-	-	-	-	818,929
41													
42	Return on rate base:												
43	Long-term debt [4]	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%	1.908%
44	Members' equity [4]	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%	7.415%
45	Distribution Debt return on rate base (L36 x L43 / 12)	895	3,281	6,259	9,231	12,197	15,157	18,111	21,059	24,001	26,937	29,866	32,790
46	Transmission Debt return on rate base (L37 x L43 / 12)	116	348	579	810	1,040	1,270	1,926	3,006	4,084	5,160	6,235	7,308
47	Advance DMS Debt return on rate base (L38 x L43 / 12)	-	-	-	-	-	-	-	-	-	-	-	872
48	Communication Debt return on rate base (L39 x L43 / 12)	158	472	785	1,409	2,341	3,270	4,194	5,115	6,032	6,945	7,854	8,759
49	Enterprise Application Debt return on rate base (L40 x L43 / 12)	-	-	-	-	-	-	-	-	-	-	-	1,302
50	Distribution Equity return on rate base (L36 x L44 / 12)	3,478	12,748	24,321	35,870	47,396	58,898	70,377	81,832	93,264	104,673	116,057	127,419
51	Transmission Equity return on rate base (L37 x L44 / 12)	450	1,350	2,249	3,146	4,042	4,936	7,483	11,680	15,870	20,053	24,230	28,400
52	Advance DMS Equity return on rate base (L38 x L44 / 12)	-	-	-	-	-	-	-	-	-	-	-	3,387
53	Communication Equity return on rate base (L39 x L44 / 12)	612	1,835	3,052	5,475	9,098	12,706	16,299	19,877	23,439	26,986	30,519	34,035

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 72 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 2
For the period January 1, 2020 through December 31, 2020

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 5

Line No.	Calculation of South Carolina Retail Costs Description	2020 Jan	2020 Feb	2020 Mar	2020 Apr	2020 May	2020 Jun	2020 Jul	2020 Aug	2020 Sep	2020 Oct	2020 Nov	2020 Dec
54	Enterprise Application Equity return on rate base (L40 x L44 / 12)	-	-	-	-	-	-	-	-	-	-	-	5,060
55													
56	Other operation and maintenance expense: [3]												
57	Distribution O&M	46,998	46,998	46,998	46,998	46,998	46,998	46,998	46,998	46,998	46,998	46,998	46,998
58	Transmission O&M	8,793	8,793	8,793	8,793	8,793	8,793	8,793	8,793	8,793	8,793	8,793	8,793
59	General Plant O&M	99,939	99,939	99,939	99,939	99,939	99,939	99,939	99,939	99,939	99,939	99,939	99,939
60	Total O&M	155,731	155,731	155,731	155,731	155,731	155,731	155,731	155,731	155,731	155,731	155,731	155,731
61													
62	Depreciation and amortization:												
63	Distribution depreciation expense (L19)	-	2,280	6,081	9,882	13,683	17,484	21,285	25,085	28,886	32,687	36,488	40,289
64	Transmission depreciation expense (L20)	-	232	464	696	928	1,160	1,392	2,476	3,560	4,644	5,728	6,813
65	General Plant depreciation expense (Sum(L21: L23))	-	826	1,652	2,478	4,936	7,395	9,854	12,312	14,771	17,230	19,688	22,147
66	General Plant O&M	-	3,338	8,197	13,055	19,547	26,039	32,530	39,874	47,218	54,561	61,905	69,249
67													
68	General taxes:												
69	Property tax rate - South Carolina	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%
70	Property tax rate - Combined North Carolina and South Carolina	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%
71													
72	Distribution property tax expense												
73	Transmission property tax expense												
74	General Plant property tax expense												
75	Impact to general taxes (Sum (L72:L74))	-	-	-	-	-	-	-	-	-	-	-	-
76													
77	Total impact to operating income:												
78	Distribution (L57 + L63 + L72)	46,998	49,278	53,079	56,880	60,681	64,482	68,283	72,084	75,884	79,685	83,486	87,287
79	Transmission (L58 + L64 + L73)	8,793	9,025	9,257	9,489	9,721	9,953	10,185	11,269	12,354	13,438	14,522	15,606
80	General Plant (L59 + L65 + L74)	99,939	100,765	101,591	102,417	104,876	107,334	109,793	112,252	114,710	117,169	119,627	122,086
81													
82	Total impact to operating income:												
83	Distribution impact to operating income (L45 + L50 + L78)	51,371	65,307	83,659	101,981	120,274	138,537	156,771	174,975	193,149	211,295	229,410	247,496
84	Transmission impact to operating income (L46 + L51 + L79)	9,360	10,723	12,085	13,445	14,803	16,160	19,594	25,955	32,307	38,651	44,987	51,314
85	General plant impact to operating income (sum(L47:49) + sum(L52:54) + L80)	100,709	103,072	105,428	109,301	116,315	123,310	130,286	137,243	144,181	151,100	158,000	175,501
86	Total	161,440	179,102	201,172	224,727	251,392	278,007	306,651	338,173	369,638	401,046	432,396	474,311
87	Distribution Cumulative amount for deferral	51,371	116,828	200,977	303,886	425,634	566,303	725,971	904,722	1,102,637	1,319,798	1,556,287	1,812,189
88	Transmission Cumulative amount for deferral	9,360	20,110	32,281	45,879	60,911	77,383	97,381	123,847	156,800	196,272	242,290	294,886
89	General Plant Cumulative amount for deferral	100,709	204,075	310,393	421,196	539,648	665,766	799,575	941,100	1,090,369	1,247,406	1,412,239	1,595,514
90													
91	Balance for return												
92	Distribution Balance for Return (Prior Month L89 + Current Month L89 /2)	25,686	84,174	159,148	252,896	365,498	497,034	647,586	817,235	1,006,062	1,214,150	1,441,582	1,688,441
93	Transmission Balance for Return (Prior Month L90 + Current Month L90 /2)	4,680	14,748	26,239	39,157	53,509	69,303	87,584	110,869	140,647	176,946	219,797	269,229
94	General Plant Balance for Return (Prior Month L90 + Current Month L90 /2)	50,355	152,539	257,679	366,546	481,491	604,111	734,432	872,479	1,018,278	1,171,856	1,333,239	1,507,764
95													
96	Return on Deferred Balance												
97	After Tax Long-term debt [4]	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%
98	After Tax Members' equity [4]	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%	5.565%
99	Distribution Debt Return on Deferral (L92 * L97/12)	31	100	190	302	436	593	773	975	1,201	1,449	1,720	2,015
100	Transmission Debt Return on Deferral (L93 * L97/12)	6	18	31	47	64	83	105	132	168	211	262	321
101	General Plant Debt Return on Deferral (L94 * L97/12)	60	182	308	437	575	721	876	1,041	1,215	1,399	1,591	1,799
102	Distribution Equity Return on Deferral (L92 * L98/12)	119	390	738	1,173	1,695	2,305	3,003	3,790	4,666	5,631	6,685	7,830
103	Transmission Equity Return on Deferral (L93 * L98/12)	22	68	122	182	248	321	406	514	652	821	1,019	1,249
104	General Plant Equity Return on Deferral (L94 * L98/12)	234	707	1,195	1,700	2,233	2,802	3,406	4,046	4,722	5,434	6,183	6,992
105	Total (Sum L99:L104)	471	1,466	2,583	3,840	5,251	6,825	8,569	10,499	12,624	14,944	17,461	20,207
106													

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 2
For the period January 1, 2020 through December 31, 2020

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 5

Line No.	Calculation of South Carolina Retail Costs	2020 Jan	2020 Feb	2020 Mar	2020 Apr	2020 May	2020 Jun	2020 Jul	2020 Aug	2020 Sep	2020 Oct	2020 Nov	2020 Dec
107	Total												
108	Distribution deferral (L83 + L99 + L102)	51,521	65,798	84,587	103,456	122,405	141,435	160,547	179,740	199,016	218,374	237,816	257,341
109	Transmission deferral (L84 + L100 + L103)	9,387	10,809	12,238	13,673	15,115	16,564	20,105	26,601	33,127	39,683	46,268	52,884
110	General Plant deferral (L85 + L101 + L104)	101,003	103,961	106,931	111,438	119,122	126,833	134,569	142,331	150,119	157,933	165,774	184,293
111	Total Sum (L108:L110)	161,911	180,568	203,756	228,567	256,643	284,832	315,220	348,672	382,262	415,990	449,858	494,518
112													
113	Annual Amortization												
114	Distribution amortization amount (L108/2)												
115	Transmission amortization amount (L109/2)												
116	General Plant amortization amount (L110/2)												
117	Total Annual amortization amount (L111/2)												

[1] Based on lag time assumptions noted on Page 6
- distribution plant, January based on 2018 capital spend. February - December based on monthly amount from Page 6 [A]
- transmission plant, January - June based on 2018 capital spend. July - December based on monthly amount from Page 6 [B]
- communication plant, January - March based on 2018 capital spend. April - December based on monthly amount from Page 6 [C]
- Advance DMS and Enterprise Systems annual amounts amount from Page 6 [D] placed in service in December.

[2] Per accounting

[3] From Bateman exhibit 4 page 6.

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 74 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 2
For the period January 1, 2020 through December 31, 2020

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 5

Line No.	Calculation of South Carolina Retail Costs Description	2021 Jan	2021 Feb	2021 Mar	2021 Apr	2021 May	Total
1	Plant-in-Service: [1]						
2	Distribution to Plant in Service						
3	Transmission to Plant in Service						
4	Advanced DMS Plant in Service						
5	Communications Plant in Service						
6	Enterprise Applications Plant in Service						
7	Cumulative Distribution investment (L2)	21,773,026	21,773,026	21,773,026	21,773,026	21,773,026	
8	Cumulative Transmission investment (L3)	4,961,227	4,961,227	4,961,227	4,961,227	4,961,227	
9	Cumulative Advanced DMS investment (L4)	1,096,228	1,096,228	1,096,228	1,096,228	1,096,228	
10	Cumulative Communication investment (L5)	5,905,312	5,905,312	5,905,312	5,905,312	5,905,312	
11	Cumulative Enterprise Application investment (L6)	1,637,858	1,637,858	1,637,858	1,637,858	1,637,858	
12							
13	Accumulated depreciation & amortization:						
14	Distribution plant depreciation rate [2]	2.43%	2.43%	2.43%	2.43%	2.43%	
15	Transmission plant depreciation rate [2]	1.91%	1.91%	1.91%	1.91%	1.91%	
16	Advance DMS plant depreciation rate [2]	10.00%	10.00%	10.00%	10.00%	10.00%	
17	Communication plant depreciation rate [2]	5.00%	5.00%	5.00%	5.00%	5.00%	
18	Enterprise Application plant depreciation rate [2]	20.00%	20.00%	20.00%	20.00%	20.00%	
19	Distribution depreciation expense (L7 * L14)	44,090	44,090	44,090	44,090	44,090	
20	Transmission depreciation expense (L8 * L15)	7,897	7,897	7,897	7,897	7,897	
21	Advanced DMS depreciation expense (L9 * L16)	9,135	9,135	9,135	9,135	9,135	
22	Communication depreciation expense (L10 * L17)	24,605	24,605	24,605	24,605	24,605	
23	Enterprise Application depreciation expense (L11 * L18)	27,298	27,298	27,298	27,298	27,298	
24	Distribution accumulated depreciation	(278,220)	(322,310)	(366,401)	(410,491)	(454,582)	
25	Transmission accumulated depreciation	(35,991)	(43,888)	(51,784)	(59,681)	(67,577)	
26	Advanced DMS accumulated depreciation	(9,135)	(18,270)	(27,406)	(36,541)	(45,676)	
27	Communication accumulated depreciation	(137,894)	(162,500)	(187,105)	(211,711)	(236,316)	
28	Enterprise Application accumulated depreciation	(27,298)	(54,595)	(81,893)	(109,191)	(136,488)	
29							
30	Net electric plant						
31	Distribution (L7 + L24)	21,494,805	21,450,715	21,406,625	21,362,534	21,318,444	
32	Transmission (L8 + L25)	4,925,236	4,917,339	4,909,442	4,901,546	4,893,649	
33	Advanced DMS (L9 + L26)	1,087,093	1,077,958	1,068,823	1,059,687	1,050,552	
34	Communication (L10 + L27)	5,767,418	5,742,812	5,718,207	5,693,602	5,668,996	
35	Enterprise Application (L11 + L28)	1,610,560	1,583,263	1,555,965	1,528,667	1,501,370	
36	Average rate base - Distribution	21,516,851	21,472,760	21,428,670	21,384,580	21,340,489	
37	Average rate base - Transmission	4,929,184	4,921,287	4,913,391	4,905,494	4,897,598	
38	Average rate base - Advanced DMS	1,091,661	1,082,526	1,073,390	1,064,255	1,055,120	
39	Average rate base - Communication	5,779,721	5,755,115	5,730,510	5,705,904	5,681,299	
40	Average rate base - Enterprise Application	1,624,209	1,596,911	1,569,614	1,542,316	1,515,019	
41							
42	Return on rate base:						
43	Long-term debt [4]	1.908%	1.908%	1.908%	1.908%	1.908%	
44	Members' equity [4]	7.415%	7.415%	7.415%	7.415%	7.415%	
45	Distribution Debt return on rate base (L36 x L43 / 12)	34,215	34,145	34,075	34,005	33,935	370,159
46	Transmission Debt return on rate base (L37 x L43 / 12)	7,838	7,826	7,813	7,801	7,788	70,947
47	Advance DMS Debt return on rate base (L38 x L43 / 12)	1,736	1,721	1,707	1,692	1,678	9,406
48	Communication Debt return on rate base (L39 x L43 / 12)	9,191	9,152	9,112	9,073	9,034	92,896
49	Enterprise Application Debt return on rate base (L40 x L43 / 12)	2,583	2,539	2,496	2,453	2,409	13,782
50	Distribution Equity return on rate base (L36 x L44 / 12)	132,957	132,685	132,412	132,140	131,867	1,438,397
51	Transmission Equity return on rate base (L37 x L44 / 12)	30,458	30,410	30,361	30,312	30,263	275,694
52	Advance DMS Equity return on rate base (L38 x L44 / 12)	6,746	6,689	6,633	6,576	6,520	36,550
53	Communication Equity return on rate base (L39 x L44 / 12)	35,714	35,562	35,410	35,258	35,106	360,983

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 2
For the period January 1, 2020 through December 31, 2020

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 5

Line No.	Calculation of South Carolina Retail Costs Description	2021 Jan	2021 Feb	2021 Mar	2021 Apr	2021 May	Total
54	Enterprise Application Equity return on rate base (L40 x L44 / 12)	10,036	9,868	9,699	9,530	9,362	53,555
55							
56	Other operation and maintenance expense: [3]						
57	Distribution O&M						563,976
58	Transmission O&M						105,519
59	General Plant O&M						1,199,271
60	Total O&M	-	-	-	-	-	1,868,766
61							
62	Depreciation and amortization:						
63	Distribution depreciation expense (L19)	44,090	44,090	44,090	44,090	44,090	454,582
64	Transmission depreciation expense (L20)	7,897	7,897	7,897	7,897	7,897	67,577
65	General Plant depreciation expense (Sum(L21: L23))	61,038	61,038	61,038	61,038	61,038	418,480
66	General Plant O&M	113,025	113,025	113,025	113,025	113,025	940,639
67							
68	General taxes:						
69	Property tax rate - South Carolina	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%
70	Property tax rate - Combined North Carolina and South Carolina	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%
71							
72	Distribution property tax expense	24,612	24,612	24,612	24,612	24,612	123,059
73	Transmission property tax expense	1,577	1,577	1,577	1,577	1,577	7,887
74	General Plant property tax expense	2,747	2,747	2,747	2,747	2,747	13,734
75	Impact to general taxes (Sum (L72:L74))	28,936	28,936	28,936	28,936	28,936	144,679
76							
77	Total impact to operating income:						
78	Distribution (L57 + L63 + L72)	68,702	68,702	68,702	68,702	68,702	1,141,617
79	Transmission (L58 + L64 + L73)	9,474	9,474	9,474	9,474	9,474	180,983
80	General Plant (L59 + L65 + L74)	63,785	63,785	63,785	63,785	63,785	1,631,485
81							
82	Total impact to operating income:						
83	Distribution impact to operating income (L45 + L50 + L78)	235,875	235,532	235,190	234,847	234,505	2,950,172
84	Transmission impact to operating income (L46 + L51 + L79)	47,771	47,709	47,648	47,587	47,525	527,624
85	General plant impact to operating income (sum(L47:49) + sum(L52:54) + L80)	129,791	129,316	128,842	128,368	127,894	2,198,658
86	Total	413,436	412,558	411,680	410,802	409,923	5,676,454
87	Distribution Cumulative amount for deferral	2,057,909	2,304,753	2,552,695	2,801,741	3,051,898	
88	Transmission Cumulative amount for deferral	344,226	393,803	443,608	493,643	543,908	
89	General Plant Cumulative amount for deferral	1,734,097	1,873,146	2,012,533	2,152,260	2,292,329	
90							
91	Balance for return						
92	Distribution Balance for Return (Prior Month L89 + Current Month L89 /2)	1,939,972	2,186,987	2,435,100	2,684,317	2,934,645	
93	Transmission Balance for Return (Prior Month L90 + Current Month L90 /2)	320,341	369,949	419,784	469,849	520,145	
94	General Plant Balance for Return (Prior Month L90 + Current Month L90 /2)	1,669,201	1,808,488	1,948,112	2,088,076	2,228,382	
95							
96	Return on Deferred Balance						
97	After Tax Long-term debt [4]	1.432%	1.432%	1.432%	1.432%	1.432%	
98	After Tax Members' equity [4]	5.565%	5.565%	5.565%	5.565%	5.565%	
99	Distribution Debt Return on Deferral (L92 * L97/12)	2,315	2,610	2,906	3,204	3,502	24,323
100	Transmission Debt Return on Deferral (L93 * L97/12)	382	442	501	561	621	3,954
101	General Plant Debt Return on Deferral (L94 * L97/12)	1,992	2,158	2,325	2,492	2,659	21,831
102	Distribution Equity Return on Deferral (L92 * L98/12)	8,997	10,142	11,293	12,449	13,609	94,515
103	Transmission Equity Return on Deferral (L93 * L98/12)	1,486	1,716	1,947	2,179	2,412	15,363
104	General Plant Equity Return on Deferral (L94 * L98/12)	7,741	8,387	9,034	9,683	10,334	84,834
105	Total (Sum L99:L104)	22,913	25,454	28,006	30,567	33,138	244,819
106							

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 76 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN PHASE 2
For the period January 1, 2020 through December 31, 2020

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 5

Line No.	Calculation of South Carolina Retail Costs Description	2021 Jan	2021 Feb	2021 Mar	2021 Apr	2021 May	Total
107	Total						
108	Distribution deferral (L83 + L99 + L102)	247,187	248,284	249,389	250,499	251,616	3,069,009
109	Transmission deferral (L84 + L100 + L103)	49,639	49,866	50,096	50,326	50,558	546,941
110	General Plant deferral (L85 + L101 + L104)	139,524	139,861	140,201	140,543	140,887	2,305,323
111	Total Sum (L108:L110)	436,349	438,012	439,686	441,369	443,062	5,921,273
112							
113	Annual Amortization						
114	Distribution amortization amount (L108/2)						1,534,505
115	Transmission amortization amount (L109/2)						273,470
116	General Plant amortization amount (L110/2)						1,152,661
117	Total Annual amortization amount (L111/2)						2,960,636

[1] Based on lag time assumptions noted on Page 6
- distribution plant, January based on 2018 capital spend. February - December ba
- transmission plant, January - June based on 2018 capital spend. July - December
- communication plant, January - March based on 2018 capital spend. April - Dece
- Advance DMS and Enterprise Systems annual amounts amount from Page 6 [D] f

[2] Per accounting
[3] From Bateman exhibit 4 page 6.

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 77 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT
Capital Spend and Installation O&M Estimates
Dollars in Millions

	DEP Total Capital Spend			SC Retail	DEP Total Capital Spend				
	SYSTEM [1]	2019	2020	Allocation [2]	SC Retail	2019	2019 Monthly	2020	2020 Monthly
4	Energy Storage (NC Dist)	0.385	5.061		Energy Storage (NC Dist)				
5	Distribution NC	96.335	128.034		Distribution NC				
6	Energy Storage (SC Dist)	0.042	0.007	Direct	Energy Storage (SC Dist)	0.042	0.003	0.007	0.001
7	Distribution SC	13.467	22.518	Direct	Distribution SC	13.467	1.122	22.518	1.876
8	Total Distribution	110.228	155.620		Total Distribution [A]	13.509	1.126	22.524	1.877
10	Energy Storage (Trans)	0.427	5.068	9.31%	Energy Storage (Trans)	0.040	0.003	0.472	0.039
11	Transmission	18.365	82.732	9.31%	Transmission	1.710	0.142	7.701	0.642
12	Total Transmission	18.791	87.800		Total Transmission [B]	1.749	0.146	8.173	0.681
14	Advanced DMS	7.642	9.526	11.51%	Advanced DMS [D]	0.879	0.073	1.096	0.091
15	Communication	20.670	61.530	11.51%	Communication [C]	2.379	0.198	7.081	0.590
16	Enterprise Application	10.307	14.232	11.51%	Enterprise Application [D]	1.186	0.099	1.638	0.136
18	TOTAL	167.638	328.708		TOTAL	19.702	1.642	40.512	3.376

	Plant in Service Assumptions [1]	Lag between Capital Spend and asset in service
21	Distribution	1 month
22	Transmission	6 months
23	Communication	3 months
24	Advanced DMS & Enterprise Application	Annually in December

	DEP Total O&M			SC Retail	DEP Total O&M Spend				
	SYSTEM [1]	2019	2020	Allocation [2]	SC Retail	2019	2019 Monthly	2020	2020 Monthly
29	Energy Storage (NC Dist)	0.021	0.281		Energy Storage (NC Dist)				
30	Distribution NC	2.549	2.770		Distribution NC				
31	Energy Storage (SC Dist)	0.002	0.000	Direct	Energy Storage (SC Dist)	0.002	0.000	0.000	0.000
32	Distribution SC	0.345	0.564	Direct	Distribution SC	0.345	0.029	0.564	0.047
33	Total Distribution	2.917	3.615		Total Distribution	0.347	0.029	0.564	0.047
35	Energy Storage (Trans)	0.024	0.282	9.31%	Energy Storage (Trans)	0.002	0.000	0.026	0.002
36	Transmission	0.157	0.852	9.31%	Transmission	0.015	0.001	0.079	0.007
37	Total Transmission	0.181	1.134		Total Transmission	0.017	0.001	0.106	0.009
39	Advanced DMS	0.528	0.658	11.51%	Advanced DMS	0.061	0.005	0.076	0.006
40	Communication	1.012	3.012	11.51%	Communication	0.116	0.010	0.347	0.029
41	Enterprise Application	4.889	6.752	11.51%	Enterprise Application	0.563	0.047	0.777	0.065
43	TOTAL	9.527	15.170		TOTAL	1.104	0.092	1.869	0.156

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

ELECTRONICALLY FILED - 2018 November 8 10:16 AM - SCPSC - Docket # 2018-318-E - Page 78 of 78

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
SOUTH CAROLINA RETAIL GRID IMPROVEMENT PLAN

Bateman Exhibit 4
Calculation of SC Retail Costs
Page 7

Weighted Average Cost of Capital

Line No.	Description	Capital Structure (a)	Cost/ Return (b)	Weighted Cost/Return (c)	Income Taxes Factor (d)	After Tax Return (e)	Income Taxes Factor (f)	Revenue Requirement Excluding Gross Receipt Tax and Regulatory Fee (g)	Combined Gross Receipts Tax and Regulatory Fee Factor (h)	Revenue Requirement Including Gross Receipt Tax and Regulatory Fee (i)
1										
2										
3	Long-term debt	47.0000%	4.06%	1.9082%	0.7505000	1.43210%	1.00000	1.90820%	99.55699%	1.91669%
4	Members' equity	53.0000%	10.50%	5.5650%	1.0000000	5.56500%	0.75050	7.41506%	99.55699%	7.44805%
5	Total (L3 + L4)	100.0000%		7.4732%		6.9971%		9.3233%		9.3647%
6										
7	Gross revenue				1.0000000					
8	State income tax rate				0.0500000					
9	Remainder (L7 - L8)				0.9500000					
10	Federal income tax rate				0.2100000					
11	Federal income tax (L9 x L10)				0.1995000					
12	State income tax rate				0.0500000					
13	Combined income tax rate (L11 + L12)				0.2495000					
14	1 minus combined income tax rate (1 - L13)				0.7505000					
15										
16	Gross revenue				1.0000000					
17										
18	Gross receipts tax rate				0.0030000					
19	Regulatory fee rate				0.0014301					
20	Combined gross receipts tax and regulatory fee rate (L16 - L18 - L19)				0.9955699					
21	State income tax (L8 x L20)				0.0497785					
22	Balance (L20 - L21)				0.9457914					
23	Federal income tax (L10 x L22)				0.1986162					
24	Retention factor (L22 - L23)				0.7471752					

ELECTRONICALLY FILED - 2019 January 22 9:30 AM - SCPSC - Docket # 2018-318-E - Page 9 of 18

DUKE ENERGY PROGRESS, LLC
Supplemental Change to Op Income and Rate Base
FOR THE TEST PERIOD ENDED DECEMBER 31, 2017
(Thousands of Dollars)

Bateman Supplemental Exhibit 1

Description	Ref. # Bateman Exh 1	Change from Original Filing: Supplemental Change in Op Income	Change from Original Filing: Supplemental Change in Rate Base
Annualize Retail revenues for current rates	SC-0100		
Update fuel costs to approved rate and other fuel related adjustments	SC-0200		
Adjust Other Revenue	SC-0300		
OPEN	SC-0400		
Eliminate unbilled revenues	SC-0500		
Adjust for costs recovered through non-fuel riders	SC-0600		
OPEN	SC-0700		
Annualize Depreciation on year end plant balances	SC-0800	18	24
Annualize property taxes on year end plant balances	SC-0900		
Adjust for new depreciation rates	SC-1000		
Adjust for post test year additions to plant in service	SC-1100	15	(6,867)
Remove NCEMPA Acquisition Adjustment	SC-1200		
Remove expiring amortization credits from test year	SC-1300		
OPEN	SC-1400		
Adjust reserve for end of life nuclear costs	SC-1500		
Adjust coal inventory	SC-1600		
Adjust for previously deferred amounts - Harris COLA, GridSouth,Fukushima/Cybersecurity, 2014 Storms	SC-1700	(1)	7
Amortize deferred environmental costs	SC-1800	588	(2,351)
Amortize deferred cost balance related to SC AMI	SC-1900	(51)	102
Normalize for storm costs	SC-2000		
Annualize O&M non-labor expenses	SC-2100		
Normalize O&M labor expenses	SC-2200		
Update benefits costs	SC-2300	320	-
Levelize nuclear refueling outage costs	SC-2400		
Amortize rate case costs	SC-2500	-	-
Adjust aviation expenses	SC-2600		
OPEN	SC-2700		
Adjust for credit card fees	SC-2800		
Adjust O&M for executive compensation	SC-2900		
Adjust for Customer Connect additional expense and deferral	SC-3000	9	(18)
Adjust vegetation management expenses	SC-3100	(232)	-
Synchronize interest expense with end of period rate base	SC-3200	(43)	-
Adjust 1/8 O&M for accounting and pro-forma adjustments	SC-3300	-	86
Adjust for Federal tax rate change	SC-3400		
Adjust deferred cost balance related to SC Grid	SC-3500	48	(48)
Remove certain expenses	SC-3600	19	-
Adjust for Allocation of PUC License Tax Expense	SC-3700	(652)	-
Adjust for ongoing payment obligation	SC-3800	(623)	-
Total Supplemental Changes		(585)	(9,065)

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
UPDATED BATEMAN EXHIBIT 3
FOR THE TEST PERIOD ENDED December 31, 2017
SOUTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

Supplemental

			Federal EDIT - Protected SC Retail	Federal EDIT - Unprotected, PP&E related SC Retail	Federal EDIT - Unprotected, non PP&E related SC Retail	Deferred Revenue, DERP Solar Rebate SC Retail	NC EDIT SC Retail	Total SC Retail
			(A)	(B)	(C)	(D)	(E)	(F)
1	Regulatory liability including gross up as of 12/31/2017	[1]	$ (164,960)	$ (47,758)	$ 5,043	$ -	$ (15,176)	(222,870)
1a	Regulatory liability including gross up updated as of 12/31/2018	[1](a)	$ (152,438)	$ (58,254)	$ 867		(5,382)	(215,207)
2	Estimated transition of Protected to Unprotected Regulatory liability during 2018	[1]	$ 5,540		$ (5,540)			-
3	Deferred Revenue for Federal Tax Rate Change as of 12/31/2018	[2]				$ (14,960)		(14,960)
4	DERP Deferral Balance for Solar Rebate as of 9/30/2018	[1]				$ 12,668		12,668
5	Other changes in Regulatory Tax liability	[3]					$ 4,242	4,242
6	Regulatory liability for federal tax change including gross up for Year 1 rider calculation (Sum of L1a to L5)		$ (148,798)	$ (58,254)	$ (4,773)	$ (2,292)	$ (1,140)	(213,257)
7	Annual Amortization percentage		3.70%	5.00%	20.00%	20.00%	100.00%	4.89%
8	Annual amortization amount (L6 x L7)		(5,432)	(2,913)	(955)	(458)	(1,140)	(10,897)
9	Years of rider amortization		27.03	20	5	5	1	

[1] Excess deferred tax liability (EDIT) as of 12/31/2017 by jurisdiction
NC EDIT liability in the 0254037 and 0253600 accounts as of 12/31/2017 forecast as of June 2019.
DERP Solar Rebates are deferred to the 0182494 account
[1](a) Federal EDIT balances updated based on actual balances as of 12/31/2018, and forecast 2018 transition between categories based on Tax analysis of this updated ADIT
[2] Bateman Exhibit 3, Page 3, Line 3. Deferred revenues in the 0229010 account as of 12/31/2018.
[3] Bateman Exhibit 3, Page 4, Line 11, Updated for regulatory liability as of 12/31/2018

ELECTRONICALLY FILED - 2019 January 22 9:30 AM - SCPSC - Docket # 2018-318-E - Page 10 of 18

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
UPDATED BATEMAN EXHIBIT 3
FOR THE TEST PERIOD ENDED December 31, 2017
SOUTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

Supplemental

Cost of Capital per Bateman Exhibit 1	Ratio	Rate	After Tax Weighted Average Cost of Capital (WACC)
Debt	47.00%	4.06%	1.43%
Equity	53.00%	10.50%	5.57%
			7.00%
Statutory Tax Rate SC-0104 - 2017 Tax Rate, Line 10			24.95%
Retention factor for SC license tax, PSC Utility Assessment Fee			99.58%

Annual Rider Calculation

Amortization - From Page 1, L9

Year	Line	Beginning Balance, Page 1, L7	Federal EDIT - Protected	Federal EDIT - Unprotected, PP&E related	Federal EDIT - Unprotected, non PP&E related	Deferred Revenue, DERP Solar Rebate	NC EDIT	Total Amortization	Ending Balance before Return	Average of Beginning and Ending Balance	EDIT Balance in Base Rates, Page 1, L1	Change in Regulatory Liability for Rider Return	Return for Rider	Rider Revenues	Rider Revenues Incl. SC license Tax, PSC Utility Assessment Fee
		(A)	(B)	(C)	(D)	(E)	(F)	(G) =(B)+(C)+(D)+ [E]+[F]	(H) = (A) - (G)	(I) = ((A) + (H)) /2	(J)	(K) = (I) - (J)	(L) = (K) x After Tax WACC	(M) = (G) + (L)	(N) = (M) / Retention Factor
Jun 19- May 20	1	(213,257)	(5,432)	(2,913)	(955)	(458)	(1,140)	(10,897)	(202,359)	($207,808)	(222,870)	$15,062	$1,054	(9,843)	(9,887)
Jun 20- May 21	2	(202,359)	(5,432)	(2,913)	(955)	(458)		(9,757)	(192,602)	($197,481)	(222,870)	$25,389	$1,777	(7,980)	(8,016) [1]
Jun 21- May 22	3	(192,602)	(5,432)	(2,913)	(955)	(458)		(9,757)	(182,845)	($187,724)	(222,870)	$35,146	$2,460	(7,297)	(7,329) [1]
Jun 22- May 23	4	(182,845)	(5,432)	(2,913)	(955)	(458)		(9,757)	(173,088)	($177,966)	(222,870)	$44,903	$3,143	(6,614)	(6,643) [1]
Jun 23- May 24	5	(173,088)	(5,432)	(2,913)	(955)	(458)		(9,757)	(163,330)	($168,209)	(222,870)	$54,661	$3,826	(5,931)	(5,957) [1]

		Rider Revenues Incl. SC license Tax, PSC Utility	Supplemental	Initial Filing	Incr. (decr.) with Update
	6	Jun 19- May 20	(9,887)	(10,008)	122

[1] The rider amounts for years 2 through 5 are shown for illustrative purposes only. Actual rider amounts will be filed each year with updates discussed in my testimony by March 31 for Commission approval.

ELECTRONICALLY FILED - 2019 January 22 9:30 AM - SCPSC - Docket # 2018-318-E - Page 11 of 18

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
UPDATED BATEMAN EXHIBIT 3
FOR THE TEST PERIOD ENDED December 31, 2017
SOUTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation

(Dollars)

	Projected Deferred Revenue for Federal Tax Rate Change in account 0229010	SC Retail
1	Deferrals booked as of 12/31/2018	$ (14,959,840)
2	Forecast deferrals	$ -
3	Deferred Revenue for Federal Tax Rate Change as of 12/31/2018 (L1 + L2)	$ (14,959,840)

ELECTRONICALLY FILED - 2019 January 22 9:30 AM - SCPSC - Docket # 2018-318-E - Page 12 of 18

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
UPDATED BATEMAN EXHIBIT 3
FOR THE TEST PERIOD ENDED December 31, 2017
SOUTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation

Supplemental

(Dollars in thousands)

	NC rate change tax liability (NC EDIT)	Total SC Retail	
1	Annual amortization approved in docket 2016-227-E	$ (12,369)	[1]
2	Tax rate in docket 2016-227-E	38.25%	
3	Current tax rate	24.95%	
4	Annual amortization approved in Docket 2016-227-E adjusted for change in federal tax rate (L1 x (1- L2) / (1- L3))	(10,177)	
5	Additional months of amortization approved in Docket 2018-205-E (Jan 1, 2019 - May 31, 2019) assuming new rates effective June 1, 2019	5	
6	Amortization (Jan 1, 2019- May 31, 2019) (L4/12 x L5)	$ (4,240)	
7	NC deferred tax liability as of 12/31/2018, includes amounts not included in last rate case	$ (5,380)	[2]
8	Amortization from Jan 1, 2019- May 31, 2019 (L5)	$ (4,240)	
9	NC deferred tax liability as of 6/1/2019 (L7 - L8)	$ (1,140)	
10	Regulatory liabilty as of 12/31/2018	$ (5,380)	
11	Change in regulatory tax liability (L9 - L10)	$ 4,240	

[1] Settlement Agreement, Attachment A, Page 4, Line 27 in Docket 2016-227-E.
[2] Per Tax Department as of December 2018

ELECTRONICALLY FILED - 2019 January 22 9:30 AM - SCPSC - Docket # 2018-318-E - Page 13 of 18

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
UPDATED BATEMAN EXHIBIT 3
FOR THE TEST PERIOD ENDED December 31, 2017
SOUTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

			Federal EDIT - Protected SC Retail	Federal EDIT - Unprotected, PP&E related SC Retail	Federal EDIT - Unprotected, non PP&E related SC Retail	Deferred Revenue, DERP Solar Rebate SC Retail	NC EDIT SC Retail	Total SC Retail
			(A)	(B)	(C)	(D)	(E)	(F)
1	Regulatory liability including gross up as of 12/31/2017	[1]	$(154,980)	$ (47,756)	$ 5,043	$ -	$ (15,178)	(222,870)
1a	Regulatory liability including gross up updated as of 12/31/2018	[1](a)	$(152,438)	$ (58,254)	$ 867		(5,382)	(215,207)
2	Estimated transition of Protected to Unprotected Regulatory liability during 2018	[1]	$ 5,640		$ (5,640)			-
3	Deferred Revenue for Federal Tax Rate Change as of 12/31/2018	[2]				$ (14,960)		(14,960)
4	DERP Deferral Balance for Solar Rebate as of 9/30/2018	[1]				$ 12,868		12,868
5	Other changes in Regulatory Tax liability	[3]					$ 4,242	4,242
6	Regulatory liability for federal tax change including gross up for Year 1 rider calculation (Sum of L1a to L5)		$(146,798)	$ (58,254)	$ (4,773)	$ (2,292)	$ (1,140)	(213,257)
7	Annual Amortization percentage		3.70%	5.00%	20.00%	20.00%	100.00%	4.89%
8	Annual amortization amount (L6 x L7)		(5,432)	(2,913)	(955)	(458)	(1,140)	(10,897)
9	Years of rider amortization		27.03	20	5	5	1	

[1] Excess deferred tax liability (EDIT) as of 12/31/2017 by jurisdiction
NC EDIT liability in the 0254037 and 0253600 accounts as of 12/31/2017 forecast as of June 2019.
DERP Solar Rebates are deferred to the 0182494 account
[1](a) Federal EDIT balances updated based on actual balances as of 12/31/2018, and forecast 2018 transition between categories based on Tax analysis of this updated ADIT
[2] Bateman Exhibit 3, Page 3, Line 3. Deferred revenues in the 0229010 account as of 12/31/2018.
[3] Bateman Exhibit 3, Page 4, Line 11. Updated for regulatory liability as of 12/31/2018

ELECTRONICALLY FILED - 2019 January 22 9:30 AM - SCPSC - Docket # 2018-318-E - Page 14 of 18

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
UPDATED BATEMAN EXHIBIT 3
FOR THE TEST PERIOD ENDED December 31, 2017
SOUTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

Cost of Capital per Bateman Exhibit 1	Ratio	Rate	After Tax Weighted Average Cost of Capital (WACC)
Debt	47.00%	4.06%	1.43%
Equity	53.00%	10.50%	5.57%
			7.00%
Statutory Tax Rate SC-0104 - 2017 Tax Rate, Line 10			24.95%
Retention factor for SC license tax, PSC Utility Assessment Fee			99.58%

Annual Rider Calculation

Amortization - From Page 1, L9

Year	Line	Beginning Balance, Page 1, L7 (A)	Federal EDIT - Protected (B)	Federal EDIT - Unprotected, PP&E related (C)	Federal EDIT - Unprotected, non PP&E related (D)	Deferred Revenue, DERP Solar Rebate (E)	NC EDIT (F)	Total Amortization (G) =(B)+(C)+(D)+[E]+[F]	Ending Balance before Return (H) = (A) - (G)	Average of Beginning and Ending Balance (I) = ((A) + (H)) /2	EDIT Balance in Base Rates, Page 1, L1 (J)	Change in Regulatory Liability for Rider Return (K) = (I) - (J)	Return for Rider (L) = (K) x After Tax WACC	Rider Revenues (M) = (G) + (L)	Rider Revenues Incl. SC license Tax, PSC Utility Assessment Fee (N) = (M) / Retention Factor
Jun 19- May 20	1	(213,257)	(5,432)	(2,913)	(955)	(458)	(1,140)	(10,897)	(202,359)	($207,808)	(222,870)	$15,062	$1,054	(9,843)	(9,887)
Jun 20- May 21	2	(202,359)	(5,432)	(2,913)	(955)	(458)		(9,757)	(192,602)	($197,481)	(222,870)	$25,389	$1,777	(7,980)	(8,018) [1]
Jun 21- May 22	3	(192,602)	(5,432)	(2,913)	(955)	(458)		(9,757)	(182,845)	($187,724)	(222,870)	$35,146	$2,460	(7,297)	(7,329) [1]
Jun 22- May 23	4	(182,845)	(5,432)	(2,913)	(955)	(458)		(9,757)	(173,088)	($177,966)	(222,870)	$44,903	$3,143	(6,614)	(6,643) [1]
Jun 23- May 24	5	(173,088)	(5,432)	(2,913)	(955)	(458)		(9,757)	(163,330)	($168,209)	(222,870)	$54,661	$3,826	(5,931)	(5,957) [1]

	Rider Revenues Incl. SC license Tax, PSC Utility	Supplemental	Initial Filing:	Incr. (decr.) with Update
6 Jun 19- May 20		(9,887)	(10,008)	122

[1] The rider amounts for years 2 through 5 are shown for illustrative purposes only. Actual rider amounts will be filed each year with updates discussed in my testimony by March 31 for Commission approval.

ELECTRONICALLY FILED - 2019-January-22 9:30 AM - SCPSC - Docket # 2018-318-E - Page 15 of 18

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
UPDATED BATEMAN EXHIBIT 3
FOR THE TEST PERIOD ENDED December 31, 2017
SOUTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation

(Dollars)

	Projected Deferred Revenue for Federal Tax Rate Change in account 0229010	SC Retail
1	Deferrals booked as of 12/31/2018	$ (14,959,840)
2	Forecast deferrals	$ -
3	Deferred Revenue for Federal Tax Rate Change as of 12/31/2018 (L1 + L2)	$ (14,959,840)

ELECTRONICALLY FILED - 2019 January 22 9:30 AM - SCPSC - Docket # 2018-318-E - Page 16 of 18

DUKE ENERGY PROGRESS, LLC
DOCKET 2018-318-E
UPDATED BATEMAN EXHIBIT 3
FOR THE TEST PERIOD ENDED December 31, 2017
SOUTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation

Supplemental

(Dollars in thousands)

	NC rate change tax liability (NC EDIT)		Total SC Retail	
1	Annual amortization approved in docket 2016-227-E	$	(12,369)	[1]
2	Tax rate in docket 2016-227-E		38.25%	
3	Current tax rate		24.95%	
4	Annual amortization approved in Docket 2016-227-E adjusted for change in federal tax rate (L1 x (1- L2) / (1- L3))		(10,177)	
5	Additional months of amortization approved in Docket 2018-205-E (Jan 1, 2019 - May 31, 2019) assuming new rates effective June 1, 2019		5	
6	Amortization (Jan 1, 2019- May 31, 2019) (L4/12 x L5)	$	(4,240)	
7	NC deferred tax liability as of 12/31/2018, includes amounts not included in last rate case	$	(5,380)	[2]
8	Amortization from Jan 1, 2019- May 31, 2019 (L5)	$	(4,240)	
9	NC deferred tax liability as of 6/1/2019 (L7 - L8)	$	(1,140)	
10	Regulatory liabilty as of 12/31/2018	$	(5,380)	
11	Change in regulatory tax liability (L9 - L10)	$	4,240	

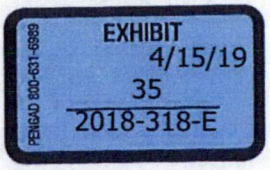
[1] Settlement Agreement, Attachment A, Page 4, Line 27 in Docket 2016-227-E.
[2] Per Tax Department as of December 2018

ELECTRONICALLY FILED - 2019 January 22 9:30 AM - SCPSC - Docket # 2018-318-E - Page 17 of 18

ELECTRONICALLY FILED - 2019 March 29 4:23 PM - SCPSC - Docket # 2018-318-E - Page 1 of 4

BEFORE THE
PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2018-318-E



IN THE MATTER OF:	)	
	)	
Application of Duke Energy Progress, LLC for Adjustments in Electric Rate Schedules and Tariffs	)	**STIPULATION**
	)	
	)	
	)	

This Stipulation is made by and between Duke Energy Progress, LLC (the "Company" or "DEP") and Nucor Steel-South Carolina, a Division of Nucor Corporation ("Nucor") (collectively, the "Parties").

WHEREAS, on November 8, 2018, the Company filed an application in the above-referenced proceeding proposing changes in its rates, charges, and tariffs for electric service to be effective on June 1, 2019 ("Application");

WHEREAS, Nucor, a party to this proceeding, filed direct testimony on March 4, 2019 addressing several issues related to the Application;

WHEREAS, the Parties have varying legal positions regarding the issues in this proceeding;

WHEREAS, the Parties have engaged in discussions to determine whether a settlement of any of the issues would be in their best interests; and

WHEREAS, the Parties have determined that their interests and the public interest would be best served by agreeing to resolve, pursuant to this Stipulation, certain issues in this proceeding that have been raised by Nucor.

NOW, THEREFORE, the Parties agree to the terms and conditions set forth below:

1. The Company agrees to and shall modify its proposed Excess Deferred Income Tax

("EDIT") Rider as follows: (a) all deferred revenues from January 2018 through May 2019, related to the reduction in the federal tax rate, shall be returned to ratepayers over three years (instead of five years as originally proposed in the Application); and (b) the amount of Distributed Energy Resource Program ("DERP") deferred balances to be offset under the Rider shall be reduced to $6 million (instead of $12.66 million as originally proposed in the Application). As a result of these modifications, this approach will return excess deferred tax-related dollars to ratepayers more quickly and there will be a larger credit to ratepayers under the EDIT Rider in the first three years of the rate increase compared to the EDIT Rider as proposed in the Application, while also offsetting almost half of the DERP deferred balances. This proposal is a reasonable compromise on this issue and is unique to the Company due to DEP having had base rate increases in recent years.

2. In determining the LGS-CUR-TOU rate schedule increase in this proceeding, the Company agrees to apply the final approved LGS class percentage revenue increase to the revenues for the LGS-CUR-TOU rate schedule. This proposal is reasonable and equitable under the circumstances.

3. As to the other issues specifically identified and addressed by the pre-filed testimony of Nucor witnesses in this proceeding (aside from the issues addressed in paragraphs 1 and 2 above), Nucor will not seek a Commission decision on these issues in this proceeding. Instead, the Parties have agreed to continue to work together in good faith in an effort to resolve these issues where possible for future rate proceedings. Notwithstanding such efforts, Nucor shall not be precluded in a future proceeding from raising and/or addressing, without prejudice, any issue Nucor witnesses raised in their pre-filed testimony in this proceeding.

ELECTRONICALLY FILED - 2019 March 29 4:23 PM - SCPSC - Docket # 2018-318-E - Page 2 of 4

ELECTRONICALLY FILED - 2019 March 29 4:23 PM - SCPSC - Docket # 2018-318-E - Page 3 of 4

4. Within a reasonable time after the filing of this Stipulation and prior to the commencement of the merits hearing in this proceeding, given the agreement between the Parties, Nucor will withdraw its direct testimony and exhibits filed in this proceeding, and the Company will withdraw its rebuttal testimony that was filed in response to Nucor's witnesses. The Parties agree that such withdrawn testimony and exhibits shall not be entered into evidence in this proceeding.

5. If there is a broader stipulation or settlement agreement entered into between the Company, the Office of Regulatory Staff, and/or other parties to this proceeding, and the parties to such stipulation or settlement (as well as the Company and Nucor) agree, the terms of this Stipulation may be incorporated into that broader stipulation or settlement agreement.

6. The Parties agree that this Stipulation is reasonable, in the public interest, and is in accordance with law and regulatory policy. By narrowing and eliminating some of the issues in this proceeding, this Stipulation also promotes administrative efficiency in the resolution of the issues in this proceeding.

7. This Stipulation does not establish any precedent with respect to the issues resolved herein and in no way precludes either Party from advocating an alternative position in any future proceeding.

8. The Parties agree to cooperate in good faith with one another in recommending to the Commission that this Stipulation be accepted and approved by the Commission as a fair, reasonable, and full resolution of the issues identified in paragraphs 1 and 2 above in this case.

9. Each Party acknowledges its consent and agreement to this Stipulation by authorizing its counsel to affix his or her signature to this document as indicated below. Counsel's

ELECTRONICALLY FILED - 2019 March 29 4:23 PM - SCPSC - Docket # 2018-318-E - Page 4 of 4

signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind the Parties. This document may be signed in counterparts, with the signature pages combined with the body of the document constituting an original and provable copy of this Stipulation.

EXECUTED ON THIS 29th DAY OF MARCH, 2019.

AGREED TO BY:

Duke Energy Progress, LLC

Heather Shirley Smith

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

AGREED TO BY:

Nucor Steel – South Carolina, a Division of Nucor Corporation

Michael Lavanga

By its Counsel:
Michael K. Lavanga
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson Street, NW
Eighth Floor, West Tower
Washington, DC 20007

THE STATE OF SOUTH CAROLINA
BEFORE THE DEPARTMENT OF HEALTH AND ENVIRONMENTAL CONTROL

IN RE: DUKE ENERGY PROGRESS, INC.
H.B. ROBINSON STEAM ELECTRIC PLANT
DARLINGTON COUNTY

CONSENT AGREEMENT
15 – 23 – HW

This Consent Agreement is entered into between the South Carolina Department of Health and Environmental Control (SCDHEC or the Department) and Duke Energy Progress, Inc. (Duke Energy) with respect to the investigation and remediation of the inactive 1960 ash storage area at the H.B. Robinson Steam Electric Plant located at 3581 W. Entrance Road, Hartsville, South Carolina (Tax Map Number 018-00-02-001). The "Site" shall include the inactive 1960 ash storage area and all areas where ash, other coal combustion residuals, or their constituents, including contaminants, (collectively Coal Combustion Residuals or CCR or ash) may have potentially migrated from the 1960 ash storage area, collectively referred to as the "Site" as depicted on Exhibit A.

Duke Energy is entering into this Consent Agreement to assess and address any release or threat of release of Coal Combustion Residuals or other pollutants from the Site to the environment and to provide for the final disposition of the Site. Duke Energy will take all necessary steps in compliance with all environmental laws to prevent future releases from the Site. In the interest of resolving the matters herein without delay, Duke Energy agrees to the entry of this Consent Agreement without litigation and without the admission or adjudication of any issue of fact or law, except for purposes of enforcing this agreement. Duke Energy agrees that this Consent Agreement shall be deemed an admission of fact and law only as necessary for enforcement of this Consent Agreement by the Department or in subsequent actions relating to this Site by the Department.

FINDINGS OF FACT

Based on information known by the Department, the following findings of fact are asserted by the Department for purposes of this Consent Agreement:

1. Duke Energy Progress, Inc. owns and operates both:

   a. The H.B. Robinson Steam Electric Plant (Robinson Plant) located approximately 4.5 miles north of Hartsville, Darlington County, South Carolina. Development of the Robinson Plant facility began in the late 1950s when Black Creek was impounded to create Lake Robinson. Shortly thereafter, the 177 MW coal-fired unit (Unit 1) began commercial operation in 1960. That unit was retired in October 2012. A 710 MW nuclear unit began operation at the site in 1971 and continues to operate. The Tax Map Identification is 018-00-02-001.

   b. The Darlington Plant is located adjacent to the Robinson Plant in Darlington County, South Carolina. The Darlington Plant consists of 13 combustion turbine units and began operation in 1974. Coal has never been used as a fuel at the Darlington Plant. The Tax Map Identification is also 018-00-02-001.

2. The Robinson Plant coal ash management facilities include one ash basin (State Identification Number D3514) located northwest of the fossil and nuclear units; and a 1960 ash storage area located south of the permitted ash basin. The 1960 ash storage area was created in 1960, and received ash from Unit 1 until the permitted ash basin was constructed in the mid-1970s. The 1960 ash storage area covers a surficial area measuring approximately 25 acres with an estimated ash thickness ranging from 6 to 16 feet.

3. Preliminary Site assessment indicates that the preferred disposition of the CCR from the Site is in a South Carolina permitted Class 3 solid waste disposal facility located on the Darlington Plant site and/or the Robinson Site. However, if detailed closure planning

determines that beneficial reuse or disposal in an off-site waste disposal facility is a superior option, then Duke Energy may choose to pursue such options with the consent of the Department.

4. CCR located at the Site lies in an electric transmission corridor, and removal of the ash will require relocation of the transmission line, including its supporting structures. In order to relocate the transmission towers and structures in clean soil, the CCR must be removed in phases, with the first phase consisting of excavation, removal, and disposal of CCR in the area to which the transmission line will be relocated (the Sub-Site). The first phase will require confirmatory sampling to assure the CCR has been removed before erecting the transmission towers and supporting structures in this area. Any groundwater remediation needed for the Sub-Site shall be completed once CCR has been removed from the entire 1960 ash storage area.

CONCLUSIONS OF LAW

The Department has the authority to implement and enforce laws and related regulations pursuant to the South Carolina Hazardous Waste Management Act, S.C. Code Ann. §44-56-10, et seq. (Rev. 2002 and Supp. 2014), the Pollution Control Act, S.C. Code Ann. §48-1-10 et seq. (Rev. 2008 and Supp. 2014) and the South Carolina Solid Waste Policy and Management Act, S.C. Code Ann. §44-96-10, et seq. (Rev. 2002 and Supp. 2014). These Acts authorize the Department to issue orders; assess civil penalties; conduct studies, investigations, and research to abate, control and prevent pollution; and to protect the health of persons or the environment.

NOW, THEREFORE IT IS AGREED, with the consent of Duke Energy and the Department, and pursuant to the South Carolina Hazardous Waste Management Act, the Pollution Control Act, and/or the Solid Waste Policy and Management Act, that Duke Energy shall:

1. Submit an application to construct the Class 3 solid waste disposal facility to the Department no later than April 1, 2016. If a Class 3 solid waste disposal facility cannot be permitted at the Darlington Electric Power Plant and/or the Robinson Plant within five (5) years of the effective date of this agreement, Duke Energy shall dispose of the CCR by another Department approved method.

2. Dispose of all CCR at the Site within a South Carolina permitted Class 3 solid waste disposal facility located at the Darlington Electric Power Plant and/or the Robinson Plant, and complete disposal within eight (8) years following the execution of this Consent Agreement.

3. Within ninety (90) days of receipt of a final and non-appealable permit to construct a Class 3 solid waste disposal facility, commence construction of said solid waste disposal facility and submit to the Department for review and approval, an Ash Removal Plan for the Site. The Ash Removal Plan shall include a time schedule for implementation of all major activities required by the Plan. The Ash Removal Plan must include, but is not limited to, characterization of the ash, provisions for the safe removal of the ash, and management of storm water during the project. The Ash Removal Plan shall also include an evaluation of any stability issues expected to be encountered during ash removal activities. The Ash Removal Plan shall address the impacts to the existing transmission lines and municipal sewer lines and the plans to relocate these utilities as part of the project. Any comments generated through the Department's review of the Ash Removal Plan must be addressed in writing by Duke Energy within fifteen (15) days of Duke Energy's receipt of said comments. Upon the Department's approval of the Ash Removal Plan and the time schedule for implementation thereof, the Ash Removal Plan and schedule shall be incorporated herein and become an enforceable part of this Consent Agreement. The implementation schedule must include the calendar date when all ash will be removed from the Site, not to exceed eight (8) years as outlined in item 2. above.

4. Submit, along with but under separate cover from the Ash Removal Plan, a Health and Safety Plan (HASP) consistent with Occupational Safety and Health Administration regulations. The HASP shall be submitted to the Department in the form of one (1) electronic copy (pdf. format). Duke Energy agrees the HASP is submitted to the Department for informational purposes only. The Department expressly denies any liability that may result from Duke Energy's implementation of the HASP. Begin implementation of the Ash Removal Plan described in paragraph 3. within fifteen (15) days of Duke Energy's receipt of the Department's written approval of the Ash Removal Plan and all required permits, whichever is later, provided Duke Energy submits timely applications for any necessary permits.

5. Upon completion of the work approved at the Site or Sub-Site in accordance with the Ash Removal Plan, submit an Ash Removal Report to the Department. The Ash Removal Report shall summarize the activities taken during implementation of the Ash Removal Plan and shall contain appropriate documentation that ash has been removed from the Site or Sub-Site and properly disposed of in accordance with the Ash Removal Plan.

6. Within thirty (30) days of approval of the Ash Removal Report(s), submit an Assessment Plan to the Department. The Assessment Plan shall include, but is not limited to, the following: a description of work needed for the delineation of the vertical and horizontal extent of any contamination, including an assessment of surface water, groundwater, and soil underlying the Site; a conceptual site model to ensure assessment of all potential risks to human health and the environment; and a schedule for implementation.

7. Upon completion of the activities outlined in the approved Assessment Plan, within sixty (60) days submit to the Department an Assessment Report summarizing the findings of the investigations performed pursuant to the Assessment Plan, including an evaluation of all risks to human health and the environment. The Department shall review the Assessment Report to determine completion of the field investigation and sufficiency of

the documentation. If the Department determines that additional field investigation is necessary, Duke Energy shall conduct additional field investigation to complete such task. Alternatively, if the Department determines the field investigation to be complete, but the conclusions in Duke Energy's Assessment Report are not approved, Duke Energy shall submit a Revision to the Assessment Report within thirty (30) days after receipt of the Department's disapproval. The Revision shall address the Department's comments.

8. Within sixty (60) days of approval of all Assessment Reports, submit to the Department a Closure Plan which details the actions to be taken for the final disposition of the Site, and evaluates the need for additional remediation of soils, surface water and groundwater. If remedial actions are necessary, Duke Energy shall also submit to the Department for approval a Remedial Plan, which includes a proposed remedy, justification for the proposed remedy, the design of the proposed remedy and a schedule for implementation. The schedule of implementation must extend through full completion of the remedy. The Closure Plan and, if necessary, the Remedial Plan shall be based upon the results of the field investigation, ash removal activities and the following seven (7) criteria:

   a. Overall protection of human health and the environment;

   b. Compliance with applicable or relevant and appropriate standards;

   c. Long-term effectiveness and permanence;

   d. Reduction of toxicity, mobility or volume;

   e. Short-term effectiveness;

   f. Implementability; and

   g. Costs.

9. Address any comments generated through the Department's review of the Closure Plan and any required Remedial Plan in writing within fifteen (15) days of Duke Energy's receipt of said comments. This fifteen (15) day deadline may be extended by mutual agreement of the parties if the comment resolution requires extensive revision, such as

reengineering. Upon Department approval of the Closure Plan, Remedial Plan and the implementation schedule, the Closure Plan, Remedial Plan, and implementation schedule shall be incorporated herein and become an enforceable part of this Consent Agreement.

10. Begin to implement the Closure Plan and the Remedial Plan within forty-five (45) days of the Department's approval of the Plans; and thereafter, take all necessary and reasonable steps to ensure timely completion of the Plans.

11. Submit to the Department a written monthly progress report within thirty (30) days of the execution of this Consent Agreement and by the last business day of every month thereafter until completion of the work required under this Consent Agreement. The progress reports shall include the following: (a) a description of the actions which Duke Energy has taken toward achieving compliance with this Consent Agreement during the previous month; (b) results of sampling and tests, in summary format received by Duke Energy during the reporting period; (c) description of all actions which are scheduled for the next month to achieve compliance with this Consent Agreement, and other information relating to the progress of the work as deemed necessary or requested by the Department; and (d) information regarding the percentage of work completed and any delays encountered or anticipated that may affect the approved schedule for implementation of the terms of this Consent Agreement, and a description of efforts made to mitigate delays or avoid anticipated delays.

12. Prepare all Plans and perform all activities under this Consent Agreement following appropriate DHEC and EPA guidelines. All Plans and associated reports, with the exception of the Monthly Reports required by paragraph 12 and the HASP required by paragraph 4. above, shall be prepared in accordance with industry standards and endorsed by a Professional Engineer (P.E.) and/or Professional Geologist (P.G.) duly-licensed in South Carolina. Unless otherwise requested, one (1) paper copy and one (1) electronic copy (pdf. format) of each document prepared under this Consent Agreement shall be

submitted to the Department's Project Manager. Unless otherwise directed in writing, all correspondence, work plans and reports should be submitted to the Department's Project Manager at the following address:

Tim Hornosky
South Carolina Department of Health and Environmental Control
Bureau of Land and Waste Management
2600 Bull Street
Columbia, South Carolina 29201
hornostr@dhec.sc.gov

13. Reimburse the Department on a quarterly basis, for all past, present and future costs, direct and indirect, incurred by the Department pursuant to this Consent Agreement and as provided by law. Oversight Costs include, but are not limited to, the direct and indirect costs of negotiating the terms of this Consent Agreement, reviewing plans and reports, supervising corresponding work and activities, and costs associated with public participation. The Department shall provide documentation of its Oversight Costs in sufficient detail so as to show the personnel involved, amount of time spent on the project for each person, expenses, and other specific costs. Payments are due to the Department within thirty (30) days of the date of the Department's invoice; however, it is not a violation of this Consent Agreement if late payment is cured within thirty (30) additional days.

14. Meet with the Department's Project Manager at least quarterly to discuss progress toward schedule requirements and to anticipate any schedule delays.

15. Notify the Department in writing at least five (5) days before the scheduled deadline if any event occurs which causes or may cause a delay in meeting any of the above-scheduled dates for completion of any specified activity pursuant to this Consent Agreement. Duke Energy shall describe in detail the anticipated length of the delay, the precise cause or causes of delay, if ascertainable, the measures taken or to be taken to

prevent or minimize the delay, and the timetable by which Duke Energy proposes that those measures will be implemented. The Department shall provide written notice to Duke Energy as soon as practicable that a specific extension of time has been granted or that no extension has been granted. An extension shall be granted for any scheduled activity delayed by an event of *force majeure* which shall mean any event arising from causes beyond the control of Duke Energy that causes a delay in or prevents the performance of any of the conditions under this Consent Agreement including, but not limited to: a) acts of God, fire, war, insurrection, civil disturbance, explosion; b) adverse weather conditions that could not be reasonably anticipated causing unusual delay in transportation and/or field work activities; c) restraint by court order or order of public authority; d) inability to obtain, after exercise of reasonable diligence and timely submittal of all required applications, any necessary authorizations, approvals, permits, or licenses due to action or inaction of any governmental agency or authority, or litigation staying or reversing permit issuance or other governmental agency approvals; and e) delays caused by compliance with applicable statutes or regulations governing contracting, procurement or acquisition procedures, despite the exercise of reasonable diligence by Duke Energy. Events which are not *force majeure* include by example, but are not limited to, unanticipated or increased costs of performance, changed economic circumstances, normal precipitation events, or failure by Duke Energy to exercise due diligence in obtaining governmental permits or performing any other requirement of this Consent Agreement or any procedure necessary to provide performance pursuant to the provisions of this Consent Agreement. Any extension shall be granted at the sole discretion of the Department, incorporated by reference as an enforceable part of this Consent Agreement, and thereafter, be referred to as an attachment to the Consent Agreement.

16. Upon Duke Energy's successful completion of the terms of this Consent Agreement, submit to the Department a written Final Report. The Final Report shall contain all necessary documentation supporting Duke Energy's remediation of the Site and successful and complete compliance with this Consent Agreement. Once the Department has approved the Final Report, the Department will provide Duke Energy a written approval of completion that provides Covenant Not to Sue to Duke Energy for the response actions specifically covered in this Consent Agreement, approved by the Department and completed in accordance with the approved work plans and reports.

17. Notwithstanding any other provision of this Consent Agreement, including the Covenant Not to Sue, the Department reserves the right to require Duke Energy to perform any additional work at the Site or to reimburse the Department for additional work if Duke Energy declines to undertake such work, if: (i) conditions at the Site, previously unknown to the Department, are discovered after completion of the work approved by the Department pursuant to this Consent Agreement and warrant further assessment or remediation to address a release or threat of a release in order to protect human health or the environment, or (ii) information is received, in whole or in part, after completion of the work approved by the Department pursuant to this Consent Agreement, and these previously unknown conditions of this information indicate that the completed work is not protective of human health and the environment. In exigent circumstances, the Department reserves the right to perform the additional work and Duke Energy will reimburse the Department for the work.

18. In consideration for the Department's Covenant Not to Sue, Duke Energy agrees not to assert any claims or causes of action against the Department arising out of response activities undertaken at the Site, or to seek any other costs, damages or attorney's fees from the Department arising out of response activities undertaken at the Site except for those claims or causes of action resulting from the intentional or grossly negligent acts or

omissions of the Department. However, Duke Energy reserves all available defenses, not inconsistent with this Consent Agreement, to any claims or causes of action asserted against Duke Energy arising out of response activities undertaken at the Site by the Department.

19. Employees of the Department, their respective consultants and contractors will not be denied access during normal business hours or at any time work under this Consent Agreement is being performed or during any environmental emergency or imminent threat situation, as determined by the Department or as allowed by applicable law.

IT IS AGREED THAT this Consent Agreement shall be binding upon and inure to the benefit of Duke Energy and its officers, directors, agents, receivers, trustees, heirs, executors, administrators, successors, and assigns and to the benefit of the Department and any successor agency of the State of South Carolina that may have responsibility for and jurisdiction over the subject matter of this Consent Agreement. Duke Energy may not assign it rights or obligations under this Consent Agreement without the prior written consent of the Department.

IT IS FURTHER AGREED that failure to meet any deadline or to perform the requirements of this Consent Agreement without an approved extension of time and failure to timely cure as noted below, may be deemed a violation of the Pollution Control Act, the South Carolina Hazardous Waste Management Act and/or the Solid Waste Management and Policy Act, as amended. Upon ascertaining any such violation, the Department shall notify Duke Energy in writing of any such deemed violation and that appropriate action may be initiated by the Department in the appropriate forum to obtain compliance with the provisions of this Consent Agreement and the aforesaid Acts. Duke Energy shall have thirty (30) days to cure any deemed violations of this Consent Agreement. Applicable penalties may begin to accrue after issuance of the Department's determination that the alleged violation has not been cured during that thirty (30) day period.

(Signature Page Follows)

FOR THE SOUTH CAROLINA DEPARTMENT
OF HEALTH AND ENVIRONMENTAL CONTROL

for Elizabeth A. Dieck
Director of Environmental Affairs
Date: 7/17/2015

Daphne G. Neel, Chief
Bureau of Land and Waste Management
Date: 7/16/15

Van Keisler, P.G., Director
Division of Compliance and Enforcement
Date: 7-16-15

Reviewed By:

Attorney
Office of General Counsel
Date: 7/16/15

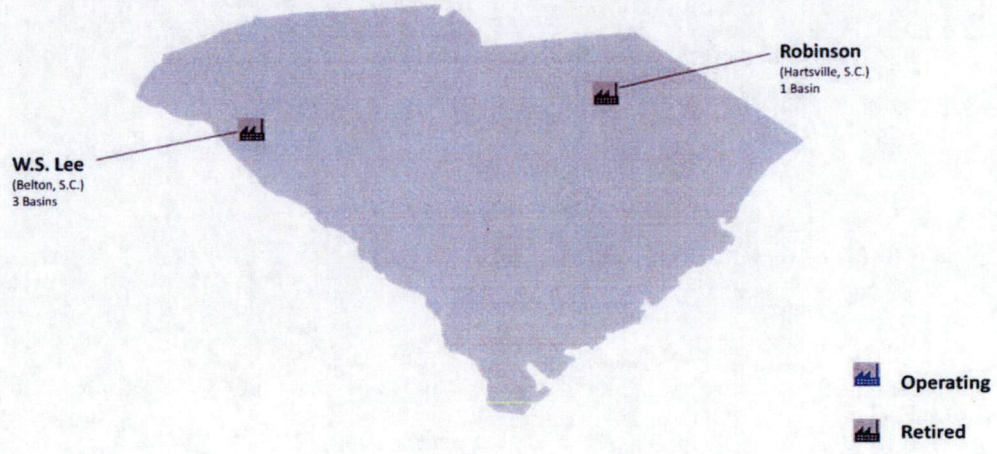
WE CONSENT:

DUKE ENERGY PROGRESS, INC.

(Signature)
Date: July 15, 2015

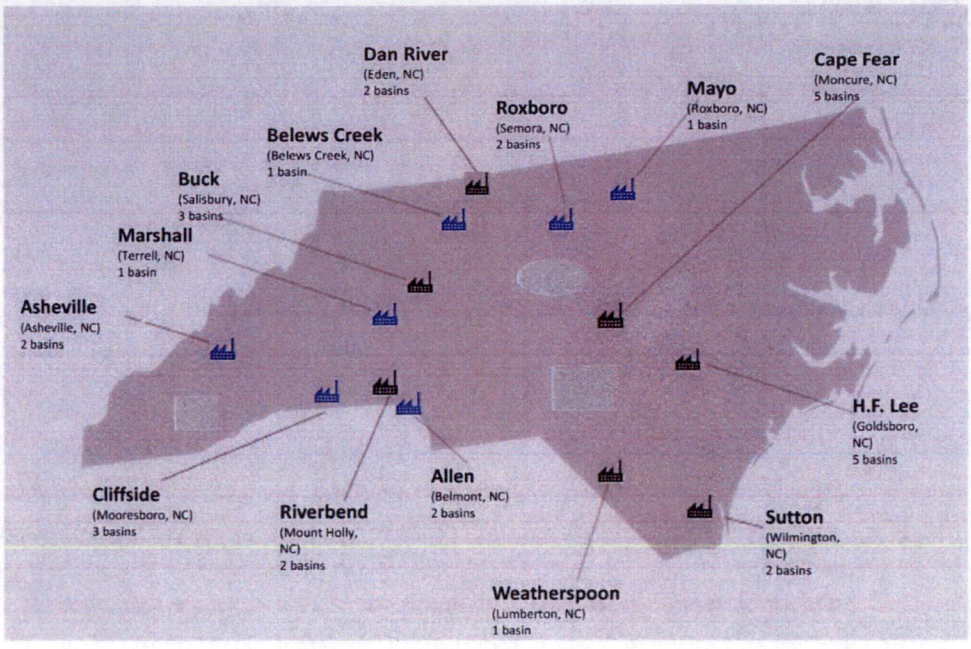
John Elnitsky, Senior V.P.
Please clearly print name and title

Duke Energy South Carolina Sites and Number of Ash Basins



ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 1 of 24

Duke Energy North Carolina Sites and Number of Ash Basins



ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 2 of 24

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 3 of 24

Site Facts - DEP

Site	Commercial Operation Date	Generation Capacity (MW)	Retirement Date, if applicable	Possible closure approach	Quantity of ash on site in basins 7/31/18 (million tons)	Is a CCR landfill envisioned for the site?
Asheville	1964	376	n/a	Offsite excavation	2.1MT	No
Cape Fear	1923	316	2012	Beneficiation	5.7MT	Yes
HF Lee	1951	382	2012	Beneficiation	6.2MT	No
Mayo	1983	727	n/a	Cap in Place	6.6MT	No
Robinson	1960	177	2012	Onsite landfill	2.9MT	Yes
Roxboro	1966	2439	n/a	Cap in place	20.1MT	No
Sutton	1954	553	2013	Offsite excavation/onsite landfill	2.6MT	Yes
Weatherspoon	1949	170	2011	Offsite excavation/beneficiation	2.2MT	No

DEP

Ash Basin Information

Site	Basin	When constructed	Ash in Tons as of 7/31/18 (Millions)	When closed if applicable	CCR Applicable?
Asheville	1964 Basin	1964	2.1	n/a	Y
	1982 Basin	1982	0	n/a	Y
Cape Fear	1956 Basin	1956	0.4	1963	N
	1963 Basin	1963	0.9	1978	N
	1970 Basin	1970	0.8	1978	N
	1978 Basin	1978	0.8	1985	N
	1985 Basin	1985	2.8	2012	N
HF Lee	1950 Basin	1950	0.3	1969	N
	1955 Basin	1955	0.5	1969	N
	1962 Basin	1962	0.9	1973	N
	1982 Basin	1978	4.5	2012	Y
	Polishing Pond	1982	0.009	2012	N
Mayo	Ash basin	1983	6.6	n/a	Y
Robinson	Ash Basin	Mid 1970s	2.9	10/1/2012	Y
Roxboro	East Ash Basin	1963	7.1	1983	Y
	West Ash Basin	1973	13	n/a	Y
Sutton	1971 Basin	1971	1.5	**U1 & U2** 11/27/13 **U3** 11/4/13	Y
	1984 Basin	1984	1.1	**U1 & U2** 11/27/13 **U3** 11/4/14	Y
Weatherspoon	Ash Basin	1955	2.2	9/30/2011	Y

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 4 of 24

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 5 of 24

Duke Energy Progress
Responses to Rule Changes Through the Decades

	1920s	1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s
Industry Standard	Fly ash discharged through smoke stacks. Bottom ash placed in landfills.	Fly ash discharged through smoke stacks. Bottom ash placed in landfills.	Fly ash discharged through smoke stacks. Bottom ash placed in landfills.	Fly ash discharged through smoke stacks. Water sluicing to ash basins for bottom ash.	Fly ash discharged through smoke stacks. Water sluicing to ash basins for bottom ash.	Fly ash discharged through smoke stacks. Water sluicing to ash basins for bottom ash.	Fly ash contained by ESPs. Water sluicing to ash basins for fly and bottom ash.	Fly ash contained by ESPs. Water sluicing to ash basins for fly and bottom ash. Water sluicing to ash basins for FGD byproducts	Fly ash contained by ESPs. Water sluicing to ash basins for fly and bottom ash. Water sluicing to ash basins for FGD
DEP Coal Plants	Cape Fear	Cape Fear	Cape Fear Weatherspoon	Cape Fear Weatherspoon HF Lee Sutton	Cape Fear Weatherspoon HF Lee Sutton Robinson Asheville Roxboro	Cape Fear Weatherspoon HF Lee Sutton Robinson Asheville Roxboro	Cape Fear Weatherspoon HF Lee Sutton Robinson Asheville Roxboro Mayo	Cape Fear Weatherspoon HF Lee Sutton Robinson Asheville Roxboro Mayo	Asheville Roxboro Mayo
DEP Ash Basins	None	None	None	Cape Fear HF Lee Weatherspoon	Cape Fear HF Lee Weatherspoon Asheville Roxboro	Cape Fear HF Lee Weatherspoon Asheville Roxboro Sutton Robinson	Cape Fear HF Lee Weatherspoon Asheville Roxboro Sutton Robinson Mayo	Cape Fear HF Lee Weatherspoon Asheville Roxboro Sutton Robinson Mayo	Cape Fear HF Lee Weatherspoon Asheville Roxboro Sutton Robinson Mayo
Law Changes	None	None	None	None	None	Clean Air Act Clean Water Act	Clean Air Act	None	CCR/CAMA
Industry Standard Changes	None	None	Water sluicing to ash basins	None	None	ESPs deployed on coal plants. NPDES/ELG permits and guidelines	FGD/Scrubbers to control sulfur emissions	None	Dry CCR handling or plant closure. Excavation and removal or cap in place for basins.
Plant and/or Basin Modifications	None	None	Water sluicing deployed to coal plants. Ash basins begin to be built	None	None	ESP's added to plants. Basin use conformed to NPDES/ELG permits and guidelines.	FGD/Scrubbers to some plants	FGD/Scrubbers to some plants	Dry CCR handling or plant closure. Excavation and removal or cap in place for basins.

Kerin Exhibit 7
Docket No. 2018-318-E

Duke Energy Corporation
Summary of Ash Beneficiation for Duke Energy Progress
2015 , 2016, 2017 and 2018 January to August

2015	DEP
Ash Produced	602,576
Production Ash Reused	170,267
Ash Sluiced	171,663
Ash Landfilled	579,896
Ash to Structural Fill	-
Reclaimed Ash for Beneficial Reuse	-
2016	**DEP**
Ash Produced	491,252
Production Ash Reused	99,686
Ash Sluiced	230,295
Ash Landfilled	434,198
Ash to Structural Fill	640
Reclaimed Ash for Beneficial Reuse	-
2017	**DEP**
Ash Produced	349,679
Production Ash Reused	81,993
Ash Sluiced	150,024
Ash Landfilled	742,407
Ash to Structural Fill	21
Reclaimed Ash for Beneficial Reuse	-
2018	**DEP**
Ash Produced	253,874
Production Ash Reused	149,754
Ash Sluiced	105,544
Ash Landfilled	716,408
Ash to Structural Fill	44,374
Reclaimed Ash for Beneficial Reuse	354,117

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 6 of 24

DEC - 2018	January	February	March	April	May	June	July	August	September	October	November	December	YTD
ALLEN STATION													
DRY FLY ASH PRODUCED	13,160.32	284.45	0.00	217.82	2,844.53	4,286.40	882.86	1,576.49	0.00	0.00	0.00	0.00	23,252.85
DRY BOTTOM ASH PRODUCED	1,668.21	36.06	0.00	27.61	360.57	543.35	111.91	199.84	0.00	0.00	0.00	0.00	2,947.54
TOTAL ASH PRODUCED	14,828.52	320.50	0.00	245.43	3,205.11	4,829.74	994.77	1,776.32	0.00	0.00	0.00	0.00	26,200.40
ASH SLUICED TO POND	1,668.21	36.06	0.00	27.61	360.57	543.35	111.91	199.84	0.00	0.00	0.00	0.00	2,947.54
ASH LANDFILLED *	21,499.93	904.99	0.00	0.00	4,439.61	4,330.03	1,533.75	957.72	0.00	0.00	0.00	0.00	33,666.03
CENOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	16.40	0.00	0.00	0.00	0.00	0.00	13.80	0.00	0.00	0.00	0.00	0.00	30.20
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED TO STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BELEWS CREEK STATION													
DRY FLY ASH PRODUCED	40,175.40	7,400.16	22,950.20	650.82	29,213.17	31,544.11	25,169.87	29,808.45	0.00	0.00	0.00	0.00	186,912.18
DRY BOTTOM ASH PRODUCED	5,092.66	938.05	2,909.18	82.50	3,703.08	3,998.55	3,190.55	3,778.54	0.00	0.00	0.00	0.00	23,693.09
TOTAL ASH PRODUCED	45,268.06	8,338.21	25,859.38	733.32	32,916.25	35,542.66	28,360.42	33,586.98	0.00	0.00	0.00	0.00	210,605.28
ASH SLUICED TO POND	5,092.66	938.05	2,909.18	82.50	3,703.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12,725.46
ASH LANDFILLED *	18,502.55	431.13	0.00	25.17	7,668.00	14,859.13	4,959.46	6,903.05	0.00	0.00	0.00	0.00	53,348.49
CENOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	14,926.42	23,536.85	12,241.06	13,549.26	17,166.51	23,845.10	24,553.02	27,463.05	0.00	0.00	0.00	0.00	157,281.27
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CLIFFSIDE STATION													
DRY FLY ASH PRODUCED	19,051.17	8,431.92	12,215.79	10,049.01	8,835.50	15,684.93	15,804.46	12,159.81	0.00	0.00	0.00	0.00	102,232.59
DRY BOTTOM ASH PRODUCED	2,414.94	1,068.83	1,548.48	1,273.82	1,119.99	1,988.23	2,003.38	1,541.38	0.00	0.00	0.00	0.00	12,959.06
TOTAL ASH PRODUCED	21,466.11	9,500.75	13,764.27	11,322.83	9,955.50	17,673.16	17,807.84	13,701.19	0.00	0.00	0.00	0.00	115,191.65
ASH SLUICED TO POND	900.95	267.64	284.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,453.10
ASH LANDFILLED *	33,192.08	22,715.77	21,350.74	22,743.95	20,581.36	30,865.75	32,403.35	25,969.41	0.00	0.00	0.00	0.00	209,822.41
CENOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STRUCTURAL FILL ASH	2,927.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2,927.28
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MARSHALL STATION													
DRY FLY ASH PRODUCED	28,998.83	10,156.10	17,301.55	22,519.73	22,144.80	26,480.77	22,008.85	21,890.06	0.00	0.00	0.00	0.00	171,500.70
DRY BOTTOM ASH PRODUCED	3,675.91	1,287.39	2,193.15	2,854.61	2,807.09	3,356.72	2,789.85	2,774.80	0.00	0.00	0.00	0.00	21,739.52
TOTAL ASH PRODUCED	32,674.74	11,443.49	19,494.71	25,374.34	24,951.89	29,837.49	24,798.71	24,664.86	0.00	0.00	0.00	0.00	193,240.22
ASH SLUICED TO POND	3,675.91	1,287.39	2,193.15	2,854.61	2,807.09	3,356.72	2,789.85	2,774.80	0.00	0.00	0.00	0.00	21,739.52
ASH LANDFILLED *	46,024.39	14,083.86	26,029.68	28,176.24	30,376.85	37,289.93	33,020.90	38,846.08	0.00	0.00	0.00	0.00	253,847.93
Fly Ash Sales					3,337.12	848.24	0.00	999.93	0.00	0.00	0.00	0.00	5,185.29
ASH BENEFICIAL REUSE	2,633.14	3,762.78	5,244.29	8,206.50	5,291.77	3,530.91	1,915.20	1,383.20	0.00	0.00	0.00	0.00	31,967.79
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ash Produced	**545,238**				**percent reuse**		**36%**						

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 7 of 24

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 8 of 24

Production Ash Reused	194,465
Ash Sluiced	38,866
Ash Landfilled	550,685
Ash to Structural Fill	2,927
Reclaimed Ash for Beneficial Reuse	0

DEP - 2018													
ASHEVILLE STATION													
DRY FLY ASH PRODUCED	6,023.16	3,286.44	3,786.77	4,309.87	1,873.43	3,733.89	2,562.80	3,121.23	0.00	0.00	0.00	0.00	28,697.59
DRY BOTTOM ASH PRODUCED	763.50	416.59	480.01	546.32	237.48	473.31	324.86	395.65	0.00	0.00	0.00	0.00	3,637.72
TOTAL ASH PRODUCED	6,786.66	3,703.03	4,266.78	4,856.20	2,110.90	4,207.20	2,887.66	3,516.88	0.00	0.00	0.00	0.00	32,335.31
ASH SLUICED TO POND	6,786.66	3,703.03	4,266.78	4,856.20	2,110.90	4,207.20	2,887.66	3,516.88	0.00	0.00	0.00	0.00	32,335.31
ASH LANDFILLED *	61,572.00	66,951.00	74,475.00	73,943.00	73,114.00	69,176.00	68,529.00	71,109.00	0.00	0.00	0.00	0.00	558,869.00
CENOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED TO STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MAYO STATION													
DRY FLY ASH PRODUCED	11,012.93	2,673.05	3,585.49	7,060.44	5,054.10	7,246.97	5,802.37	5,850.37	0.00	0.00	0.00	0.00	48,285.73
DRY BOTTOM ASH PRODUCED	1,396.01	338.84	454.50	894.99	640.66	918.63	735.51	741.60	0.00	0.00	0.00	0.00	6,120.73
TOTAL ASH PRODUCED	12,408.94	3,011.89	4,039.99	7,955.43	5,694.76	8,165.60	6,537.88	6,591.97	0.00	0.00	0.00	0.00	54,406.45
ASH SLUICED TO POND	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH LANDFILLED *	13,368.25	4,690.68	2,989.12	7,635.11	8,231.33	9,615.10	7,131.25	6,677.87	0.00	0.00	0.00	0.00	60,338.71
CENOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	25.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.22
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH TO STRUCTURAL FILL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROXBORO STATION													
DRY FLY ASH PRODUCED	33,660.35	8,685.34	10,757.48	6,830.21	11,806.80	26,646.24	22,806.21	27,137.66	0.00	0.00	0.00	0.00	148,330.29
DRY BOTTOM ASH PRODUCED	4,266.80	1,100.96	1,363.62	865.80	1,496.64	3,377.69	2,890.93	3,439.98	0.00	0.00	0.00	0.00	18,802.43
TOTAL ASH PRODUCED	37,927.15	9,786.29	12,121.11	7,696.02	13,303.44	30,023.93	25,697.13	30,577.64	0.00	0.00	0.00	0.00	167,132.72
ASH SLUICED TO POND	4,266.80	1,100.96	1,363.62	865.80	1,496.64	3,377.69	2,890.93	3,439.98	0.00	0.00	0.00	0.00	18,802.43
ASH LANDFILLED *	46,123.36	13,824.89	0.00	0.00	39.00	1,993.69	28,910.70	6,308.50	0.00	0.00	0.00	0.00	97,200.14
CENOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	9,474.32	20,580.87	20,325.65	9,797.48	12,372.67	34,343.49	4,148.71	38,685.98	0.00	0.00	0.00	0.00	149,729.17
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH TO STRUCTURAL FILL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 9 of 24

DEP										
Ash Produced		253,874				percent reuse		59%		
Production Ash Reused		149,754								
Ash Sluiced		105,544								
Ash Landfilled		716,408								
Ash to Structural Fill		0								
Reclaimed Ash for Beneficial Reuse		0								
Combined		799,112				percent reuse		43%		
Production Ash Reused		344,219								
DEP & DEC	Total CCP Produced	336,469	103,577	166,874	125,970	193,013	277,643	243,537	250,665	1,697,748
	Total CCP Reused	115,879	119,340	128,544	125,684	144,944	160,449	123,971	163,262	1,082,072
	% Ash Reuse	29%	136%	80%	104%	77%	72%	59%	92%	71%
	% Gypsum Reuse	54%	124%	104%	139%	106%	66%	68%	70%	82%
	% Total CCP Reuse	34%	115%	77%	100%	75%	58%	51%	65%	64%

2018 CCP August Utilization Station Health

* Ash Landfilled represent the moist tons of CCR's weighed and placed in the landfills monthly.

WASTE	REUSE	RECLAIMS	TOTAL GYPSUM TEMPORARY STACK (ones or tons

SHC - 2017	January	February	March	April	May	June	July	August	September	October	November	December	YTD
ALLEN STATION													
DRY FLY ASH PRODUCED	3,757.28	944.33	1,368.37	1,966.70	1,845.18	2,985.60	3,132.36	4,134.05	1,894.39	4,842.82	61.82	1,913.35	36,866.33
DRY BOTTOM ASH PRODUCED	1,491.48	66.31	375.56	492.43	462.25	851.40	2,340.56	1,134.36	1,346.51	1,160.75	15.45	478.08	9,714.54
TOTAL ASH PRODUCED	7,446.98	131.67	1,837.90	2,442.13	2,316.46	3,756.99	11,502.86	6,173.36	4,342.75	5,466.54	77.27	2,296.44	46,571.52
ASH SLURCED TO POND	1,486.48	66.33	375.56	492.43	462.25	851.40	2,340.56	1,134.36	1,346.51	1,160.71	15.45	478.08	9,714.56
ASH LANDFILLED *	11,389.26	0.00	0.00	0.00	0.00	1,429.17	11,131.96	6,366.13	5,139.29	7,777.13	448.23	1,343.91	54,357.84
CE NOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.00	56.00	0.00	7.00	0.00	42.00
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED TO STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BELEWS CREEK STATION													
DRY FLY ASH PRODUCED	17,254.27	5,809.64	34,625.14	36,713.95	35,267.86	34,388.66	44,887.95	42,298.87	14,751.82	8,112.78	12,791.37	25,660.51	314,764.36
DRY BOTTOM ASH PRODUCED	2,113.57	962.13	6,452.84	6,475.88	4,361.42	4,771.61	5,771.66	5,376.86	1,611.18	1,887.42	1,586.36	3,174.60	39,156.73
TOTAL ASH PRODUCED	19,367.84	6,362.36	40,462.18	43,189.83	39,629.31	43,160.27	52,660.60	47,675.56	16,362.99	9,949.21	14,377.81	28,834.91	353,913.78
ASH SLURCED TO POND	2,113.57	962.13	6,452.84	6,475.88	4,361.42	4,771.61	5,771.66	5,376.86	1,611.18	1,887.42	1,586.36	3,174.60	39,156.73
ASH LANDFILLED *	3,311.86	0.00	0.00	6,879.75	0.00	2,753.46	6,646.96	10,888.52	1,366.10	1,797.77	1,343.96	134.36	34,967.64
CE NOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	16,541.31	12,144.26	13,256.18	20,148.77	35,286.79	44,877.97	34,172.89	36,394.16	29,987.54	12,568.95	7,707.05	14,588.84	298,680.79
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CLIFFSIDE STATION													
DRY FLY ASH PRODUCED	18,902.13	13,345.73	11,548.71	17,642.57	13,317.34	12,358.88	12,777.36	12,230.61	12,662.36	12,576.17	5,448.16	6,880.96	153,611.17
DRY BOTTOM ASH PRODUCED	2,748.74	1,863.25	1,734.34	2,644.13	2,061.66	1,946.73	2,055.27	1,947.38	1,862.41	1,546.57	815.67	908.66	22,954.44
TOTAL ASH PRODUCED	21,151.86	15,208.98	13,283.05	20,286.70	15,379.00	14,305.60	14,832.62	14,177.99	14,524.77	14,122.74	6,263.83	7,789.62	176,566.61
ASH SLURCED TO POND	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH LANDFILLED *	12,099.27	24,425.13	13,743.71	20,557.95	14,349.47	24,858.71	25,173.06	23,259.94	20,999.15	20,925.84	7,948.93	4,345.72	231,345.74
CE NOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STRUCTURAL FILL ASH	9,056.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MARSHALL STATION													
DRY FLY ASH PRODUCED	24,434.53	17,212.00	19,735.99	15,962.89	16,504.24	15,500.96	21,758.60	27,539.17	10,349.41	22,508.16	22,451.27	22,366.99	267,334.15
DRY BOTTOM ASH PRODUCED	4,863.12	3,254.82	3,442.72	2,817.34	2,868.75	4,429.99	5,369.51	4,138.47	2,414.68	3,972.96	3,852.34	4,137.51	47,215.79
TOTAL ASH PRODUCED	31,866.14	20,376.82	23,218.56	18,781.05	19,534.99	19,138.97	27,128.12	32,096.79	12,764.81	26,465.19	26,351.61	27,514.08	314,771.94
ASH SLURCED TO POND	4,863.12	3,254.82	3,442.72	2,817.34	2,868.75	4,429.99	5,369.51	4,138.47	2,414.68	3,972.96	3,852.34	4,137.51	47,215.79
ASH LANDFILLED *	26,474.43	26,455.39	29,114.76	21,466.17	24,452.26	48,862.61	48,856.72	43,454.36	24,454.49	31,824.27	26,777.35	23,462.75	365,444.54
CE NOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fly Ash Sales	788.68	2,661.72	2,693.83	34.55	49.31	0.00	0.00	0.00	1,010.20	2,747.86	2,224.47	180.86	12,706.16
ASH BENEFICIAL REUSE	4,877.26	7,114.85	4,196.25	797.28	1,611.62	2,059.86	1,887.32	2,196.24	3,572.57	4,527.64	4,211.74	2,990.06	37,752.67
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Ash Produced	897,848			
Production Ash Reused	344,598			
Ash Stored	36,892			
Ash Landfilled	730,772			
Ash to Structural Fill	0			
Reclaimed Ash for Beneficial Reuse	0			

SHP - 2017													
ASHEVILLE STATION													
DRY FLY ASH PRODUCED	3,744.19	3,366.81	4,617.36	2,566.12	2,399.36	3,615.51	4,666.30	3,821.84	1,510.46	2,611.78	1,376.29	4,758.79	41,394.54
DRY BOTTOM ASH PRODUCED	736.64	641.56	1,154.34	641.53	599.83	886.38	1,332.87	988.26	412.62	709.53	494.67	1,884.57	9,751.24
TOTAL ASH PRODUCED	4,476.84	4,007.51	5,771.71	3,207.65	2,999.18	4,501.89	5,999.18	4,810.10	1,923.08	3,321.31	1,870.96	6,643.36	51,795.82
ASH SLURCED TO POND	4,476.84	4,387.51	5,771.71	3,207.65	2,999.18	4,501.89	5,999.18	4,810.10	1,923.08	3,321.31	1,870.96	6,643.36	51,795.82
ASH LANDFILLED *	42,944.28	48,908.88	45,843.80	34,366.89	39,441.88	48,544.98	34,425.00	38,342.00	25,536.88	26,062.00	20,172.00	48,652.00	443,386.00
CE NOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED TO STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WAYNE STATION													
DRY FLY ASH PRODUCED	4,134.80	3,681.76	4,993.54	1,726.87	834.56	4,714.56	8,994.95	7,887.42	873.34	1,316.21	0.01	5,230.44	48,531.12
DRY BOTTOM ASH PRODUCED	534.26	367.95	1,223.16	432.47	211.54	1,178.67	1,748.74	1,771.86	218.88	329.05	0.00	1,397.61	9,614.18
TOTAL ASH PRODUCED	4,668.06	3,967.71	6,216.52	2,162.34	1,046.10	5,893.23	9,743.69	9,659.28	1,092.17	1,645.27	0.00	6,628.05	58,159.29
ASH SLURCED TO POND	534.26	367.95	1,223.16	432.47	211.54	1,178.67	1,748.74	1,771.86	218.88	329.05	0.00	1,397.61	9,614.18
ASH LANDFILLED *	3,967.75	3,467.48	4,963.15	1,611.17	2,114.56	7,988.88	6,940.22	11,582.20	2,571.67	0.00	0.00	0.00	53,254.79
CE NOSPHERES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH BENEFICIAL REUSE	0.00	611.42	46.68	98.31	0.00	0.00	0.00	0.00	0.00	21.88	0.00	0.00	605.16
STRUCTURAL FILL ASH	0.00	0.00	0.00	0.00	0.00	21.36	0.00	0.00	0.00	0.00	0.00	0.00	21.36
RECLAIMED ASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH TO STRUCTURAL FILL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROGERSVILLE STATION													
DRY FLY ASH PRODUCED	14,026.63	2,913.76	11,532.68	8,756.22	8,134.45	10,398.25	20,514.56	20,342.92	20,806.56	11,998.44	11,544.36	20,211.50	190,836.57
DRY BOTTOM ASH PRODUCED	1,391.38	765.95	2,958.17	2,437.56	2,864.86	4,888.84	5,877.56	7,998.73	5,121.67	2,274.61	2,666.15	3,237.86	48,291.96
TOTAL ASH PRODUCED	16,411.97	3,529.72	14,798.86	12,187.82	10,424.31	24,004.18	26,866.22	27,953.56	25,928.23	14,173.05	14,210.74	24,119.39	247,720.82
ASH SLURCED TO POND	1,391.38	765.95	2,958.17	2,437.56	2,864.86	4,888.84	5,877.56	7,998.73	5,121.67	2,274.61	2,666.15	3,237.86	48,291.96

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 10 of 24

ASH LANDFILLED *		14,178.16	8,894.61	8,908.18	0.00	0.00	0.00	31,980.95	41,662.88	35,488.26	12,754.86	14,843.91	21,112.75	215,845.33
GYPSUM PILES		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ASH MONOFILL HOUSE		6,754.00	6,865.17	6,740.78	7,365.00	6,607.20	4,186.66	4,366.65	6,335.50	5,786.17	10,134.11	11,062.24	10,111.74	81,342.77
STRUCTURAL FILL ASH		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RECLAIMED ASH TO STRUCTURAL FILL		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMPORARY ASH STORAGE		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DEP														
Ash Produced		340,575				percent reuse		31%						
Production Ash Reused		61,397												
Ash Stored		154,644												
Ash Landfilled		742,469												
Ash to Structural Fill		21												
Reclaimed Ash for Beneficial Reuse		0												
Combined		1,343,126				percent reuse		14%						
Production Ash Reused		426,846												
BCP & WMC	Total CCP Produced	205,895	118,498	194,578	162,568	162,318	217,444	266,817	321,798	328,994	148,954	125,229	161,433	2,445,315
	Total CCP Reused	114,138	134,342	148,953	144,945	144,366	186,372	168,508	194,218	155,899	138,276	156,693	149,953	1,916,663
	% Ash Reused	77%	51%	79%	34%	49%	41%	25%	37%	51%	75%	76%	57%	47%
	% Gypsum Reuse	13.16	1548	1365	1.19%	1.24%	1.12%	89%	84%	105%	1.57%	1.77%	1.35%	1.14%
	% Total CCP Reuse	77%	109%	77%	82%	91%	79%	67%	62%	67%	114%	121%	83%	78%

2017 CCP Beneficial Utilization Statistics Memo Email re 2016 corrections.xlsx

* Ash Landfilled represents the annual tons of CCR's weighed and placed in the landfills monthly.

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 11 of 24

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 12 of 24

DEC - 2016	January	February	March	April	May	June	July	August	September	October	November	December	YTD
ALLEN STATION													
DRY FLY ASH PRODUCED	5,145	5,976	3,603	1,169	262	6,750	13,580	14,335	8,844	1,828	0	2,222	63,714
DRY BOTTOM ASH PRODUCED	1,286	1,494	901	292	65	1,688	3,395	3,584	2,211	457	0	555	15,929
TOTAL ASH PRODUCED	6,432	7,470	4,504	1,461	327	8,438	16,975	17,919	11,055	2,285	0	2,777	79,643
ASH SLUICED TO POND	1,286	1,494	901	292	65	1,688	3,395	3,584	2,211	457	0	555	15,929
ASH LANDFILLED *	9,371	8,196	6,279	1,673	0	9,098	21,039	23,095	11,850	4,484	2,104	2,695	99,882
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	0	0	203	0	0	0	0	0	203	0	0	0	407
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED TO STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
BELEWS CREEK STATION													
DRY FLY ASH PRODUCED	40,446	24,995	8,976	12,012	21,045	40,799	36,523	43,867	48,809	26,262	19,037	25,265	348,038
DRY BOTTOM ASH PRODUCED	4,999	3,089	1,109	1,485	2,601	5,043	4,514	5,422	6,033	3,246	2,353	3,123	43,016
TOTAL ASH PRODUCED	45,445	28,084	10,086	13,497	23,646	45,842	41,037	49,289	54,841	29,508	21,390	28,388	391,054
ASH SLUICED TO POND	4,999	3,089	1,109	1,485	2,601	5,043	4,514	5,422	6,033	3,246	2,353	3,123	43,016
ASH LANDFILLED *	4,052	14,440	1,141	0	0	6,226	19,685	9,803	24,295	9,013	2,402	5,863	96,922
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	18,784	20,383	22,364	12,460	12,056	30,048	25,245	34,962	29,274	27,198	35,919	21,389	290,083
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
CLIFFSIDE STATION													
DRY FLY ASH PRODUCED	5,751	5,876	97	0	5,869	18,014	24,223	16,849	7,850	5,274	8,526	21,257	119,587
DRY BOTTOM ASH PRODUCED	859	878	14	0	877	2,692	3,620	2,518	1,173	788	1,274	3,176	17,869
TOTAL ASH PRODUCED	6,611	6,754	111	0	6,746	20,706	27,842	19,367	9,023	6,062	9,801	24,433	137,456
ASH SLUICED TO POND	1,472	2,776	111	0	877	7,135	13,142	6,527	1,173	2,021	2,318	9,432	46,985
ASH LANDFILLED *	2,701	0	0	0	6,298	23,717	20,506	21,803	11,161	9,637	5,141	27,084	128,049
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	2,701	10,844	0	0	0	0	0	0	0	0	0	0	13,546
STRUCTURAL FILL ASH	852	1,015	0	0	751	3,358	3,162	3,398	1,614	981	1,816	4,050	20,997
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
MARSHALL STATION													
DRY FLY ASH PRODUCED	30,253	22,370	19,482	18,396	14,602	28,041	35,788	31,835	21,799	25,408	14,538	24,533	287,047
DRY BOTTOM ASH PRODUCED	5,339	3,948	3,438	3,246	2,577	4,948	6,316	5,618	3,847	4,484	2,566	4,329	50,655
TOTAL ASH PRODUCED	35,592	26,318	22,920	21,642	17,179	32,990	42,104	37,453	25,646	29,891	17,104	28,862	337,702
ASH SLUICED TO POND	5,339	3,948	3,438	3,246	2,577	4,948	6,316	5,618	3,847	4,484	2,566	4,329	50,655
ASH LANDFILLED *	40,743	35,814	28,184	23,300	19,212	45,926	48,723	51,149	29,464	33,032	23,569	44,833	423,950
Fly Ash Sales	0	0	0	1,029	2,750	1,786	600	769	1,026	2,492	1,462	1,361	13,275
ASH BENEFICIAL REUSE	2,229	2,152	1,564	3,587	3,666	4,226	2,690	3,721	3,441	6,211	6,846	4,407	44,739
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
Ash Produced	945,854				percent reuse		38%						
Production Ash Reused	362,050												

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 13 of 24

Ash Sluiced	156,584
Ash Landfilled	748,803
Ash to Structural Fill	20,997
Reclaimed Ash for Beneficial Reuse	0

DEP - 2016													
ASHEVILLE STATION													
DRY FLY ASH PRODUCED	5,439	5,336	2,924	1,917	2,415	3,321	6,354	7,883	3,370	2,355	4,299	5,730	51,342
DRY BOTTOM ASH PRODUCED	690	1,334	731	479	604	830	1,588	1,971	842	589	1,075	1,433	12,165
TOTAL ASH PRODUCED	6,129	6,670	3,655	2,396	3,018	4,151	7,942	9,854	4,212	2,944	5,373	7,163	63,507
ASH SLUICED TO POND	6,129	6,670	3,655	2,396	3,018	4,151	7,942	9,854	4,212	2,944	5,373	7,163	63,507
ASH LANDFILLED *	0	0	0	0	0	0	0	0	0	0	0	0	0
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	0	0	0	0	0	0	0	0	0	0	0	0	0
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED TO STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
MAYO STATION													
DRY FLY ASH PRODUCED	8,987	5,932	1,802	2,018	6,920	8,687	13,661	13,507	12,525	3,405	4,873	3,040	85,358
DRY BOTTOM ASH PRODUCED	1,139	1,483	451	505	1,730	2,172	3,415	3,377	3,131	851	1,218	760	20,232
TOTAL ASH PRODUCED	10,126	7,415	2,253	2,523	8,650	10,859	17,077	16,884	15,656	4,256	6,091	3,800	105,590
ASH SLUICED TO POND	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH LANDFILLED *	9,420	5,093	2,958	1,214	5,896	10,278	13,912	16,766	14,589	4,868	6,809	5,926	97,730
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	276	950	253	0	301	0	0	0	0	0	675	0	2,455
STRUCTURAL FILL ASH	0	67	25	42	0	138	144	136	43	44	0	0	640
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH TO STRUCTURAL FILL	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
ROXBORO STATION													
DRY FLY ASH PRODUCED	32,792	18,547	2,006	9,423	11,787	34,943	45,138	38,708	29,908	19,192	6,506	12,008	260,957
DRY BOTTOM ASH PRODUCED	4,157	4,637	502	2,356	2,947	8,736	11,284	9,677	7,477	4,798	1,626	3,002	61,198
TOTAL ASH PRODUCED	36,949	23,183	2,508	11,779	14,734	43,679	56,422	48,386	37,384	23,990	8,132	15,010	322,155
ASH SLUICED TO POND	4,157	4,637	502	2,356	2,947	8,736	11,284	9,677	7,477	4,798	1,626	3,002	61,198
ASH LANDFILLED *	29,132	23,051	4,441	7,499	13,304	38,736	54,017	46,348	40,676	34,034	9,133	36,096	336,468
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	7,475	11,931	4,132	1,919	8,762	11,428	14,099	12,038	9,082	9,975	2,558	3,833	97,231
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH TO STRUCTURAL FILL	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0

DEP

Ash Produced		491,252				percent reuse		20%							
Production Ash Reused		99,686													
Ash Sluiced		230,295													
Ash Landfilled *		434,198													
Ash to Structural Fill		640													
Reclaimed Ash for Beneficial Reuse		0													
Combined		1,437,106				percent reuse		32%							
Production Ash Reused		461,736													
DEP & DEC	Total CCP Produced	264,509	213,060	100,026	89,106	136,286	306,452	402,028	400,233	326,645	216,450	143,589	219,155	2,817,538	
Portion added 6/1/2017 as a results of a request for the backup to the summary document JWJ	Total CCP Reused	145,297	188,534	151,834	130,162	147,421	196,564	191,350	218,850	183,255	173,736	180,400	182,002	2,089,403	
	% Ash Reuse	22%	45%	62%	36%	38%	31%	22%	28%	28%	47%	73%	32%	34%	
	% Gypsum Reuse	96%	132%	228%	310%	192%	104%	75%	81%	82%	108%	173%	135%	116%	
	% Total CCP Reuse	55%	88%	152%	146%	108%	64%	48%	55%	56%	80%	126%	83%	74%	74.16%
Data from Beneficial Reuse File Server 2016 CCP Utilization DOE Index.xlsm															

* Ash Landfilled represent the moist tons of CCR's weighed and placed in the landfills monthly.

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 14 of 24

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 15 of 24

DEC - 2015	January	February	March	April	May	June	July	August	September	October	November	December	YTD
ALLEN STATION													
TOTAL ASH PRODUCED	6,704	20,818	4,101	0	3,031	15,995	45,504	16,883	3,823	899	72	695	118,524
ASH SLUICED TO POND	1,341	4,164	820	0	606	3,199	2,528	1,993	765	180	14	139	15,748
ASH LANDFILLED *	8,846	24,409	7,215	0	1,543	19,996	26,725	20,702	3,929	274	0	695	114,334
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	0	0	0	0	0	100	0	0	0	0	0	0	100
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED TO STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
BELEWS CREEK STATION													
TOTAL ASH PRODUCED	45,725	44,876	43,784	19,551	29,515	42,662	47,663	35,964	35,666	31,722	24,913	19,533	421,574
ASH SLUICED TO POND	4,875	4,936	4,816	1,937	3,247	4,693	5,243	3,281	3,923	3,489	2,668	2,149	45,258
ASH LANDFILLED *	8,054	34,166	15,195	3,042	2,824	3,030	7,449	5,731	0	4,357	4,165	351	88,365
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	15,061	11,186	26,639	30,599	30,253	49,099	34,271	35,486	31,310	21,639	21,189	29,013	335,746
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
CLIFFSIDE STATION													
TOTAL ASH PRODUCED	16,224	30,010	8,427	0	4,300	19,050	27,478	25,279	19,621	1,576	0	682	152,646
ASH SLUICED TO POND	1,905	10,112	1,739	0	-166	6,748	8,048	2,852	1,159	-40	-210	682	32,828
ASH LANDFILLED *	23,273	28,282	14,620	721	9,023	15,636	30,918	32,982	25,806	7,241	210	0	188,712
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	24	0	0	0	0	8,500	0	0	0	0	0	0	8,524
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
MARSHALL STATION													
TOTAL ASH PRODUCED	16,587	23,008	26,410	17,585	23,404	36,159	33,134	33,539	19,694	14,308	20,477	16,214	280,520
ASH SLUICED TO POND	2,488	3,451	3,962	2,638	3,511	5,424	4,970	5,031	2,954	2,146	3,071	2,432	42,078
ASH LANDFILLED *	49,968	32,959	42,631	20,495	20,590	44,189	42,051	41,155	26,811	17,470	24,934	26,654	389,908
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	0	0	288	2,504	3,114	8,950	3,015	3,591	2,988	3,612	1,439	2,084	31,565
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0

Ash Produced	973,264	percent reuse	38.63%
Production Ash Reused	375,934		
Ash Sluiced	135,912		

ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 16 of 24

Ash Landfilled	781,320
Ash to Structural Fill	0
Reclaimed Ash for Beneficial Reuse	0

DEP - 2015													
ASHEVILLE STATION													
TOTAL ASH PRODUCED	6,728	7,741	6,301	4,691	5,140	6,297	7,477	6,188	5,512	4,488	6,436	3,901	70,900
ASH SLUICED TO POND	6,728	7,741	6,301	4,691	5,140	6,297	7,477	6,188	5,512	4,488	6,436	3,901	70,900
ASH LANDFILLED *	0	0	0	0	0	0	0	6,188	5,512	4,488	6,436	3,901	26,525
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	0	0	0	0	0	0	0	0	0	0	0	0	0
STRUCTURAL FILL ASH	6,728	7,741	6,301	4,691	5,140	6,297	7,477	0	0	0	0	0	44,374
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED TO STRUCTURAL FILL ASH	45,458	30,696	65,962	59,564	63,143	78,492	10,802	0	0	0	0	0	354,117
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
MAYO STATION													
TOTAL ASH PRODUCED	17,969	12,483	5,380	16,148	17,092	17,152	18,239	16,278	10,647	6,377	8,112	2,476	148,353
ASH SLUICED TO POND	2,022	2,497	1,076	3,230	3,418	3,430	3,648	3,256	2,129	1,275	1,622	495	28,098
ASH LANDFILLED *	18,530	17,886	4,717	18,346	23,362	25,445	25,794	14,287	12,232	5,481	14,039	3,109	183,229
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	0	0	0	0	0	929	1,385	871	868	261	317	2,700	7,331
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH TO STRUCTURAL FILL	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
ROXBORO STATION													
TOTAL ASH PRODUCED	45,708	52,158	34,987	13,164	33,547	46,040	51,986	45,829	22,507	16,601	9,865	10,931	383,323
ASH SLUICED TO POND	5,142	10,432	6,997	2,633	6,709	9,208	10,397	9,166	4,501	3,320	1,973	2,186	72,665
ASH LANDFILLED *	45,434	49,669	35,967	9,694	26,878	45,782	51,645	47,136	17,570	19,155	14,890	6,323	370,142
CENOSPHERES	0	0	0	0	0	0	0	0	0	0	0	0	0
ASH BENEFICIAL REUSE	16,265	11,958	15,861	13,282	13,001	19,087	20,249	15,110	13,730	9,660	6,886	7,848	162,936
STRUCTURAL FILL ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH	0	0	0	0	0	0	0	0	0	0	0	0	0
RECLAIMED ASH TO STRUCTURAL FILL	0	0	0	0	0	0	0	0	0	0	0	0	0
TEMPORARY ASH STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0

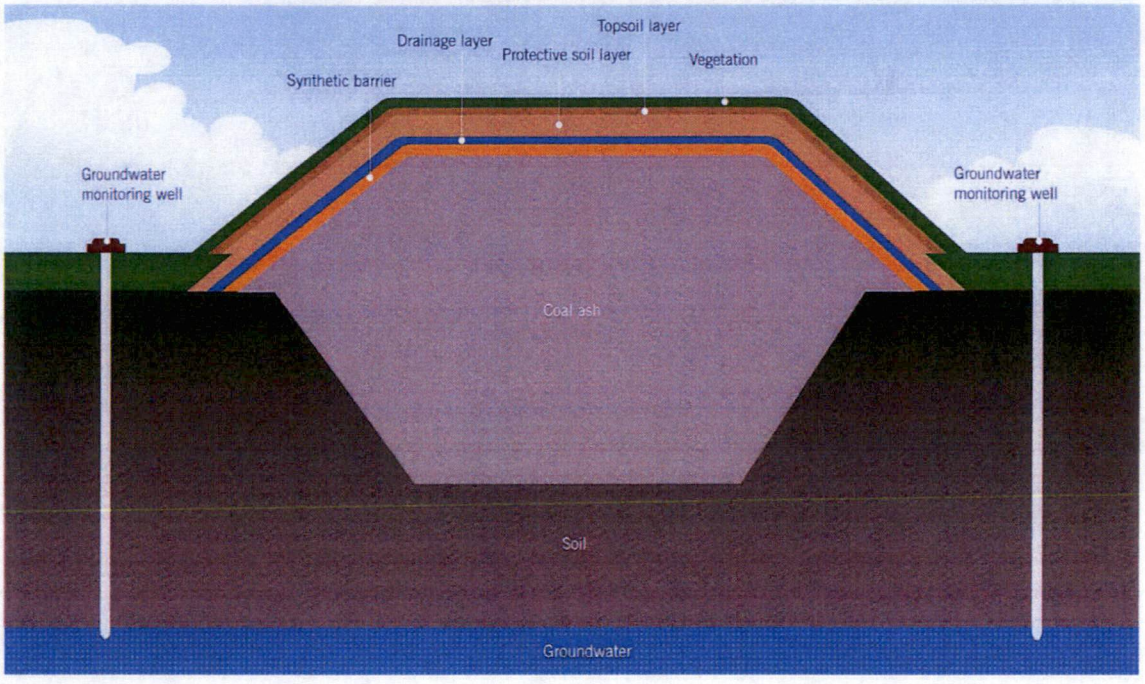
Ash Produced	602,576	percent reuse	28%

Production Ash Reused	170,267
Ash Sluiced	171,663
Ash Landfilled	579,896
Ash to Structural Fill	44,374
Reclaimed Ash for Beneficial Reuse	354,117

* Ash Landfilled represent the moist tons of CCR's weighed and placed in the landfills monthly.

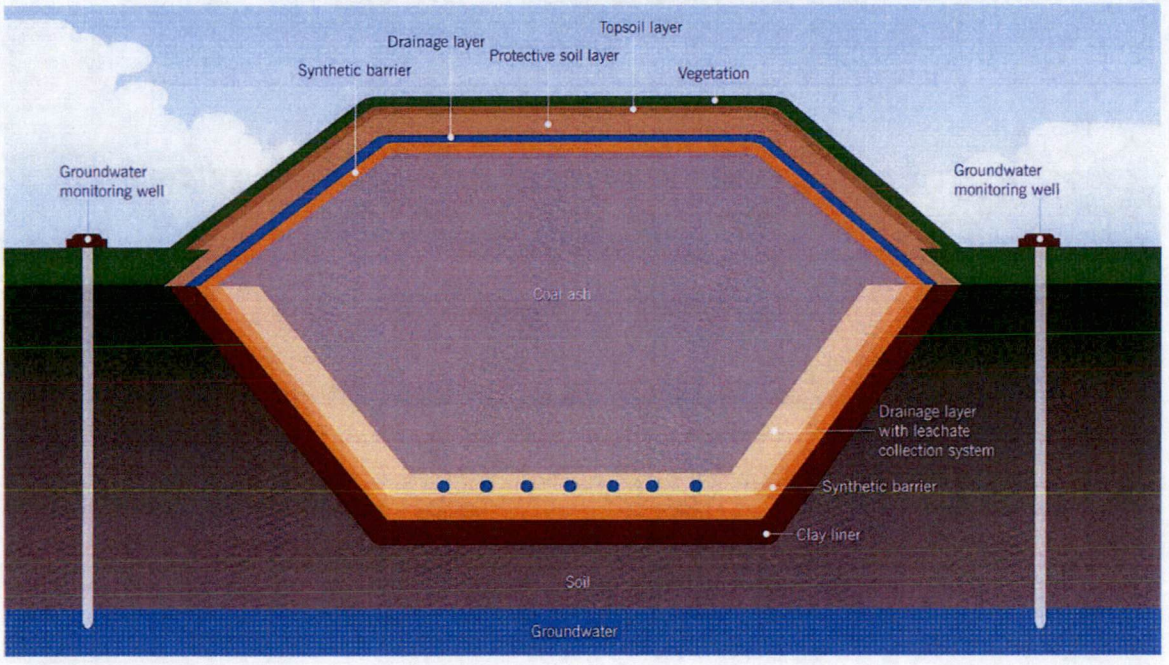
ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 17 of 24

Closure options: engineered capping system



ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 18 of 24

Closure options: fully lined landfill



ELECTRONICALLY FILED - 2018 November 8 10:34 AM - SCPSC - Docket # 2018-318-E - Page 19 of 24

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 1 of 44

Prepared by:

DUKE ENERGY.

ASHEVILLE STEAM ELECTRIC GENERATING PLANT

1982 ASH BASIN

1964 ASH BASIN

CLOSURE PLAN

OCTOBER 10, 2016

Certified by:

amec foster wheeler

Amec Foster Wheeler Environment & Infrastructure, Inc.

2030 Falling Waters Road, Suite 300

Knoxville, TN 37922

North Carolina License Number: F-1253

ASH_CLOSE_PLN

Rev. 0

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 2 of 44

Duke Energy Progress, LLC (Duke Energy) prepared this Closure Plan for the Coal Combustion Residuals (CCR) surface impoundments at the Asheville Steam Electric Generating Plant (Asheville) pursuant to the requirements of 40 C.F.R. § 257.102(b) of the Disposal of CCR from Electric Utilities rule, 80 Fed. Reg. 21302 (April 17, 2015). Amec Foster Wheeler was retained by Duke Energy to certify that this Closure Plan meets the requirements of 40 C.F.R. § 257.102. The information contained in this Closure Plan will be used to assist Duke Energy in the closure of the 1964 Ash Basin and 1982 Ash Basin (collectively, Ash Basins) located in Buncombe County, North Carolina, on property owned by Duke Energy. This Closure Plan may be amended pursuant to the requirements of 40 C.F.R. § 257.102(b)(3). Presented below are:

1. A narrative of closure activities;
2. A description of the procedures to remove CCR and decontaminate the CCR units;
3. An estimate of the in-place CCR inventory requiring closure;
4. An estimate of the largest area of the CCR units requiring a final cover (as needed);
5. A closure schedule; and
6. A written certification from a qualified professional engineer, licensed in North Carolina, that this Closure Plan meets the requirements of 40 C.F.R. § 257.102.

1 NARRATIVE OF CLOSURE ACTIVITIES

The purpose of this Closure Plan is to describe the steps required to close the Ash Basins at Asheville consistent with recognized and generally accepted good engineering practices. Closure is designed to reduce the need for long-term maintenance and control the post-closure release of constituents into environmental pathways (i.e., air, surface water, and groundwater).

The Ash Basins will be closed through the removal of CCR, and the closure will be performed pursuant to 40 C.F.R. § 257.102(c). CCR will be removed as described in the following section.

2 CCR REMOVAL AND DECONTAMINATION

The procedures to remove CCR from the Ash Basins include dewatering and utilizing appropriate equipment and methods to excavate and move the CCR to an off-site permitted landfill. Dewatering will include removal of bulk water/free liquids and interstitial/pore water (as needed) to allow for safe excavation.

The existing embankments will be breached pursuant to a North Carolina Department of Environmental Quality (NCDEQ) Dam Safety permit approval. The embankments will be re-graded so that the closure area will be filled to promote free drainage of stormwater from the closure area.

Existing appurtenant structures, such as ditches, culverts, and miscellaneous piping, will be decontaminated and abandoned in place, removed and disposed in a permitted disposal facility, or removed and placed in a beneficial use facility identified at the time of closure.

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 3 of 44

Decontamination procedures may consist of pressure washing, scrubbing, or other generally accepted decontamination procedures.

Pursuant to 40 C.F.R. § 257.102(c), closure will be complete when groundwater monitoring concentrations do not exceed the applicable groundwater protection standard established pursuant to 40 C.F.R. § 257.95(h) for constituents listed in appendix IV to 40 C.F.R. Part 257.

3 ESTIMATE OF IN-PLACE CCR INVENTORY

The volumes of CCR present in the Ash Basins were calculated and are presented in Table 1 below, pursuant to 40 C.F.R. § 257.102(b)(1)(iv). The volumes are the estimated inventory of CCR that will be open (and require closure) at one time, and the estimates are based on bathymetric surveys, historical topography, and soil borings as of December 2015. The annual surface impoundment inspections completed, pursuant to 40 C.F.R. § 257.83(b), and posted to the Duke Energy CCR website, pursuant to 40 C.F.R. § 257.107(g)(5), contain the most recent estimates of CCR material in the Ash Basins.

Table 1. Estimated In-Place CCR Inventory

Basin	Quantity of CCR (cubic yards)
1964 Ash Basin	2,113,000
1982 Ash Basin	686,000
Estimated Total	**2,799,000**

4 ESTIMATE OF LARGEST AREA REQUIRING FINAL COVER

CCR will be removed from the Ash Basins pursuant to 40 C.F.R. § 257.102(c). Therefore, no final cover system will be needed in support of closure activities.

5 CLOSURE SCHEDULE

Closure of the 1964 Ash Basin will be initiated pursuant to 40 C.F.R. § 257.102(e) and is anticipated to be completed within five years of the commencement of closure pursuant to 40 C.F.R. § 257.102(f)(1)(ii). Closure of the 1982 Ash Basin was initiated in 2015 pursuant to 40 C.F.R. § 257.102(e) and is anticipated to be completed within five years of the commencement of closure pursuant to 40 C.F.R. § 257.102(f)(1)(ii). Closure of the 1982 Ash Basin is anticipated to be completed by 2017, and the 1964 Ash Basin is anticipated to be completed by 2022.

Prior to commencing closure construction, design documents will be prepared to support applications for required local, state, and federal permits. Closure construction design documents will include construction drawings, technical specifications, and quality assurance testing work plans. The permits required for closure construction activities will be evaluated at the time of closure and are anticipated to include permits from NCDEQ and the U.S. Army Corps of Engineers. Preliminary time frames of anticipated closure activities are included below

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 4 of 44

in Table 2. We estimate that all of the closure activities for the Ash Basins will be completed by 2022.

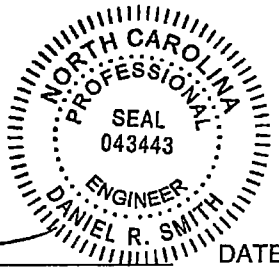
Table 2. Estimated Time Frames for Closure Activities

Closure Activity	Time Frame (years)*	
	1964 Ash Basin	1982 Ash Basin
NCDEQ Closure Plan Approval	1	-
NCDEQ Permitting Approvals (NPDES, E&SC, Air)	1	-
Dewatering and Stabilization	5	-
CCR Excavation	5	0.5
NCDEQ Dam Breach Approval	0.5	0.5

*Estimated closure activity time frames may include some overlap.

6 QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION

I, Daniel R. Smith, being a registered Professional Engineer in the state of North Carolina, do hereby certify to the best of my knowledge, information, and belief, that the information contained in this written Closure Plan dated October 10, 2016, was developed pursuant to the requirements of 40 C.F.R. § 257.102 and has been prepared in accordance with recognized and generally accepted good engineering practices.



SIGNATURE _____ DATE 10/10/16

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 5 of 44

Prepared by:

DUKE ENERGY.

H.F. LEE ENERGY COMPLEX

ACTIVE ASH BASIN

CLOSURE PLAN

OCTOBER 10, 2016

Certified by:

Geosyntec consultants

Geosyntec Consultants of NC, PC

1300 South Mint Street, Suite 300

Charlotte, North Carolina 28203

License No. C-3500

HFLEE_CLOSE_PLN

Rev. 0

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 6 of 44

Duke Energy Progress, LLC (Duke Energy) prepared this Closure Plan for the Coal Combustion Residuals (CCR) surface impoundment at the H.F. Lee Energy Complex (H.F. Lee) pursuant to the requirements of 40 C.F.R. § 257.102(b) of the Disposal of CCR from Electric Utilities rule, 80 Fed. Reg. 21302 (April 17, 2015). Geosyntec Consultants of North Carolina, PC (Geosyntec) was retained by Duke Energy to certify that this Closure Plan meets the requirements of 40 C.F.R. § 257.102. The information contained in this Closure Plan will be used to assist Duke Energy in the closure of the Active Ash Basin (Ash Basin) located in Wayne County, North Carolina, on property owned by Duke Energy. This Closure Plan may be amended pursuant to the requirements of 40 C.F.R. § 257.102(b)(3). Presented below are:

1. A narrative of closure activities;
2. A description of the procedures to remove CCR and decontaminate the CCR units;
3. An estimate of the in-place CCR inventory requiring closure;
4. An estimate of the largest area of the CCR units requiring a final cover (as needed);
5. A closure schedule; and
6. A written certification from a qualified professional engineer, licensed in North Carolina, that this Closure Plan meets the requirements of 40 C.F.R. § 257.102.

1 NARRATIVE OF CLOSURE ACTIVITIES

The purpose of this Closure Plan is to describe the steps necessary to close the Ash Basin consistent with recognized and generally accepted good engineering practices. Closure is designed to reduce the need for long-term maintenance and control the post-closure release of constituents into environmental pathways (i.e., air, surface water, and groundwater).

The Ash Basin will be closed by removal of CCR pursuant to 40 C.F.R. § 257.102(c). Procedures for CCR removal and decontamination are described in the following section.

Duke Energy is assessing the potential to site H.F. Lee for an ash beneficiation project pursuant to North Carolina General Statutes (N.C.G.S.) § 130A-309.216, as enacted by Section 1 of House Bill 630, Session Law 2016-95. If Duke Energy selects H.F. Lee for beneficiation purposes, to the extent that there is any remaining CCR in the Ash Basin after beneficiation operations have permanently ceased, the CCR will be moved to a permitted disposal facility.

2 CCR REMOVAL AND DECONTAMINATION

The procedures to remove CCR from the Ash Basin include dewatering and utilizing appropriate equipment and methods to excavate and move the CCR to a permitted disposal facility. Dewatering will include removal of bulk water/free liquids and interstitial/pore water (as needed) to allow for safe excavation and adequate compaction.

Existing appurtenant structures, such as ditches, culverts, and miscellaneous piping, will be decontaminated and abandoned in place, removed and disposed of in a permitted disposal

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 7 of 44

facility, or removed and processed at a beneficial use facility identified at the time of closure. Decontamination procedures may consist of pressure washing, scrubbing, or other generally accepted decontamination procedures.

Pursuant to 40 C.F.R. § 257.102(c), closure will be complete when groundwater monitoring concentrations do not exceed the applicable groundwater protection standard established pursuant to 40 C.F.R. § 257.95(h) for constituents listed in appendix IV to 40 C.F.R. Part 257.

3 ESTIMATE OF IN-PLACE CCR INVENTORY

The volume of CCR present in the Ash Basin was calculated and is presented in Table 1 below, pursuant to 40 C.F.R. § 257.102(b)(1)(iv). The volume is the estimated inventory of CCR that will be open (and require closure) at one time, and the estimate is based on bathymetric surveys, historical topography and soil borings as of July 2016. The annual surface impoundment inspections completed, pursuant to 40 C.F.R. § 257.83(b), and posted to the Duke Energy CCR website, pursuant to 40 C.F.R. § 257.107(g)(5), contain the most recent estimates of CCR material in the Ash Basin.

Table 1. Estimated In-Place CCR Inventory

Basin	Quantity of CCR (cubic yards)
Active Ash Basin	3,763,000

4 ESTIMATE OF LARGEST AREA REQUIRING FINAL COVER

CCR will be removed from the Ash Basin pursuant to 40 C.F.R. § 257.102(c); therefore, no final cover system will be constructed in support of closure activities.

5 CLOSURE SCHEDULE

Closure of the Ash Basin will be initiated pursuant to 40 C.F.R. § 257.102(e) and is anticipated to be completed within seven years of the commencement of closure activities. The closure time frame includes three two-year time extensions beyond the time specified in 40 C.F.R. § 257.102(f)(1)(ii) on the basis that the anticipated time required to close the Ash Basin will need to be lengthened due to:

- The Ash Basin being larger than 40 acres (estimated 130 acres); and
- The time required to develop a lined CCR placement solution in accordance with state and federal law.

Prior to commencing closure construction, design documents will be prepared to support applications for required local, state, and federal permits. Closure construction design

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 8 of 44

documents will include construction drawings, technical specifications, and quality assurance testing work plans. The permits required for closure construction activities will be evaluated at the time of closure and are anticipated to include permits from North Carolina Department of Environmental Quality (NCDEQ) and the U.S. Army Corps of Engineers. Preliminary time frames of anticipated closure activities for the Ash Basin pursuant to 40 C.F.R. § 257.102(b)(1)(vi) are included below in Table 2. Duke Energy estimates that the processing of CCR for beneficial use and closure activities for the Ash Basin will be completed by 2026. However, Duke Energy is assessing the potential to site an ash beneficiation project at H.F. Lee pursuant to N.C.G.S. § 130A-309.216. If deemed feasible, commencement of closure would not be initiated until the known final volume of CCR is removed from the CCR unit for the purpose of beneficial use pursuant to 40 C.F.R. § 257.102(e)(1)(ii). In such case, all of the closure activities for the Ash Basin will be completed by 2029. In the event H.F. Lee is selected as a beneficiation site, Duke Energy will amend this Closure Plan pursuant to the requirements of 40 C.F.R. § 257.102(b)(3).

Table 2. Estimated Time Frames for Closure Activities

Closure Activity	Time Frame (years)*
NCDEQ Closure Plan Approval	1
NCDEQ Permitting Approvals (NDPES, E&SC, Air)	1
Dewatering and Stabilization	4.5
NCDEQ Dam Decommissioning Approval	0.5
CCR Excavation	6.5

*Estimated closure activity time frames may include some overlap and do not include beneficial use activities.

6 QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION

I, Victor M. Damasceno, being a registered Professional Engineer in the state of North Carolina, do hereby certify to the best of my knowledge, information, and belief, that the information contained in this written Closure Plan dated October 10, 2016, was developed pursuant to the requirements of 40 C.F.R. § 257.102 and has been prepared consistent with recognized and generally accepted good engineering practices.

SIGNATURE _____ DATE 10 October 2016

NORTH CAROLINA PROFESSIONAL SEAL 042284 ENGINEER VICTOR M. DAMASCENO

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 9 of 44

Prepared by:

DUKE ENERGY.

MAYO STEAM ELECTRIC PLANT

ASH BASIN

FGD FORWARD FLUSH POND

FGD SETTLING POND

CLOSURE PLAN

OCTOBER 10, 2016

Certified by:

AECOM

6000 Fairview Road, Suite 200

Charlotte, NC 28210

License Number: C-2243

MAY_CLOSE_PLN

Rev. 0

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 10 of 44

Duke Energy Progress, LLC (Duke Energy) prepared this Closure Plan for the Coal Combustion Residuals (CCR) surface impoundment (Ash Basin) at the Mayo Steam Electric Plant (Mayo) pursuant to the requirements of 40 C.F.R. § 257.102(b) of the Disposal of CCR from Electric Utilities rule, 80 Fed. Reg. 21302 (April 17, 2015). URS Corporation – North Carolina (AECOM) was retained by Duke Energy to certify that this Closure Plan meets the requirements of 40 C.F.R. § 257.102. The information contained in this Closure Plan will be used to assist Duke Energy in the closure of the Ash Basin located in Person County, North Carolina, on property owned by Duke Energy. The Flue Gas Desulfurization (FGD) Forward Flush Pond and the FGD Settling Pond (collectively, FGD Ponds) are located within the Ash Basin footprint and will be included in its closure. This Closure Plan may be amended pursuant to the requirements of 40 C.F.R. § 257.102(b)(3). Presented below are:

1. A narrative of closure activities;
2. A description of the procedures to remove CCR and decontaminate the Ash Basin (as needed);
3. A description of the final cover system designed pursuant to 40 C.F.R. § 257.102(d), a description of the methods and procedures to be used to install the final cover, and a discussion of how the final cover system will achieve the performance standards specified in 40 C.F.R. § 257.102(d);
4. An estimate of the in-place CCR inventory requiring closure;
5. An estimate of the largest area of the Ash Basin requiring a final cover;
6. A closure schedule; and
7. A written certification from a qualified professional engineer, licensed in North Carolina, that this Closure Plan meets the requirements of 40 C.F.R. § 257.102.

1 NARRATIVE OF CLOSURE ACTIVITIES

The purpose of this Closure Plan is to describe the steps necessary to close the Ash Basin and FGD Ponds consistent with recognized and generally accepted good engineering practices. Closure is designed to reduce the need for long-term maintenance, control the post-closure infiltration of liquids into the in-place CCR materials, and control the post-closure release of constituents into environmental pathways (i.e., air, surface water, and groundwater).

Although, on May 18, 2016, the North Carolina Department of Environmental Quality (NCDEQ) ranked the Ash Basin "intermediate-risk," which would require it to be dewatered and excavated pursuant to the North Carolina Coal Ash Management Act of 2014, as amended (CAMA), Duke Energy is in the process of establishing the permanent replacement water supplies required under N.C.G.S. § 130A-309.211(c1) and performing the applicable dam safety repair work required under Dam Safety Order 16-01 issued by the state of North Carolina pursuant to the North Carolina Dam Safety Law of 1967, specifically N.C.G.S. § 143-215.32. Pursuant to N.C.G.S. § 130A-309.213(d)(1), upon Duke Energy's completion of these tasks within the required time frame set forth in CAMA, NCDEQ must classify the Ash Basin as low-risk, which will allow closure either pursuant to 40 C.F.R. § 257.102(c) or (d). Although CAMA charges NCDEQ with making the final determination regarding closure method, because science

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 11 of 44

supports closure of the Ash Basin by leaving the CCR in place, Duke Energy contemplates that the Ash Basin will be closed pursuant to of 40 C.F.R. § 257.102(d).

The method to close the Ash Basin and FGD Ponds in place will include: removal and treatment of the bulk water/free liquids; interstitial/pore dewatering (as needed) and treatment; stabilization of remaining CCR materials sufficient to support the final cover system; grading of in-place CCR materials to promote positive drainage (no ponding) and prevent sloughing or movement of the final cover system; installation of a final cover system, including stormwater management controls; partial lowering of the dam; and post-closure groundwater monitoring and cover system maintenance. The final cover system will be designed to minimize infiltration and erosion to meet, or exceed, the requirements of the final cover system specified in 40 C.F.R. § 257.102(d)(3)(i). Typically, this involves the installation of a low permeability barrier layer and a vegetated soil cover to protect the barrier layer. Existing embankments will be lowered pursuant to a NCDEQ Dam Safety permit approval. This lowering is intended to promote free drainage of storm water from the closure area.

2 CCR REMOVAL AND DECONTAMINATION

There may be some areas, primarily located around the perimeter of the Ash Basin and FGD Ponds, where closure-by-removal is selected in order to enhance surface drainage and/or to allow for development of future plant infrastructure or transmission. In-place CCR in those areas will typically be dewatered (if needed), excavated, and consolidated (placed) into the remaining portion of the basin, which will be graded and closed-in-place pursuant to 40 C.F.R. § 257.102(d).

Existing appurtenant structures, such as ditches, culverts, and miscellaneous piping, will be decontaminated and abandoned in place, removed and disposed in a permitted disposal facility, or removed and placed in a beneficial use facility identified at the time of closure. Decontamination procedures may consist of pressure washing, scrubbing, or other generally accepted decontamination procedures.

Pursuant to 40 C.F.R. § 257.102(c), closure will be complete when groundwater monitoring concentrations do not exceed the applicable groundwater protection standard established pursuant to 40 C.F.R. § 257.95(h) for constituents listed in appendix IV to 40 C.F.R. Part 257.

3 FINAL COVER REQUIREMENTS

The final cover system for in-place closure of the Ash Basin and FGD Ponds will be designed pursuant to 40 C.F.R. § 257.102(d). Closure of the Ash Basin and FGD Ponds will be conducted in a manner that controls, minimizes, or eliminates, to the maximum extent feasible, the post-closure infiltration of liquids into the CCR and releases of CCR, leachate, or contaminated run-off to the ground or surface waters or to the atmosphere.

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 12 of 44

The final cover system being considered is a composite (soil and geosynthetics) cover system consisting of (from top to bottom):

- A six-inch layer of soil that is capable of sustaining native plant growth;
- An 18-inch thick protective soil cover layer;
- A geocomposite drainage layer or non-woven geotextile; and
- A 40-mil thick linear low-density polyethylene geomembrane barrier.

Alternative final cover systems are also under evaluation that would meet, or exceed, the requirements specified in 40 C.F.R. § 257.102(d)(3)(ii), which make use of the latest developments in final cover technology. The final cover system will serve to reduce erosion and post-closure maintenance. Various stormwater control measures (e.g., diversion berms, channels, downslope pipes, and/or downchutes) will convey surface run-off from the cover to sediment basins (as appropriate), prior to discharge until the site is stabilized by vegetation. The design of the stormwater conveyances will include armoring and energy dissipation measures, as necessary, to control erosion and reduce maintenance and repairs.

The final cover system, with an equivalent (or lower) permeability of any bottom liner system or natural subsoils present, or permeability no greater than $1x10^{-5}$ centimeters/second, will be constructed and maintained to minimize the infiltration of precipitation. By minimizing infiltration, the final cover will reduce the potential of leachate generation. The final cover system will be graded to preclude the probability of future impoundment of water, sediment, or slurry.

The Ash Basin and FGD Ponds will be closed in a manner resulting in stable slopes that prevent the sloughing or movement of the final cover system. The grades of the final cover system will be generally slight, sufficient to promote run-off while reducing the potential for sloughing. Instability potential (sliding or sloughing) is further reduced through the selection and use of cover system materials that have adequate drainage properties and sufficient internal and interface shear strengths. Construction quality assurance procedures will be completed to confirm conformance of the installed final cover system to the design.

Upon commencement of closure of the Ash Basin and FGD Ponds, final closure is anticipated to be completed in the shortest amount of time consistent with recognized and generally accepted good engineering practices. Section 6, Closure Schedule, of this Closure Plan describes estimated time frames.

3.1 FINAL COVER SYSTEM

Pursuant to 40 C.F.R. § 257.102(d)(3)(i)(A) through (D), the final cover system will be designed and constructed to meet, at a minimum, the following criteria:

(A) The permeability of the final cover system will be less than or equal to the permeability of any bottom liner system or natural subsoils present, or a permeability no greater than 1×10^{-5} centimeters/second, whichever is less.

The final cover system options being considered for the Ash Basin and FGD Ponds will meet or exceed these criteria. The geomembrane by itself results in a

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 13 of 44

lower effective infiltration rate than the 18 inches of $1x10^{-5}$ centimeters/second soil standard.

(B) The infiltration of liquids through the Ash Basin and FGD Ponds will be minimized by the use of an infiltration layer that contains a minimum of 18 inches of earthen material.

The geomembrane component in the final cover system results in equivalent or better infiltration performance than 18 inches of earthen material. The proposed protective cover (18 inches) and vegetative layer soil will be obtained from local borrow sites and/or portions of the dams and dikes that will be lowered during closure. The gradation of the soil used in the cover will be such that it does not damage the geomembrane, provides drainage, resists erosion, and supports plant growth.

(C) The erosion of the final cover system will be minimized by the use of an erosion layer that contains a minimum of six inches of earthen material that is capable of sustaining native plant growth.

The materials proposed for the vegetative support layer in the composite cover system option, or the protective cover component of an alternate final cover system, will provide equivalent or better performance than a six-inch-thick erosion layer. In addition, and prior to the completion of closure, stormwater run-off and wastewaters generated from areas outside the Ash Basin and FGD Pond's drainage catchment (which had previously been routed through the basin when it was active) will be permanently diverted for treatment (as needed) and discharge at other locations within the site.

(D) The disruption of the integrity of the final cover system will be minimized through a design that accommodates settling and subsidence.

The materials proposed for the final cover systems will accommodate the amount of settlement and subsidence that is anticipated to be encountered during construction and post-closure. In addition, the cover grades and stormwater conveyance system grades will be designed to accommodate settlement during construction and post-closure care.

The methods and procedures used to install the final cover will include:

1. Completing necessary field characterizations and design analyses;
2. Obtaining necessary federal, state, and local permits;
3. Preparing bid documents and selecting a qualified contractor;
4. Mobilizing;
5. Installing erosion and sediment control measures;
6. Removing and treating (as needed) the bulk water/free liquid;
7. Decontaminating and abandoning in place or removing the appurtenant structures within the Ash Basin and FGD Ponds;
8. Clearing and grubbing;

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 14 of 44

9. Constructing laydown areas and access roads;
10. Interstitial/pore dewatering and treatment (as needed);
11. Grading CCR materials to achieve design cover system subgrade elevations;
12. Installing the cover system and associated stormwater management controls;
13. Stabilizing the site with appropriate vegetation and final erosion and sediment control measures;
14. Lowering of the dam; and
15. Commencing post-closure maintenance and monitoring of the site.

3.2 DRAINAGE AND STABILIZATION

Bulk water/free liquids will be removed from the Ash Basin and FGD Ponds throughout multiple phases of construction. Interstitial/pore water may be removed and treated during construction (as needed) to provide a workable surface for final cover system installation. With the diversion of wastewater and the stormwater discharged to the basin from other locations on the site, the volume of interstitial/pore water within the basin is expected to further decline over time. The dam will be lowered following the final phase of cover system installation. Combined, these measures (diversion of wastewater and stormwater, bulk dewatering, selective interstitial/pore dewatering, cover system installation, and dam lowering) will stabilize the CCR materials sufficiently to support the final cover system.

4 ESTIMATE OF IN-PLACE CCR INVENTORY

The volume of CCR present in the Ash Basin and FGD Ponds was calculated and is presented in Table 1 below, pursuant to 40 C.F.R. § 257.102(b)(1)(iv). The volume is the estimated inventory of CCR that will be open (and require closure) at one time, and the estimate is based on bathymetric surveys, historical topography, and soil borings as of December 2015. The annual surface impoundment inspections completed, pursuant to 40 C.F.R. § 257.83(b), and posted to the Duke Energy CCR website, pursuant to 40 C.F.R. § 257.107(g)(5), contain the most recent estimates of CCR material in the Ash Basin.

Table 1. Estimated In-Place CCR Inventory

Basin	Quantity of CCR (cubic yards)
Ash Basin	5,271,000
FGD Settling Pond	186,000
FGD Forward Flush Pond	43,000
Total Inventory Within Ash Basin Footprint	**5,500,000**

5 ESTIMATE OF LARGEST AREA REQUIRING FINAL COVER

Closure of the Ash Basin will be accomplished by leaving CCR in place pursuant to 40 C.F.R. § 257.102(d). The largest area of the Ash Basin that will be open (and require a final cover) at one

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 15 of 44

time is estimated to be 140 acres. The FGD Ponds are located within the Ash Basin footprint and are included in the area requiring final cover.

6 CLOSURE SCHEDULE

Closure of the Ash Basin and FGD Ponds will be initiated pursuant to 40 C.F.R. § 257.102(e) and is anticipated to be completed within seven years of the commencement of closure activities. The closure time frame includes a two-year time extension beyond the time specified in 40 C.F.R. § 257.102(f)(1)(ii) on the basis that the anticipated time required to close the Ash Basin and FGD Ponds will need to be lengthened due to:

- The Ash Basin being larger than 40 acres (estimated 140 acres);
- The amount of imported material needed to close the Ash Basin and FGD Ponds (estimated to be greater than 250,000 cubic yards);
- The volume of CCR (greater than 1.1 million cubic yards will need to be excavated and placed as grading fill);
- The volume of bulk water/free liquids to dewater (greater than 450 million gallons);
- The surrounding geology (shallow rock resulting in limited soil volume per given area, limited availability of soil meeting the permeability requirements outlined in the CCR Rule, rocks in the soil that could damage the geomembrane would need to be removed, etc.); and
- The time required, after the removal of bulk liquids, for the surface of the basin to stabilize to the point that personnel and equipment can safely access the impoundment. Given the site-specific geometry and physical characteristics of the CCR in the impoundment, the rate at which the materials will drain will likely be slow and variable. As a result, installation of instrumentation and monitoring equipment may be necessary in some instances to ensure subgrade stability is adequate, and other measures may need to be employed to stabilize the surface of the impoundment (possibly including closely-spaced well points, deep wells, trenches, etc.) in a timely manner.

The completed demonstration establishing why it is not feasible to complete closure of the Ash Basin and FGD Ponds within the five-year time frame due to factors beyond the facility's control will be prepared and placed in the facility's operating record prior to the end of any two-year period pursuant to 40 C.F.R. § 257.102(f)(2).

Prior to commencing closure construction, design documents will be prepared to support applications for required local, state, and federal permits. Closure construction design documents will include construction drawings, technical specifications, and quality assurance testing work plans. The permits required for closure construction activities will be evaluated at the time of closure and are anticipated to include permits from NCDEQ and the U.S. Army Corps of Engineers. Preliminary time frames of anticipated closure activities for the Ash Basin and FGD Ponds are included below in Table 2. Duke Energy estimates that all of the closure activities for the Ash Basin and FGD Ponds will be completed by 2026.

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 16 of 44

Table 2. Estimated Time Frames for Closure Activities

Closure Activity	Time Frame (years)*
NCDEQ Closure Plan Approval	1
NCDEQ Permitting Approvals (NDPES, E&SC, Air)	1
Dewatering and Stabilization	2.5
CCR Grading and Excavation	1.5
NCDEQ Dam Decommissioning Approval	0.5
Final Cover Installation	3.5

*Estimated closure activity time frames may include some overlap

7 QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION

I, Scott R. Ward, being a registered Professional Engineer in the state of North Carolina, do hereby certify to the best of my knowledge, information, and belief, that the information contained in this written Closure Plan dated October 10, 2016, was developed pursuant to 40 C.F.R. § 257.102 and has been prepared in accordance with recognized and generally accepted good engineering practices.

SIGNATURE _____ DATE 10/10/2016

NORTH CAROLINA PROFESSIONAL SEAL 043739 ENGINEER SCOTT R. WARD 10/10/2016

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 17 of 44

CLOSURE PLAN

CLOSURE PLAN

Mayo CCR Monofill Landfill

Submitted To: Duke Energy Progress, LLC.
526 S. Church Street
Charlotte, NC 28202

Submitted By: Golder Associates NC, Inc.
5B Oak Branch Drive
Greensboro, NC 27407

DUKE ENERGY®
PROGRESS

Distribution: Evan Andrews, PE (Duke Energy)

October 2016

Project No. 1533278

MAY_AM_CLOSE_LDFL_PLN

Golder Associates

Golder, Golder Associates and the GA globe design are trademarks of Golder Associates Corporation

Table of Contents

1.0 INTRODUCTION 1
2.0 CLOSURE PLAN 1
2.1 Overview of Closure Approach 1
2.2 Estimated Maximum Inventory of CCR 1
2.3 Largest Area Requiring Cover System 1
2.4 Closure Performance Standard 1
2.4.1 Final Cover 1
2.4.2 Alternate Final Cover 2
2.4.3 Performance Standard 2
2.5 Schedule 2
3.0 PROFESSIONAL ENGINEER CERTIFICATION 3

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 18 of 44

1.0 INTRODUCTION

This Closure Plan was prepared for the Mayo Plant (Mayo) – Coal Combustion Residuals (CCR) Monofill. This Closure Plan was prepared in accordance with 40 C.F.R. Part 257, Subpart D and is consistent with the requirements of 40 C.F.R. §257.102(b) for closure of CCR landfills. The information contained in this Closure Plan will be used to assist Duke Energy Progress, LLC (Duke Energy) in the closure of active waste units. The Mayo CCR Monofill is owned and operated by Duke Energy. The landfill is located in Person County, North Carolina on Duke property, east of the Mayo Plant and the Mayo Reservoir. Duke Energy must obtain a written certification from a qualified professional engineer, licensed in the state in which the project work is conducted, that this written Closure Plan and any amendments thereto meet the requirements of 40 C.F.R. §257.102 (see Section 3.0).

2.0 CLOSURE PLAN

2.1 Overview of Closure Approach

The purpose of the Closure Plan is to outline the steps necessary to close the landfill phases consistent with recognized and generally accepted good engineering practices. Closure is designed to minimize the need for long-term maintenance and to control the post-closure release of contaminants. The facility will be closed in accordance with the requirements of 40 C.F.R. §257.102. Closure will occur within the time frames set out in 40 C.F.R. §257.102(f). This Closure Plan may be amended in accordance with the requirements of 40 C.F.R. §257.102(b)(3).

2.2 Estimated Maximum Inventory of CCR

The current landfill design provides approximately 16,900,000 cubic yards of gross capacity as measured from the top of the protective cover soil to the top of final cover. Currently, the only active portion of the landfill is Phase 1, which has a 31.0-acre footprint and a gross capacity estimated to be 1,592,000 cubic yards.

2.3 Largest Area Requiring Cover System

The Phase 1 permitted area of 31.0 acres is currently the largest area that will need to be capped.

2.4 Closure Performance Standard

2.4.1 Final Cover

The cover system has been designed to minimize infiltration into the landfill and to resist erosion. The permeability of the least permeable layer in the final cover system is $1x10^{-12}$ centimeter per second (cm/sec). This is equal to or less than the permeability of the least permeable layer in the bottom liner system and no greater than 1×10^{-5} cm/sec.

The final cover system for the closed phase will be certified by a qualified professional engineer as being designed in accordance with the requirements of 40 C.F.R. §257.102.

With the type of waste that has been landfilled and the controlled nature of the fill placement, no decomposition of the waste material is expected; therefore, minimum, if any, settlement is expected. Due to the high allowable strain of the geomembrane and the stable nature of the waste, the final cover system will accommodate any differential settlement that may occur in the waste during the post-closure care period.

The proposed final cover system will consist of the following, from top to bottom, and will be placed over the top of the landfilled CCR materials:

- 6-inch-thick vegetated erosion layer

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 19 of 44

- 18-inch-thick protective cover soil barrier
- Geocomposite drainage layer
- 40-mil-thick double-sided textured linear low density polyethylene (LLDPE) geomembrane
- 12 inches of intermediate soil cover

2.4.2 Alternate Final Cover

No alternate final cover system is proposed.

2.4.3 Performance Standard

Closure of the facility will be conducted in a manner that minimizes the need for further maintenance and controls, and minimizes or eliminates, to the extent necessary to protect human health and the environment, the post-closure escape of uncontrolled leachate, surface runoff, or waste products to the groundwater, surface water, or the atmosphere.

The final cover system consisting of a vegetated soil layer with run-on and run-off controls will minimize the need for post-closure maintenance. The final slopes of the landfill will promote runoff. Diversion berms and downslope pipes will convey surface runoff to sediment basins designed to remove sediment prior to discharge. Vegetation will be established and, along with the diversion berms and storm water conveyance channels, will minimize erosion of the final cover system.

A low-permeability final cover system will be constructed and maintained that minimizes the infiltration of precipitation into the waste mass. By minimizing infiltration, the final cover will minimize leachate generation.

The final slopes of the landfill will not be less than 5 percent to prevent ponding.

The CCR unit will be closed in a manner that provides for slope stability to prevent the sloughing or movement of the final cover system. Both global and veneer stability analyses were performed in order to determine the minimum factors of safety against failure.

The minimum factor of safety for global static stability was found to be greater than 1.5, and the minimum factor of safety for seismic global stability was found to be greater than 1.0 in accordance with sound engineering practices for landfill final cover design.

The minimum factor of safety for static veneer stability was found to be greater than 1.5, and the minimum factor of safety for seismic veneer stability was found to be greater than 1.0 in accordance with sound engineering practices for landfill final cover design.

The final cover system will be finished within 6 months following the beginning of closure construction unless otherwise approved. If more than 6 months are necessary, steps to prevent threats to human health and the environment from the unclosed landfill unit will be undertaken.

2.5 Schedule

In accordance with 40 C.F.R. §257.102(e), the facility will begin closure activities within 30 days after the known final receipt of waste, or if the landfill has remaining capacity and there is a reasonable likelihood that the landfill will receive additional wastes, no later than 2 years after the most recent receipt of wastes. Contractor mobilization will occur during the initial 30-day period after last known receipt of waste.

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 20 of 44

In accordance with 40 C.F.R. §257.102(g), no later than the date on which closure of the CCR unit is initiated, Duke Energy will prepare a notification of intent to close the unit, which includes the certification by a qualified professional engineer for the design of the final cover system required by §257.102(d)(3)(iii).

In accordance with 40 C.F.R. §257.102(h), within 30 days following completion of closure of the CCR unit, Duke Energy shall record a notation on the deed to the landfill property stating that the property has been used as a landfill and its use is restricted under the Post-closure Plan and the post-closure care requirements as provided by 40 C.F.R. §257.104(d)(1)(iii).

Within 30 days of recording the notation, Duke Energy shall prepare a notification stating that the notation has been recorded and placed in the facility's operating record. Pursuant to 40 C.F.R. §257.106(d), Duke Energy shall send to the appropriate regulatory agency the notification of intent to close, notification of closure completion, and notification of deed notation, within 30 days of placing each notification in the operating record.

An expected schedule for closure activities is as follows:

Schedule for Closure Activities

Time	Activity
Prior to last receipt of waste	Permitting, detailed closure design, and contractor selection
Initial 30 days after last receipt of waste	Mobilization of contractor
Months 0-1 after beginning construction	Grading / preparing intermediate cover
Months 1-4 after beginning construction	Installation of geomembrane, geocomposite drainage layer, and protective cover soil and vegetation layer
Months 4-5 after beginning construction	Installation of diversion berms and downslope drainage pipes
Months 5-6 after beginning construction	Seed, fertilizer, and mulch

3.0 PROFESSIONAL ENGINEER CERTIFICATION

I, James R. DiFrancesco, being a registered Professional Engineer, in accordance with the North Carolina Professional Engineer's Registration, do hereby certify to the best of my knowledge, information, and belief, that the information contained in this report dated October 10, 2016, was prepared in accordance with the requirements of 40 C.F.R. §257.102, is true and correct, and was prepared in accordance with recognized and generally accepted good engineering practices.

The use of the word "certification" and/or "certify" in this document shall be interpreted and construed as a Statement of Professional Opinion, and is not and shall not be interpreted or construed as a guarantee, warranty, or legal opinion

GOLDER ASSOCIATES NC, INC.

Ron DiFrancesco, PE
Principal and Practice Leader

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 21 of 44

Established in 1960, Golder Associates is a global, employee-owned organization that helps clients find sustainable solutions to the challenges of finite resources, energy and water supply and management, waste management, urbanization, and climate change. We provide a wide range of independent consulting, design, and construction services in our specialist areas of earth, environment, and energy. By building strong relationships and meeting the needs of clients, our people have created one of the most trusted professional services organizations in the world.

Africa	+ 27 11 254 4800
Asia	+ 852 2562 3658
Australasia	+ 61 3 8862 3500
Europe	+ 356 21 42 30 20
North America	+ 1 800 275 3281
South America	+ 56 2 2616 2000

solutions@golder.com
www.golder.com

Golder Associates NC, Inc.
5B Oak Branch Drive
Greensboro, NC 27407 USA
Tel: (336) 852-4903
Fax: (336) 852-4904

Golder Associates

Engineering Earth's Development, Preserving Earth's Integrity

Golder, Golder Associates and the GA globe design are trademarks of Golder Associates Corporation

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 22 of 44

Prepared by:

DUKE ENERGY.

H.B. ROBINSON STEAM ELECTRIC PLANT
ASH BASIN

CLOSURE PLAN

OCTOBER 10, 2016

Certified by:

HDR

HDR Engineering, Inc. of the Carolinas
440 S. Church Street, Suite 1000
Charlotte, NC 28202
South Carolina Certificate of Authorization No. C0318

ROB_CLOSE_PLN
Rev. 0

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 23 of 44

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 24 of 44

Duke Energy Progress, LLC (Duke Energy) prepared this Closure Plan for the Coal Combustion Residuals (CCR) surface impoundment (Ash Basin) at the H.B. Robinson Steam Electric Plant (Robinson) pursuant to the requirements of 40 C.F.R. § 257.102(b) of the Disposal of CCR from Electric Utilities rule, 80 Fed. Reg. 21302 (April 17, 2015) (CCR Rule). HDR Engineering, Inc. of the Carolinas (HDR) was retained by Duke Energy to certify that this Closure Plan meets the requirements of 40 C.F.R. § 257.102. The information contained in this Closure Plan will be used to assist Duke Energy in the closure of the Ash Basin located in Darlington County, South Carolina, on property owned by Duke Energy. This Closure Plan may be amended pursuant to the requirements of 40 C.F.R. § 257.102(b)(3). Presented below are:

1. A narrative of closure activities;
2. A description of the procedures to remove CCR and decontaminate the CCR unit;
3. An estimate of the in-place CCR inventory requiring closure;
4. An estimate of the largest area of the CCR unit requiring a final cover (as needed);
5. A closure schedule; and
6. A written certification from a qualified professional engineer, licensed in South Carolina, that this Closure Plan meets the requirements of 40 C.F.R. § 257.102.

1 NARRATIVE OF CLOSURE ACTIVITIES

The purpose of this Closure Plan is to describe the steps required to close the Ash Basin at Robinson consistent with recognized and generally accepted good engineering practices. Closure of the Ash Basin will be designed to reduce the need for long-term maintenance and control the post-closure release of constituents into environmental pathways (i.e., air, surface water, groundwater).

The Ash Basin will be closed through the removal of CCR, and the closure will be performed pursuant to 40 CFR § 257.102(c). CCR will be removed as described in the following section.

2 CCR REMOVAL AND DECONTAMINATION

The procedures to remove CCR from the Ash Basin include dewatering and utilizing appropriate equipment and methods to excavate and move the CCR to a permitted on-site landfill. Dewatering will include removal of bulk water/free liquids and interstitial/pore water (as needed) to allow for safe excavation.

The existing embankment will be breached pursuant to a South Carolina Department of Health and Environmental Control (SCDHEC) Dam Safety permit approval. This breach is intended to promote free drainage of storm water from the closure area.

Existing appurtenant structures, such as ditches, culverts, and miscellaneous piping, will be decontaminated and abandoned in place, or removed and disposed in a permitted disposal facility, or placed in a beneficial use facility identified at the time of closure. Decontamination

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 25 of 44

procedures may consist of pressure washing, scrubbing, or other generally accepted decontamination procedures.

Pursuant to 40 C.F.R. § 257.102(c), closure will be complete when groundwater monitoring concentrations do not exceed the applicable groundwater protection standard established pursuant to 40 C.F.R. § 257.95(h) for constituents listed in appendix IV to 40 C.F.R. Part 257.

3 ESTIMATE OF IN-PLACE CCR INVENTORY

The volume of CCR present in the Ash Basin was calculated and is presented in Table 1 below, pursuant to 40 C.F.R. § 257.102(b)(1)(iv). The volume is the estimated inventory of CCR that will be open (and require closure) at one time, and the estimate is based on bathymetric surveys, historical topography, and soil borings as of May 2016. The annual surface impoundment inspections completed, pursuant to 40 C.F.R. § 257.83(b), and posted to the Duke Energy CCR website, pursuant to 40 C.F.R. § 257.107(g)(5), contain the most recent estimates of CCR material in the Ash Basin.

Table 1. Estimated In-Place CCR Inventory

Basin	Quantity of CCR (cubic yards)
Ash Basin	2,632,000

4 ESTIMATE OF LARGEST AREA REQUIRING FINAL COVER

Closure of the Ash Basin will be accomplished by closure-by-removal pursuant to 40 C.F.R. § 257.102(c); therefore, no final cover will be constructed in support of closure.

5 CLOSURE SCHEDULE

Closure of the Ash Basin will be initiated pursuant to 40 C.F.R. § 257.102(e) and is anticipated to be completed within seven years of the commencement of closure activities. The closure time frame includes a two-year time extension beyond the time specified in 40 C.F.R. § 257.102(f)(1)(ii) on the basis that the anticipated time required to close the Ash Basin will need to be lengthened due to:

- The Ash Basin being larger than 40 acres (estimated 72 acres); and
- The need to relocate transmission lines to close a non-CCR-Rule-regulated ash storage area subject to Consent Agreement 15 – 23 – HW with the state of South Carolina.

The completed demonstration establishing why it is not feasible to complete closure of the Ash Basin within the five-year time frame due to factors beyond the facility's control will be prepared and placed in the facility's operating record prior to the end of any two-year period pursuant to 40 C.F.R. § 257.102(f)(2).

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 26 of 44

Prior to commencing closure construction, design documents will be prepared to support applications for required local, state, and federal permits. Closure construction design documents will include construction drawings, technical specifications, and quality assurance testing work plans. The permits required for closure construction activities will be evaluated at the time of closure, and but are anticipated to include permits from SCDHEC and the U.S. Army Corps of Engineers. Preliminary time frames of anticipated closure activities are included below in Table 2. Duke Energy estimates that all of the closure activities for the Ash Basin will be completed by 2026.

Table 2. Estimated Time frames for Closure Activities

Closure Activity	Time Frame (years)*
SCDHEC Closure Plan Approval	1
SCDHEC Landfill Permit Approval	1.5
SCDHEC Permitting Approvals (NDPES, E&SC, Air)	1
Dewatering and Stabilization	1.5
SCDHEC Dam Decommissioning Approval	0.5
CCR Excavation	3

*Estimated closure activity time frames may include some overlap.

6 QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION

I, Philip A. Westmoreland being a registered Professional Engineer in the state of South Carolina, do hereby certify to the best of my knowledge, information, and belief, that the information contained in this written Closure Plan dated October 10, 2016, was developed pursuant to the requirements of 40 C.F.R. § 257.102 and has been prepared in accordance with recognized and generally accepted good engineering practices.

SIGNATURE Philip A. Westmoreland DATE Oct 10, 2016

SOUTH CAROLINA PROFESSIONAL ENGINEER LICENSE NO. 24984 PHILIP A. WESTMORELAND

SOUTH CAROLINA CERTIFICATE OF AUTHORIZATION HDR ENGINEERING, INC. OF THE CAROLINAS NO. C0318

Prepared by:

DUKE ENERGY.

ROXBORO STEAM ELECTRIC PLANT

EAST ASH BASIN

WEST ASH BASIN

EAST FGD SETTLING POND

WEST FGD SETTLING POND

FGD FORWARD FLUSH POND

POST-CLOSURE PLAN

OCTOBER 12, 2016

Certified by:

amec foster wheeler

Amec Foster Wheeler Environment & Infrastructure, Inc.

2801 Yorkmont Road Suite #100

Charlotte, NC 28208

License Number: F-1253

ROX_POST_CLOSE_PLN

Rev. 0

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 27 of 44

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 28 of 44

POST-CLOSURE PLAN

1.0 INTRODUCTION

This Post-Closure Plan was prepared for the coal combustion residuals (CCR) surface impoundments: East Ash Basin, West Ash Basin, East Flue Gas Desulfurization (FGD) Settling Pond, West FGD Settling Pond, and the FGD Forward Flush Pond (collectively, Ash Basins and FGD Ponds) at the Roxboro Steam Electric Plant owned and operated by Duke Energy Progress, LLC (Duke Energy). This Post-Closure Plan was prepared pursuant to 40 C.F.R. Part 257, Subpart D and is consistent with the requirements of 40 C.F.R. § 257.104(d) for post-closure care of CCR units. The information contained in this Post-Closure Plan will be used to assist Duke Energy in the maintenance and monitoring required during the post-closure period. The Ash Basins and FGD Ponds are located in Person County, North Carolina on Duke Energy property.

Amec Foster Wheeler Environmental and Infrastructure, Inc. – North Carolina (AMEC FW) was retained by Duke Energy to certify that this Post-Closure Plan meets the requirements of Section 257.104(d)(4) of the CCR Rule. This Post-Closure Plan may be amended pursuant to the requirements of 40 C.F.R. § 257.104.

2.0 POST-CLOSURE PLAN

2.1 Facility Contact Information

The post-closure maintenance of Ash Basins and FGD Ponds will be the responsibility of Duke Energy. Correspondence should be directed to:

Duke Energy Progress, LLC
Corporate Headquarters
526 South Church Street
Charlotte, NC 28202
800.777.9898
Email: CoalAshQuestions@duke-energy.com

2.2 Post- Closure Care Maintenance

Post-closure monitoring will be conducted semi-annually during the post-closure period. The following system components will be monitored:

- surface water management systems for signs of erosion, sedimentation, and condition;
- cover system for signs of erosion;
- cover system for evidence of settlement or subsidence;

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 29 of 44

- condition and/or presence of desired vegetation;
- condition and/or presence of undesired vegetation (distressed, dying vegetation, or woody vegetation);
- condition of the groundwater monitoring wells; and
- condition of access paths to monitoring wells.

2.2.1 Final Cover

Maintenance activities will be required to maintain the integrity and effectiveness of the final cover system. Repairs will correct effects of settlement, subsidence, erosion, or other events, and prevent run-on and run-off from eroding or otherwise damaging the final cover. The vegetative cover will be amended and fertilized as needed to maintain healthy vegetation. Depressions in the cover that pond water or otherwise impair the function of the final cover will be repaired as necessary. Areas subject to repair will be revegetated. Animal burrows and eroded areas will be filled with soil and revegetated. If vegetative cover is not adequate in a particular area, fertilizer will be applied and the area reseeded in order to reestablish vegetation. Any deep-rooted or woody vegetation that may have established itself on the cover soil will be removed.

2.2.2 Leachate Collection and Removal System

The Ash Basins and FGD Ponds are not subject to 40 C.F.R. § 257.70, therefore maintaining the integrity and effectiveness of the leachate collection and removal system does not apply.

2.2.3 Groundwater Monitoring System

The groundwater monitoring system and monitoring will be maintained pursuant to 40 C.F.R. § 257.90 through 257.98. The groundwater monitoring system will be sampled semi-annually (or as required) during the post-closure care period. The results of the analytical testing will be reported as indicated in the Groundwater Monitoring Plan. Routine well maintenance will include inspection and correction/repair of, as necessary, identification labels, concrete pads, protective covers and locks, and access paths/roads to the wells. Should a well be rendered unusable, the well will be abandoned pursuant to applicable regulations and guidelines, and a new well will be permitted and installed, as may be required.

2.3 Property Use

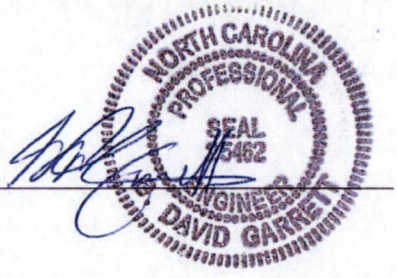
During the post-closure care period, cover systems for the Ash Basins and FGD Ponds will be maintained. Duke Energy will maintain control of, and limit access to, the facility. No post-closure use is proposed at this time. In the event the post-closure

planned use is changed, Duke Energy will amend this Post-Closure Plan to reflect such change.

No later than 60 days following the completion of the post-closure care period, Duke Energy will prepare a notification verifying that post-closure care has been completed. The notification will include a certification by a qualified professional engineer verifying that post-closure care has been completed pursuant to this Post-Closure Plan and the requirements of 40 C.F.R. § 257.104.

3.0 QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION

I, David Garrett, being a registered Professional Engineer in the State of North Carolina, do hereby certify to the best of my knowledge, information and belief, that the information contained in this written Post-Closure Plan dated October 12, 2016 was developed pursuant to the requirements of 40 C.F.R. § 257.104(d) and has been prepared pursuant to recognized and generally accepted good engineering practices.

SIGNATURE 

DATE 10-12-2016

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 30 of 44

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 31 of 44

CLOSURE PLAN

ROXBORO INDUSTRIAL LANDFILL

DUKE ENERGY – ROXBORO STEAM STATION

SEMORA, NORTH CAROLINA

Prepared for

DUKE ENERGY PROGRESS

Duke Energy
550 South Tryon Street
Charlotte, North Carolina 28202

October 7, 2016
ROX_AL_CLOSE_LDFL_PLN

arnec foster wheeler

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 32 of 44

TABLE OF CONTENTS

1.0 INTRODUCTION **1**

2.0 CLOSURE PLAN **1**

2.1 Overview of Closure Approach *1*

2.2 Estimated Maximum Inventory of CCR *1*

2.3 Largest Area Requiring Cover System *1*

2.4 Closure Performance Standard *1*

2.4.1 Final Cover 1

2.4.2 Alternate Final Cover 2

2.4.3 Performance Standards 2

2.4.4 Stability 3

2.4.5 Closure Time Frame 3

2.5 Schedule *3*

3.0 QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION **4**

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 33 of 44

1.0 INTRODUCTION

This Closure Plan was prepared for the Roxboro Steam Station – Roxboro Industrial Landfill. This Closure Plan was prepared in accordance with 40 C.F.R. Part 257, Subpart D and is consistent with the requirements of 40 C.F.R. § 257.102(b) for closure of coal combustion residuals landfills. The information contained in this Closure Plan will be used to assist Duke Energy Progress, LLC (Duke Energy) in the closure of active waste units. The Roxboro Industrial Landfill is owned and operated by Duke Energy. The landfill is located in Person County, North Carolina on Duke property, southeast of the Roxboro Steam Plant, within the drainage area of the East Ash Basin. Duke Energy must obtain a written certification from a qualified professional engineer, licensed in the state in which the project work is conducted, that this written Closure Plan and any amendments thereto meet the requirements of 40 C.F.R. § 257.102.

2.0 CLOSURE PLAN

2.1 Overview of Closure Approach

The purpose of the Closure Plan is to outline the sequence for closing the landfill phases consistent with recognized and generally accepted good engineering practices. Closure is designed to minimize the need for long term maintenance and to control the post-closure release of contaminants. The facility will be closed in accordance with the requirements of 40 C.F.R. § 257.102. Closure will occur within the time frames set out in 40 C.F.R. § 257.102(f). This Closure Plan may be amended in accordance with the requirements of 40 C.F.R. § 257.102(b)(3).

2.2 Estimated Maximum Inventory of CCR

The currently permitted landfill design for Phases 1 through 6 provides approximately 7,448,000 cubic yards of gross capacity as measured from the top of the protective cover soil to the top of final cover.

2.3 Largest Area Requiring Cover System

The largest area that will need to be capped is the area of Phases 1 through 6, which is stated as 93.0 acres in the facility's solid waste permit.

2.4 Closure Performance Standard

2.4.1 Final Cover

The cover system has been designed to reduce infiltration into the landfill and to resist erosion, and to meet the requirements of 40 C.F.R. § 257.102(d)(3)(i). The permeability of the least permeable layer (a polyethylene geomembrane) is on the order of 10^{-12} cm/s. This is equal to or

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 34 of 44

less than the permeability of the polyethylene geomembrane in the bottom liner system and no greater than 1×10^{-5} cm/sec.

The final cover system for the closed phase will be certified by a professional engineer as being designed in accordance with the requirements of 40 C.F.R. § 257.102.

With the type of waste that has been landfilled and the controlled nature of the fill placement, no decomposition of the waste material is expected, therefore minimum, if any, settlement is expected. Due to the high allowable strain of the geomembrane and the stable nature of the waste, the final cover system will accommodate any differential settlement that may occur in the waste during the post closure care period.

The proposed final cover system will consist of the following from top to bottom and will be placed over the existing intermediate soil cover:

- a 6-inch thick vegetative soil cover;
- an 18-inch thick soil cover;
- a geocomposite drainage layer; and
- a 40-mil thick double-sided textured linear low density polyethylene (LLDPE) geomembrane.

2.4.2 Alternate Final Cover

No alternate final cover system is proposed.

2.4.3 Performance Standards

Closure of the facility will be conducted in a manner that minimizes the need for further maintenance and controls, minimizes or eliminates, to the extent necessary to protect human health and the environment, the post-closure escape of uncontrolled leachate, surface runoff, or waste decomposition products to the groundwater, surface water, or the atmosphere.

The final cover system consisting of a vegetated soil layer with run-on and run-off controls will minimize the need for post-closure maintenance. The final slopes of the landfill will promote runoff. Diversion berms and downslope pipes will convey surface runoff to conveyances with non-erodible linings or, if applicable, to sediment basins designed for removal of sediment prior to discharge. A hardy stand of vegetation will be established and, along with the diversion berms and storm water conveyance channels, will minimize erosion of the final cover system.

A low-permeability final cover system will be constructed and maintained that minimizes the infiltration of precipitation into the waste mass. By minimizing infiltration, the final cover will minimize leachate generation.

The final slopes of the landfill will be five percent or greater to prevent ponding.

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 35 of 44

2.4.4 Stability

The CCR unit will be closed in a manner that provide for slope stability to prevent the sloughing or movement of the final cover system. In order to maintain stable slopes for the final cover, the internal and interface friction angles of all the components must be greater than the slope angle by a margin called a factor of safety. Since the maximum regulatory slopes are 3:1, only materials with friction angles greater than 26.6° will be used, providing a minimum factor of safety of 1.5. To ensure the stability of the vegetative support layer in the final cover system, adequate drainage must be provided to prevent the soil from becoming saturated and subject to seepage forces.

An analysis was also performed to demonstrate the stability of proposed cap section during seismic conditions. An acceptable factor of safety is 1.0 or greater to guard against slope failure. The analysis was performed in accordance with the requirements of 40 C.F.R. § 257.63 and the seismic factor of safety was found to be greater than 1.0.

2.4.5 Closure Time Frame

The final cover system will be finished within six months following the beginning of closure construction unless otherwise approved. If more than six months are necessary, steps to prevent threats to human health and the environment from the unclosed landfill unit will be undertaken.

2.5 Schedule

In accordance with 40 C.F.R. § 257.102(e), the facility will begin closure activities within 30 days after final receipt of waste, or if the landfill has remaining capacity and there is a reasonable likelihood that the landfill will receive additional wastes, no later than two years after the most recent receipt of wastes. Contractor mobilization will occur during the initial 30 day period after last receipt of waste.

In accordance with 40 C.F.R. § 257.102(f)(1), the final cover system will be completed within six months following the beginning of closure construction unless a deadline extension is approved.

In accordance with 40 C.F.R. § 257.102(g), no later than the date on which closure of the CCR unit is initiated, prepare a notification of intent to close the unit, which includes the certification by a qualified professional engineer for the design of the final cover system required by § 257.102(d)(3)(iii).

In accordance with 40 C.F.R. § 257.102(h), within 30 days of completion of closure, Duke Energy shall record a notation on the deed to the landfill property stating that the property has been used as a landfill and its use is restricted under the Closure/Post-Closure Plan and the post-closure care requirements as provided by 40 C.F.R. § 257.104(d)(1)(iii).

Within 30 days of recording the notation, Duke Energy shall prepare a notification stating that that the notation has been recorded and placed it into the facility's operating record. Pursuant

to 40 C.F.R. § 257.106(d), Duke Energy shall send to the appropriate regulatory agency the notification of intent to close, notification of closure completion, and notification of deed notation, within 30 days of placing each such notification in the operating record.

An expected schedule for closure activities is as follows:

Time	Activity
Prior to last receipt of waste	Permitting, detailed closure design and selection contractor
Initial 30 days after last receipt of waste	Mobilization of contractor
Months 0-1 after beginning construction	Grading /preparation of intermediate cover
Months 1-4 after beginning construction	Placement of soil layer and/or flexible membrane liner, and soil protective layers
Months 4-5 after beginning construction	Installation of diversion berms and downslope pipes
Months 5-6 after beginning construction	Seed, fertilize and mulch

3.0 QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION

I, Thomas B. Maier, being a registered Professional Engineer, in accordance with the North Carolina Professional Engineer's Registration do hereby certify to the best of my knowledge, information, and belief, that this report dated October 7, 2016 was prepared in accordance with the requirements of 40 C.F.R. § 257.102, is true and correct, and has been prepared in accordance with recognized and generally accepted good engineering practices.

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 36 of 44

Prepared by:

DUKE ENERGY.

L.V. SUTTON ENERGY COMPLEX

1971 ASH BASIN

1984 ASH BASIN

CLOSURE PLAN

MARCH 7, 2017

Certified by:

Geosyntec consultants

Geosyntec Consultants of NC, PC

1300 South Mint Street, Suite 300

Charlotte, North Carolina 28203

License No. C-3500

SUT_CLOSE_PLN

Rev. 1

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 37 of 44

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 38 of 44

Duke Energy Progress, LLC (Duke Energy) prepared this Closure Plan for the Coal Combustion Residuals (CCR) surface impoundments at the L.V. Sutton Energy Complex (Sutton) pursuant to the requirements of 40 C.F.R. § 257.102(b) of the Disposal of CCR from Electric Utilities rule, 80 Fed. Reg. 21302 (April 17, 2015). Geosyntec Consultants of NC, PC (Geosyntec) was retained by Duke Energy to certify that this Closure Plan meets the requirements of 40 C.F.R. § 257.102. The information contained in this Closure Plan will be used to assist Duke Energy in the closure of the 1971 Ash Basin and 1984 Ash Basin (Ash Basins) located in New Hanover County, North Carolina, on property owned by Duke Energy. This Closure Plan was originally posted to the Duke Energy operating record on October 17, 2016. The Closure Plan presented herein is a revision to the original and has been revised to update the closure initiation date and anticipated final closure date presented in Section 5. This Closure Plan may be further amended pursuant to the requirements of 40 C.F.R. § 257.102(b)(3). Presented below are:

1. a narrative of closure activities;
2. a description of the procedures to remove CCR and decontaminate the CCR units;
3. an estimate of the in-place CCR inventory requiring closure;
4. an estimate of the largest area of the CCR units requiring a final cover (as needed);
5. a closure schedule; and
6. a written certification from a qualified professional engineer, licensed in North Carolina, that this Closure Plan meets the requirements of 40 C.F.R. § 257.102.

1 NARRATIVE OF CLOSURE ACTIVITIES

The purpose of this Closure Plan is to describe the steps necessary to close the Ash Basins consistent with recognized and generally accepted good engineering practices. Closure is designed to reduce the need for long-term maintenance and control the post-closure release of constituents into environmental pathways (i.e., air, surface water, and groundwater).

The Ash Basins will be closed through the removal of CCR, and the closure will be performed pursuant to 40 C.F.R. § 257.102(c). CCR will be removed as described in the following section.

2 CCR REMOVAL AND DECONTAMINATION

The procedures to remove CCR from the Ash Basins include dewatering and utilizing appropriate equipment and methods to excavate and move the CCR to permitted off-site and on-site landfills. Dewatering will include removal of bulk water/free liquids and interstitial/pore water (as needed) to allow for safe excavation.

The existing embankments will be breached pursuant to a North Carolina Department of Environmental Quality (NCDEQ) Dam Safety permit approval. This breach is intended to promote free drainage of storm water from the closure area.

Existing appurtenant structures, such as ditches, culverts, and miscellaneous piping, will be decontaminated and abandoned in place, removed and disposed in a permitted disposal facility,

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 39 of 44

or removed and placed in a beneficial use facility identified at the time of closure. Decontamination procedures may consist of pressure washing, scrubbing, or other generally accepted decontamination procedures.

Pursuant to 40 C.F.R. § 257.102(c), closure will be complete when groundwater monitoring concentrations do not exceed the applicable groundwater protection standard established pursuant to 40 C.F.R. § 257.95(h) for constituents listed in appendix IV to 40 C.F.R. Part 257.

3 ESTIMATE OF IN-PLACE CCR INVENTORY

The volumes of CCR present in the Ash Basins were calculated and are presented in Table 1 below, pursuant to 40 C.F.R. § 257.102(b)(1)(iv). The volumes are the estimated inventory of CCR that will be open (and require closure) at one time, and the estimates are based on bathymetric surveys, historical topography, and soil borings as of March 2015. The estimates do not include any material discharged into or removed from the Ash Basins after March 2015. The annual surface impoundment inspections completed, pursuant to 40 C.F.R. § 257.83(b), and posted to the Duke Energy CCR website, pursuant to 40 C.F.R. § 257.107(g)(5), contain the most recent estimates of CCR material in the Ash Basins.

Table 1. Estimated In-Place CCR Inventory On-Site

Basin	Quantity of CCR (cubic yards)
1971 Ash Basin	3,184,000
1984 Ash Basin	2,362,000
TOTAL	**5,546,000**

4 ESTIMATE OF MAXIMUM AREA REQUIRING FINAL COVER

CCR will be removed from the Ash Basins pursuant to §257.102(c); therefore, no final cover system will be constructed in support of closure activities.

5 CLOSURE SCHEDULE

The Ash Basins ceased receiving non-CCR waste streams on July 6, 2016 (receipt of CCR waste streams ceased prior to this date). Closure of the Ash Basins initiated on July 6, 2016, within 30 days of final receipt of CCR or non-CCR waste streams pursuant to 40 C.F.R. § 257.102(e). However, limited CCR excavation operations began prior to that date. Closure of the Ash Basins will be extended due to the delayed receipt of the on-site landfill permit to construct but is anticipated to be completed by February 2020 (i.e., still within five years of the commencement of closure pursuant to 40 C.F.R. § 257.102(f)(1)(ii)). Throughout the closure process, Duke Energy will continue to evaluate and take, as appropriate, commercially reasonable measures to expedite environmentally protective closure of the Ash Basins.

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 40 of 44

Prior to commencing closure construction, design documents will be prepared to support applications for required local, state, and federal permits. Closure construction design documents will include construction drawings for closure, technical specifications, and quality testing work plans. The permits required for closure construction activities will be evaluated at the time of closure and are anticipated to include permits from the NCDEQ and the U.S. Army Corps of Engineers. Preliminary time frames for the anticipated closure activities are included below in Table 2.

Table 2. Estimated Time Frames for Closure Activities

Closure Activity	Time Frame (years)*
NCDEQ Closure Plan Approval	1
NCDEQ Permitting Approvals (NDPES, E&SC, Air)	1
Dewatering and Stabilization	4.5
NCDEQ Landfill Permit Approval	1.5
CCR Excavation	4.5
NCDEQ Dam Decommissioning Approval	0.5

*Estimated closure activity time frames may include some overlap.

6 QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION

I, Victor M. Damasceno, being a registered Professional Engineer in the state of North Carolina, do hereby certify to the best of my knowledge, information, and belief, that the information contained in this written Closure Plan dated March 7, 2017, was developed pursuant to the requirements of 40 C.F.R. § 257.102 and has been prepared in accordance with recognized and generally accepted good engineering practices.

SIGNATURE _____ DATE 7 March 2017

NORTH CAROLINA PROFESSIONAL SEAL 042284 ENGINEER VICTOR M. DAMASCENO

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 41 of 44

Prepared by:

DUKE ENERGY.

WEATHERSPOON STEAM ELECTRIC PLANT

1979 ASH BASIN

CLOSURE PLAN

OCTOBER 10, 2016

Certified by:

S&ME

S&ME, Inc.

9751 Southern Pine Boulevard

Charlotte, NC 28273

Project No. 7235-15-028

WSPN_CLOSE_PLN

Rev. 0

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 42 of 44

Duke Energy Progress, LLC (Duke Energy) prepared this Closure Plan for the Coal Combustion Residuals (CCR) surface impoundment at the Weatherspoon Steam Electric Plant (Weatherspoon) pursuant to the requirements of 40 C.F.R. § 257.102(b) of the Disposal of CCR from Electric Utilities rule, 80 Fed. Reg. 21302 (April 17, 2015). S&ME, Inc. was retained by Duke Energy to certify that this Closure Plan meets the requirements of 40 C.F.R. § 257.102. The information contained in this Closure Plan will be used to assist Duke Energy in the closure of the 1979 Ash Basin (Ash Basin) located in Robeson County, North Carolina, on property owned by Duke Energy. This Closure Plan may be amended pursuant to the requirements of 40 C.F.R. § 257.102(b)(3). Presented below are:

1. A narrative of closure activities;
2. A description of the procedures to remove CCR and decontaminate the CCR unit;
3. An estimate of the in-place CCR inventory requiring closure;
4. An estimate of the largest area of the CCR unit requiring a final cover (as needed);
5. A closure schedule; and
6. A written certification from a qualified professional engineer, licensed in North Carolina, that this Closure Plan meets the requirements of 40 C.F.R. § 257.102.

1 NARRATIVE OF CLOSURE ACTIVITIES

The purpose of this Closure Plan is to describe the steps necessary to close the Ash Basin consistent with recognized and generally accepted good engineering practices. Closure is designed to reduce the need for long-term maintenance and control the post-closure release of constituents into environmental pathways (i.e., air, surface water, and groundwater). This Closure Plan may be amended pursuant to the requirements of 40 C.F.R. § 257.102(b)(3).

The Ash Basin will be closed through the removal of CCR, and the closure will be performed pursuant to 40 C.F.R. § 257.102(c). CCR will be removed as described in the following section.

Duke Energy is assessing the potential to site Weatherspoon for an ash beneficiation project pursuant to North Carolina General Statutes (N.C.G.S.) § 130A-309.216, as enacted by Section 1 of House Bill 630, Session Law 2016-95. If Duke Energy selects Weatherspoon for beneficiation purposes, to the extent that there is any remaining CCR in the Ash Basin after beneficiation operations have permanently ceased, the CCR will be moved to a permitted disposal facility.

2 CCR REMOVAL AND DECONTAMINATION

The procedures to remove CCR from the Ash Basin include dewatering and utilizing appropriate equipment and methods to excavate and move the CCR to a permitted disposal location. Dewatering will include removal of bulk water/free liquids and interstitial/pore water (as needed) to allow for safe excavation. The existing embankments will be removed pursuant to a North Carolina Department of Environmental Quality (NCDEQ) Dam Safety permit approval. This removal is intended to promote free drainage of stormwater from the closure area.

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 43 of 44

Existing appurtenant structures, such as ditches, culverts, and miscellaneous piping, will be decontaminated and abandoned in place, removed and disposed of in a permitted disposal facility, or removed and placed in a beneficial use facility identified at the time of closure. Decontamination procedures may consist of pressure washing, scrubbing, or other generally accepted decontamination procedures.

Pursuant to 40 C.F.R. § 257.102(c), closure will be complete when groundwater monitoring concentrations do not exceed the applicable groundwater protection standard established pursuant to 40 C.F.R. § 257.95(h) for constituents listed in appendix IV to 40 C.F.R. Part 257.

3 ESTIMATE OF IN-PLACE CCR INVENTORY

The volume of CCR present in the Ash Basin was calculated and is presented in Table 1 below, pursuant to 40 C.F.R. § 257.102(b)(1)(iv). The volume is the estimated inventory of CCR that will be open (and require closure) at one time, and the estimate is based on historical topography and soil borings as of 2015. The annual surface impoundment inspections completed, pursuant to 40 C.F.R. § 257.83(b), and posted to the Duke Energy CCR website, pursuant to 40 C.F.R. § 257.107(g)(5), contain the most recent estimates of CCR material in the Ash Basin.

Table 1. Estimated In-Place CCR Inventory

Basin	Quantity of CCR (cubic yards)
Ash Basin	2,040,000

4 ESTIMATE OF LARGEST AREA REQUIRING FINAL COVER

CCR will be removed from the Ash Basin pursuant to 40 C.F.R. § 257.102(c); therefore, no final cover system will be constructed in support of closure activities.

5 CLOSURE SCHEDULE

Closure of the Ash Basin was initiated in November 2015 and is anticipated to be completed within nine years of the commencement of closure activities. The closure time frame includes two two-year time extensions beyond the time specified in 40 C.F.R. § 257.102(f)(1)(ii) on the basis that the anticipated time required to close the Ash Basin will need to be lengthened due to

- The Ash Basin being larger than 40 acres (estimated 58 acres); and
- The time required to develop a lined CCR placement solution in accordance with state and federal law.

ELECTRONICALLY FILED - 2018 November 8 10:40 AM - SCPSC - Docket # 2018-318-E - Page 44 of 44

The completed demonstration establishing why it is not feasible to complete closure of the Ash Basin within the five-year time frame due to factors beyond the facility's control will be prepared and placed in the facility's operating record prior to the end of any two-year period pursuant to 40 C.F.R. § 257.102(f)(2).

Prior to commencing closure construction, design documents will be prepared to support applications for required local, state, and federal permits. Closure construction design documents will include construction drawings, technical specifications, and quality assurance testing work plans. The permits required for closure construction activities will be evaluated at the time of closure and are anticipated to include permits from NCDEQ and the U.S. Army Corps of Engineers. Preliminary time frames of anticipated closure activities for the Ash Basin are included below in Table 2. Duke Energy estimates that all of the closure activities for the Ash Basin will be completed by 2024. However, Duke Energy is assessing the potential to site an ash beneficiation project at Weatherspoon pursuant to N.C.G.S. § 130A-309.216. If deemed feasible, commencement of closure would not be initiated until the known final volume of CCR is removed from the CCR unit for the purpose of beneficial use pursuant to 40 C.F.R. § 257.102(e)(1)(ii). In such case, all of the closure activities for the Ash Basin will be completed by 2029. In the event Weatherspoon is selected as a beneficiation site, Duke Energy will amend this Closure Plan pursuant to the requirements of 40 C.F.R. § 257.102(b)(3).

Table 2. Estimated Time Frames for Closure Activities

Closure Activity	Time Frame (year)*
NCDEQ Closure Plan Approval	1
NCDEQ Permitting Approvals (NDPES, E&SC, Air)	1
Dewatering and Stabilization	2
CCR Excavation	3
NCDEQ Dam Decommissioning Approval	0.5

*Estimated closure activity time frames may include some overlap.

6 QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION

I, Mark Anderson Taylor, being a registered Professional Engineer in the state of North Carolina, do hereby certify to the best of my knowledge, information, and belief, that the information contained in this written Closure Plan dated October 10, 2016, was developed pursuant to the requirements of 40 C.F.R. § 257.102 and has been prepared in accordance with recognized and generally accepted good engineering practices.

SIGNATURE _____ DATE 10/10/2016

NORTH CAROLINA PROFESSIONAL SEAL 10975 ENGINEER MARK A. TAYLOR

ELECTRONICALLY FILED - 2019 January 19 5:55 PM - SCPSC - Docket # 2018-318-E - Page 26 of 36

Duke Energy Progress
Breakdown of Compliance Spend by site, July 1, 2016 through September 30, 2018
All numbers presented on a system basis

Site	2016-2018 compliance spend	Type of spend	Legal justification for spend	Spend justification
Asheville	$ 120,246,520	CAMA and CCR wells; waste water management & treatment; EHS groundwater; contractor mobilization, demobilization & site preparation; truck scale installation; sluice line demolition; DOT road resurfacing; land purchase; construction of permanent power building for water management & treatment; dewatering operations; interim water treatment system; ash excavation, transportation, & storage; 1982 dam decommissioning and grading; wetland delineation report; engineering for permanent power dewatering system; ash basin closure & landfill development engineering; water management options anaylsis engineering; planning and overhead	40 CFR 257.102(b) 40 CFR 257.60 40 CFR 257.61 40 CFR 257.101(b)(1) 40 CFR 257.102(e)(1) CAMA §§ 3.(b) and 3.(c) Order Granting Motion for Partial Summary Judgment dated June 1, 2016 (13-CVS-4061)	Asheville is subject to the CCR rule provisions requiring basin closure. 40 CFR § 257.102(b) required a written closure plan by October 17, 2016. On October 12, 2018, it was determined that the 1964 ash basin at Asheville did not meet the wetlands location restriction (40 § CFR 257.61) and the uppermost aquifer location restriction (40 CFR § 257.60). This results in the Asheville 1964 ash basin being required to commence closure pursuant to 40 CFR § 257.101(b)(1). On August 30, 2016, the placement of wastestreams in the Asheville 1982 ash basin ceased and closure of the basin commenced pursuant to 40 CFR § 257.102(e)(1)(i). Pursuant to ¶ 5.e. of the Order Granting Motion for Partial Summary Judgment dated June 1, 2016 (13-CVS-4061), a written Site Analysis and Removal Plan was due by December 31, 2016. Sections 3.(b) and 3.(c) of CAMA require excavation of the Asheville basins, with the ash disposed of in either an off-site or on-site landfill. (Asheville is a high-priority site, with ash basin closure required by August 2022, which is an extended closure date allowed by the Mountain Energy Act.)
Cape Fear	$ 22,025,869	CCR wells; dam stability; EHS groundwater & permitting; ash beneficiation; dewatering operations; water treatment system; dewatering engineering plans;wetland delineation report; closure plan;basin closure engineering;planning and overheads.	Amended Order Granting Motion for Partial Summary Judgment dated June 9, 2017 (13-CVS-11032) HB 630 §§ 3.(a) and 3.(b) CAMA §§ 130A-309.214 HB 630 §§ 130A-309.216	Cape Fear is not currently subject to the CCR rule provisions requiring basin closure. However, in response to the United States Court of Appeals for the District of Columbia Circuit's August 21, 2018 decision in *USWAG v. EPA* (No. 15-1219), EPA is expected to undertake a rulemaking that would regulate inactive impoundments at closed power plants, including the basins at Cape Fear that were inactive as of the effective date of the CCR rule. Pursuant to the Amended Order Granting Motion for Partial Summary Judgment dated June 9, 2017 (13-CVS-11032), the Cape Fear site must be excavated within 10 years of receiving the applicable permits. In addition, § 3.(a) of HB 630 deems the surface impoundments at Cape Fear intermediate-risk and provides that they must be closed by excavation in accordance with § 3.(b) no later than August 1, 2028. Given these requirements, it is imperative to begin engineering and project planning at the current time to ensure completion by the required date. Closure plan preparation and submission is required by CAMA. Dewatering/water treatment are necessary to prepare ash basins for excavation. NC House Bill 630 mandated that three sites be identified for ash beneficiation (NCGS § 130A-309-216). Cape Fear was chosen as one of those sites.

ELECTRONICALLY FILED - 2019 January 19 5:55 PM - SCPSC - Docket # 2018-318-E - Page 27 of 36

Duke Energy Progress
Breakdown of Compliance Spend by site, July 1, 2016 through September 30, 2018
All numbers presented on a system basis

Site	2016-2018 compliance spend	Type of spend	Legal justification for spend	Spend justification
H.F. Lee	42,214,672	CAMA & CCR wells; dam stability; EHS groundwater & permitting; ash beneficiation; landfill; planning and overheads; bulk dewatering system; dewatering operations; dewatering engineering;wetland delineation report; closure plan development; basin closure engineering	40 CFR 257.102(b) 40 CFR 257.60 40 CFR 257.61 40 CFR 257.101(b)(1) Amended Order Granting Motion for Partial Summary Judgment dated June 9, 2017 (13-CVS-11032) HB 630 §§ 3.(a) and 3.(b) CAMA §§ 130A-309.214 HB 630 §§ 130A-309.211(c1) and .216	H.F. Lee's Active Basin is subject to the CCR rule provisions requiring basin closure, while Basins 1 through 3 are not subject to the CCR rule. 40 CFR § 257.102(b) required a written closure plan by October 17, 2016. On October 15, 2018, it was determined that the active ash basin at H.F. Lee did not meet the wetlands location restriction (40 CFR § 257.61) and the uppermost aquifer location restriction (40 CFR § 257.60). This results in the HF Lee active ash basin being required to commence closure pursuant to 40 CFR § 257.101(b)(1) on April 15, 2019. Pursuant to the Amended Order Granting Motion for Partial Summary Judgment dated June 9, 2017 (13-CVS-11032), the H.F. Lee site must be excavated within twelve years of the date of the order. In addition, § 3.(a) of HB 630 deems the surface impoundments at H.F. Lee intermediate-risk and provides that they must be closed by excavation in accordance with § 3.(b) no later than August 1, 2028. Given these requirements, it is imperative to begin engineering and project planning at the current time to ensure completion by the required date. Closure plan preparation and submission is required by CAMA. Dewatering/water treatment are necessary to prepare ash basins for excavation. NC House Bill 630 mandated that three sites be identified for ash beneficiation (NCGS § 130A-309-216). H.F. Lee was chosen as one of those sites. Pursuant to NCGS §§ 130A-309.211(c1), Duke Energy established permanent replacement water supplies to eligible households.
Mayo	$ 13,741,179	CAMA & CCR wells; dam stability; EHS groundwater & permitting; wetland delineation report;basin closure engineering; water evaluation engineering; planning and overheads	40 CFR 257.102(b) 40 CFR 257.60 40 CFR 257.101(b)(1) CAMA §§ 130A-309.213 and .214 HB 630 § 130A-309.211(c1)	Mayo is subject to the CCR rule provisions requiring basin closure. 40 CFR § 257.102(b) required a written closure plan by October 17, 2016. On October 11, 2018, it was determined that the ash basin, FGD Forward Settling Pond, and FGD Settling Pond at Mayo did not meet the uppermost aquifer location restriction (40 CFR § 257.60). This results in the Mayo ash basin, FGD Forward Settling Pond, and FGD Settling Pond being required to commence closure pursuant to 40 CFR § 257.101(b)(1)(i) no later than October 31, 2020. The Mayo plant is anticipating a low-risk ranking under CAMA in light of Duke Energy's completion of the dam safety activities required under NCGS § 130A-309.213(d)(1)b. and establishment of the permanent water supplies required under NCGS §§ 130A-309.211(c1) and 130A-309.213(d)(1)a. Engineering and project planning at the current time are needed to synchronize work between all of the coal ash sites being closed in the next 20 years, as well as to gain synergies between excavation/capping plans for all the sites. Closure plan preparation and submission is required by CAMA.

ELECTRONICALLY FILED - 2019 January 19 5:55 PM - SCPSC - Docket # 2018-318-E - Page 28 of 36

Duke Energy Progress
Breakdown of Compliance Spend by site, July 1, 2016 through September 30, 2018
All numbers presented on a system basis

Site	2016-2018 compliance spend	Type of spend	Legal justification for spend	Spend justification
Robinson	$ 6,850,071	CCR wells; storm water reroute; EHS groundwater & permitting; site preparation; planning and oversight;closure plan engineering; dewatering engineering; wetland delineation report	40 CFR 257.102(b) 40 CFR 257.60 40 CFR 257.101(b)(1) Consent Agreement dated July 17 , 2015 (15-23-HW)	Robinson is subject to the CCR rule provisions requiring basin closure. 40 CFR § 257.102(b) required a written closure plan by October 17, 2016. On October 12, 2018, it was determined that the ash basin at Robinson did not meet the uppermost aquifer location restriction (40 CFR § 257.60). This results in the Robinson ash basin being required to commence closure pursuant to 40 CFR § 257.101(b)(1)(i) no later than October 31, 2020. The Robinson plant is being excavated to a lined landfill pursuant to Consent Agreement (15-23-HW) with the South Carolina Department of Health and Environmental Control dated July 17, 2015.
Roxboro	$ 19,663,922	CAMA & CCR wells; alternate spillway; EHS groundwater & permitting; landfill cap in place activities; closure plan development	40 CFR 257.102(b) 40 CFR 257.60 40 CFR 257.61 40 CFR 257.101(b)(1) CAMA §§ 130A-309.213 and .214 HB 630 § 130A-309.211(c1)	Roxboro is subject to the CCR rule provisions requiring basin closure. 40 CFR § 257.102(b) required a written closure plan by October 17, 2016. On October 11, 2018, it was determined that the West Ash Pond at Roxboro did not meet the wetlands location restriction (40 CFR § 257.61) and the uppermost aquifer location restriction (40 CFR § 257.60). This results in the West Ash Pond at Roxboro being required to commence closure pursuant to 40 CFR § 257.101(b)(1) on April 11, 2019. On October 11, 2018, it was determined that the East Ash Pond at Roxboro did not meet the uppermost aquifer location restriction (40 CFR § 257.60). This results in the East Ash Pond being required to commence closure pursuant to 40 CFR § 257.101(b)(1)(i) no later than October 31, 2020. The East FGD Settling Pond, West FGD Settling Pond, and the FGD Forward Flush Pond have not triggered any closure requirements. The Roxboro plant is anticipating a low-risk ranking under CAMA in light of Duke Energy's completion of the dam safety activities required under NCGS § 130A-309.213(d)(1)b. and establishment of the permanent water supplies required under NCGS §§ 130A-309.211(c1) and 130A-309.213(d)(1)a. Engineering and project planning at the current time are needed to synchronize work between all of the coal ash sites being closed in the next 20 years, as well as to gain synergies between excavation/capping plans for all the sites. Closure plan preparation and submission are required by CAMA.

ELECTRONICALLY FILED - 2019 January 19 5:55 PM - SCPSC - Docket # 2018-318-E - Page 29 of 36

Duke Energy Progress
Breakdown of Compliance Spend by site, July 1, 2016 through September 30, 2018
All numbers presented on a system basis

Site	2016-2018 compliance spend	Type of spend	Legal justification for spend	Spend justification
Sutton	$ 187,736,005	CAMA & CCR wells; EHS groundwater & permitting; contractor mobilization & site preparation; rail and truck loading stations; road installation; waste water treatment plant; tipping fees;leachate removal; ash excavation & processing; construction of on-site landfill; planning and overheads; closure plan; waste water engineering;landfill engineering	40 CFR 257.101(b) 40 CFR 257.102(e)(1) CAMA §§ 3.(b) and 3.(c) Order Granting Motion for Partial Summary Judgment dated June 1, 2016 (13-CVS-11032)	Sutton is subject to the CCR rule provisions requiring basin closure. 40 CFR § 257.102(b) required a written closure plan by October 17, 2016. On July 6, 2016, the placement of wastestreams in the Sutton 1971 Basin and 1984 Basin ceased and closure of the basins commenced pursuant to 40 CFR § 257.102(e)(1)(i). Pursuant to ¶ 5.e. of the Order Granting Motion for Partial Summary Judgment dated June 1, 2016 (13-CVS-11032), a written Site Analysis and Removal Plan was due by December 31, 2016. Sections 3.(b) and 3.(c) of CAMA require excavation of the Sutton basins, with the ash disposed of in either an off-site or on-site landfill. (Sutton is a high-priority site, with ash basin closure required by August 1, 2019.)
Weatherspoon	$ 21,656,193	Road preparation and construction; equipment procurement; beneficiation; dewatering engineering plans; closure plan development; CAMA & CCR wells; dam stability; EHS groundwater & permitting; planning and overheads	40 CFR 257.102(b) 40 CFR 257.101(b)(2) Amended Order Granting Motion for Partial Summary Judgment dated June 9, 2017 (13-CVS-11032) HB 630 §§ 3.(a) and 3.(b) CAMA § 130A-309.214	Weatherspoon is subject to the CCR rule provisions requiring basin closure. 40 CFR § 257.102(b) required a written closure plan by October 17, 2016. It was determined that the 1979 ash basin at Weatherspoon did not meet the requirements of 40 C.F.R. § 257.73 (e)(1), resulting in the basin being required to commence closure pursuant to 40 CFR § 257.101(b)(2). On December 13, 2017, Duke Energy posted the initial notice of intent to close the Weatherspoon 1979 ash basin on its publicly accessible Web site. Pursuant to the Amended Order Granting Motion for Partial Summary Judgment dated June 9, 2017 (13-CVS-11032), the Weatherspoon site must be excavated within twelve years of the date of the order. In addition, § 3.(a) of HB 630 deems the surface impoundments at Weatherspoon intermediate-risk and provides that they must be closed by excavation in accordance with § 3.(b) no later than August 1, 2028. Given these requirements, it is imperative to begin engineering and project planning at the current time to ensure completion by the required date. Closure plan preparation and submission is required by CAMA.
Total - All Sites	**$ 434,134,431**			

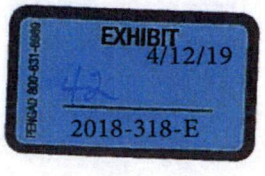
THE STATE OF SOUTH CAROLINA
BEFORE THE DEPARTMENT OF HEALTH AND ENVIRONMENTAL CONTROL

IN RE: DUKE ENERGY PROGRESS, INC.
H.B. ROBINSON STEAM ELECTRIC PLANT
DARLINGTON COUNTY

CONSENT AGREEMENT
15 – 23 – HW

This Consent Agreement is entered into between the South Carolina Department of Health and Environmental Control (SCDHEC or the Department) and Duke Energy Progress, Inc. (Duke Energy) with respect to the investigation and remediation of the inactive 1960 ash storage area at the H.B. Robinson Steam Electric Plant located at 3581 W. Entrance Road, Hartsville, South Carolina (Tax Map Number 018-00-02-001). The "Site" shall include the inactive 1960 ash storage area and all areas where ash, other coal combustion residuals, or their constituents, including contaminants, (collectively Coal Combustion Residuals or CCR or ash) may have potentially migrated from the 1960 ash storage area, collectively referred to as the "Site" as depicted on Exhibit A.

Duke Energy is entering into this Consent Agreement to assess and address any release or threat of release of Coal Combustion Residuals or other pollutants from the Site to the environment and to provide for the final disposition of the Site. Duke Energy will take all necessary steps in compliance with all environmental laws to prevent future releases from the Site. In the interest of resolving the matters herein without delay, Duke Energy agrees to the entry of this Consent Agreement without litigation and without the admission or adjudication of any issue of fact or law, except for purposes of enforcing this agreement. Duke Energy agrees that this Consent Agreement shall be deemed an admission of fact and law only as necessary for enforcement of this Consent Agreement by the Department or in subsequent actions relating to this Site by the Department.



FINDINGS OF FACT

Based on information known by the Department, the following findings of fact are asserted by the Department for purposes of this Consent Agreement:

1. Duke Energy Progress, Inc. owns and operates both:

   a. The H.B. Robinson Steam Electric Plant (Robinson Plant) located approximately 4.5 miles north of Hartsville, Darlington County, South Carolina. Development of the Robinson Plant facility began in the late 1950s when Black Creek was impounded to create Lake Robinson. Shortly thereafter, the 177 MW coal-fired unit (Unit 1) began commercial operation in 1960. That unit was retired in October 2012. A 710 MW nuclear unit began operation at the site in 1971 and continues to operate. The Tax Map Identification is 018-00-02-001.

   b. The Darlington Plant is located adjacent to the Robinson Plant in Darlington County, South Carolina. The Darlington Plant consists of 13 combustion turbine units and began operation in 1974. Coal has never been used as a fuel at the Darlington Plant. The Tax Map Identification is also 018-00-02-001.

2. The Robinson Plant coal ash management facilities include one ash basin (State Identification Number D3514) located northwest of the fossil and nuclear units; and a 1960 ash storage area located south of the permitted ash basin. The 1960 ash storage area was created in 1960, and received ash from Unit 1 until the permitted ash basin was constructed in the mid-1970s. The 1960 ash storage area covers a surficial area measuring approximately 25 acres with an estimated ash thickness ranging from 6 to 16 feet.

3. Preliminary Site assessment indicates that the preferred disposition of the CCR from the Site is in a South Carolina permitted Class 3 solid waste disposal facility located on the Darlington Plant site and/or the Robinson Site. However, if detailed closure planning

determines that beneficial reuse or disposal in an off-site waste disposal facility is a superior option, then Duke Energy may choose to pursue such options with the consent of the Department.

4. CCR located at the Site lies in an electric transmission corridor, and removal of the ash will require relocation of the transmission line, including its supporting structures. In order to relocate the transmission towers and structures in clean soil, the CCR must be removed in phases, with the first phase consisting of excavation, removal, and disposal of CCR in the area to which the transmission line will be relocated (the Sub-Site). The first phase will require confirmatory sampling to assure the CCR has been removed before erecting the transmission towers and supporting structures in this area. Any groundwater remediation needed for the Sub-Site shall be completed once CCR has been removed from the entire 1960 ash storage area.

CONCLUSIONS OF LAW

The Department has the authority to implement and enforce laws and related regulations pursuant to the South Carolina Hazardous Waste Management Act, S.C. Code Ann. §44-56-10, et seq. (Rev. 2002 and Supp. 2014), the Pollution Control Act, S.C. Code Ann. §48-1-10 et seq. (Rev. 2008 and Supp. 2014) and the South Carolina Solid Waste Policy and Management Act, S.C. Code Ann. §44-96-10, et seq. (Rev. 2002 and Supp. 2014). These Acts authorize the Department to issue orders; assess civil penalties; conduct studies, investigations, and research to abate, control and prevent pollution; and to protect the health of persons or the environment.

NOW, THEREFORE IT IS AGREED, with the consent of Duke Energy and the Department, and pursuant to the South Carolina Hazardous Waste Management Act, the Pollution Control Act, and/or the Solid Waste Policy and Management Act, that Duke Energy shall:

1. Submit an application to construct the Class 3 solid waste disposal facility to the Department no later than April 1, 2016. If a Class 3 solid waste disposal facility cannot be permitted at the Darlington Electric Power Plant and/or the Robinson Plant within five (5) years of the effective date of this agreement, Duke Energy shall dispose of the CCR by another Department approved method.

2. Dispose of all CCR at the Site within a South Carolina permitted Class 3 solid waste disposal facility located at the Darlington Electric Power Plant and/or the Robinson Plant, and complete disposal within eight (8) years following the execution of this Consent Agreement.

3. Within ninety (90) days of receipt of a final and non-appealable permit to construct a Class 3 solid waste disposal facility, commence construction of said solid waste disposal facility and submit to the Department for review and approval, an Ash Removal Plan for the Site. The Ash Removal Plan shall include a time schedule for implementation of all major activities required by the Plan. The Ash Removal Plan must include, but is not limited to, characterization of the ash, provisions for the safe removal of the ash, and management of storm water during the project. The Ash Removal Plan shall also include an evaluation of any stability issues expected to be encountered during ash removal activities. The Ash Removal Plan shall address the impacts to the existing transmission lines and municipal sewer lines and the plans to relocate these utilities as part of the project. Any comments generated through the Department's review of the Ash Removal Plan must be addressed in writing by Duke Energy within fifteen (15) days of Duke Energy's receipt of said comments. Upon the Department's approval of the Ash Removal Plan and the time schedule for implementation thereof, the Ash Removal Plan and schedule shall be incorporated herein and become an enforceable part of this Consent Agreement. The implementation schedule must include the calendar date when all ash will be removed from the Site, not to exceed eight (8) years as outlined in item 2. above.

4. Submit, along with but under separate cover from the Ash Removal Plan, a Health and Safety Plan (HASP) consistent with Occupational Safety and Health Administration regulations. The HASP shall be submitted to the Department in the form of one (1) electronic copy (pdf. format). Duke Energy agrees the HASP is submitted to the Department for informational purposes only. The Department expressly denies any liability that may result from Duke Energy's implementation of the HASP. Begin implementation of the Ash Removal Plan described in paragraph 3. within fifteen (15) days of Duke Energy's receipt of the Department's written approval of the Ash Removal Plan and all required permits, whichever is later, provided Duke Energy submits timely applications for any necessary permits.

5. Upon completion of the work approved at the Site or Sub-Site in accordance with the Ash Removal Plan, submit an Ash Removal Report to the Department. The Ash Removal Report shall summarize the activities taken during implementation of the Ash Removal Plan and shall contain appropriate documentation that ash has been removed from the Site or Sub-Site and properly disposed of in accordance with the Ash Removal Plan.

6. Within thirty (30) days of approval of the Ash Removal Report(s), submit an Assessment Plan to the Department. The Assessment Plan shall include, but is not limited to, the following: a description of work needed for the delineation of the vertical and horizontal extent of any contamination, including an assessment of surface water, groundwater, and soil underlying the Site; a conceptual site model to ensure assessment of all potential risks to human health and the environment; and a schedule for implementation.

7. Upon completion of the activities outlined in the approved Assessment Plan, within sixty (60) days submit to the Department an Assessment Report summarizing the findings of the investigations performed pursuant to the Assessment Plan, including an evaluation of all risks to human health and the environment. The Department shall review the Assessment Report to determine completion of the field investigation and sufficiency of

the documentation. If the Department determines that additional field investigation is necessary, Duke Energy shall conduct additional field investigation to complete such task. Alternatively, if the Department determines the field investigation to be complete, but the conclusions in Duke Energy's Assessment Report are not approved, Duke Energy shall submit a Revision to the Assessment Report within thirty (30) days after receipt of the Department's disapproval. The Revision shall address the Department's comments.

8. Within sixty (60) days of approval of all Assessment Reports, submit to the Department a Closure Plan which details the actions to be taken for the final disposition of the Site, and evaluates the need for additional remediation of soils, surface water and groundwater. If remedial actions are necessary, Duke Energy shall also submit to the Department for approval a Remedial Plan, which includes a proposed remedy, justification for the proposed remedy, the design of the proposed remedy and a schedule for implementation. The schedule of implementation must extend through full completion of the remedy. The Closure Plan and, if necessary, the Remedial Plan shall be based upon the results of the field investigation, ash removal activities and the following seven (7) criteria:

   a. Overall protection of human health and the environment;

   b. Compliance with applicable or relevant and appropriate standards;

   c. Long-term effectiveness and permanence;

   d. Reduction of toxicity, mobility or volume;

   e. Short-term effectiveness;

   f. Implementability; and

   g. Costs.

9. Address any comments generated through the Department's review of the Closure Plan and any required Remedial Plan in writing within fifteen (15) days of Duke Energy's receipt of said comments. This fifteen (15) day deadline may be extended by mutual agreement of the parties if the comment resolution requires extensive revision, such as

reengineering. Upon Department approval of the Closure Plan, Remedial Plan and the implementation schedule, the Closure Plan, Remedial Plan, and implementation schedule shall be incorporated herein and become an enforceable part of this Consent Agreement.

10. Begin to implement the Closure Plan and the Remedial Plan within forty-five (45) days of the Department's approval of the Plans; and thereafter, take all necessary and reasonable steps to ensure timely completion of the Plans.

11. Submit to the Department a written monthly progress report within thirty (30) days of the execution of this Consent Agreement and by the last business day of every month thereafter until completion of the work required under this Consent Agreement. The progress reports shall include the following: (a) a description of the actions which Duke Energy has taken toward achieving compliance with this Consent Agreement during the previous month; (b) results of sampling and tests, in summary format received by Duke Energy during the reporting period; (c) description of all actions which are scheduled for the next month to achieve compliance with this Consent Agreement, and other information relating to the progress of the work as deemed necessary or requested by the Department; and (d) information regarding the percentage of work completed and any delays encountered or anticipated that may affect the approved schedule for implementation of the terms of this Consent Agreement, and a description of efforts made to mitigate delays or avoid anticipated delays.

12. Prepare all Plans and perform all activities under this Consent Agreement following appropriate DHEC and EPA guidelines. All Plans and associated reports, with the exception of the Monthly Reports required by paragraph 12 and the HASP required by paragraph 4. above, shall be prepared in accordance with industry standards and endorsed by a Professional Engineer (P.E.) and/or Professional Geologist (P.G.) duly-licensed in South Carolina. Unless otherwise requested, one (1) paper copy and one (1) electronic copy (pdf. format) of each document prepared under this Consent Agreement shall be

submitted to the Department's Project Manager. Unless otherwise directed in writing, all correspondence, work plans and reports should be submitted to the Department's Project Manager at the following address:

Tim Hornosky
South Carolina Department of Health and Environmental Control
Bureau of Land and Waste Management
2600 Bull Street
Columbia, South Carolina 29201
hornostr@dhec.sc.gov

13. Reimburse the Department on a quarterly basis, for all past, present and future costs, direct and indirect, incurred by the Department pursuant to this Consent Agreement and as provided by law. Oversight Costs include, but are not limited to, the direct and indirect costs of negotiating the terms of this Consent Agreement, reviewing plans and reports, supervising corresponding work and activities, and costs associated with public participation. The Department shall provide documentation of its Oversight Costs in sufficient detail so as to show the personnel involved, amount of time spent on the project for each person, expenses, and other specific costs. Payments are due to the Department within thirty (30) days of the date of the Department's invoice; however, it is not a violation of this Consent Agreement if late payment is cured within thirty (30) additional days.

14. Meet with the Department's Project Manager at least quarterly to discuss progress toward schedule requirements and to anticipate any schedule delays.

15. Notify the Department in writing at least five (5) days before the scheduled deadline if any event occurs which causes or may cause a delay in meeting any of the above-scheduled dates for completion of any specified activity pursuant to this Consent Agreement. Duke Energy shall describe in detail the anticipated length of the delay, the precise cause or causes of delay, if ascertainable, the measures taken or to be taken to

prevent or minimize the delay, and the timetable by which Duke Energy proposes that those measures will be implemented. The Department shall provide written notice to Duke Energy as soon as practicable that a specific extension of time has been granted or that no extension has been granted. An extension shall be granted for any scheduled activity delayed by an event of *force majeure* which shall mean any event arising from causes beyond the control of Duke Energy that causes a delay in or prevents the performance of any of the conditions under this Consent Agreement including, but not limited to: a) acts of God, fire, war, insurrection, civil disturbance, explosion; b) adverse weather conditions that could not be reasonably anticipated causing unusual delay in transportation and/or field work activities; c) restraint by court order or order of public authority; d) inability to obtain, after exercise of reasonable diligence and timely submittal of all required applications, any necessary authorizations, approvals, permits, or licenses due to action or inaction of any governmental agency or authority, or litigation staying or reversing permit issuance or other governmental agency approvals; and e) delays caused by compliance with applicable statutes or regulations governing contracting, procurement or acquisition procedures, despite the exercise of reasonable diligence by Duke Energy. Events which are not *force majeure* include by example, but are not limited to, unanticipated or increased costs of performance, changed economic circumstances, normal precipitation events, or failure by Duke Energy to exercise due diligence in obtaining governmental permits or performing any other requirement of this Consent Agreement or any procedure necessary to provide performance pursuant to the provisions of this Consent Agreement. Any extension shall be granted at the sole discretion of the Department, incorporated by reference as an enforceable part of this Consent Agreement, and thereafter, be referred to as an attachment to the Consent Agreement.

16. Upon Duke Energy's successful completion of the terms of this Consent Agreement, submit to the Department a written Final Report. The Final Report shall contain all necessary documentation supporting Duke Energy's remediation of the Site and successful and complete compliance with this Consent Agreement. Once the Department has approved the Final Report, the Department will provide Duke Energy a written approval of completion that provides Covenant Not to Sue to Duke Energy for the response actions specifically covered in this Consent Agreement, approved by the Department and completed in accordance with the approved work plans and reports.

17. Notwithstanding any other provision of this Consent Agreement, including the Covenant Not to Sue, the Department reserves the right to require Duke Energy to perform any additional work at the Site or to reimburse the Department for additional work if Duke Energy declines to undertake such work, if: (i) conditions at the Site, previously unknown to the Department, are discovered after completion of the work approved by the Department pursuant to this Consent Agreement and warrant further assessment or remediation to address a release or threat of a release in order to protect human health or the environment, or (ii) information is received, in whole or in part, after completion of the work approved by the Department pursuant to this Consent Agreement, and these previously unknown conditions of this information indicate that the completed work is not protective of human health and the environment. In exigent circumstances, the Department reserves the right to perform the additional work and Duke Energy will reimburse the Department for the work.

18. In consideration for the Department's Covenant Not to Sue, Duke Energy agrees not to assert any claims or causes of action against the Department arising out of response activities undertaken at the Site, or to seek any other costs, damages or attorney's fees from the Department arising out of response activities undertaken at the Site except for those claims or causes of action resulting from the intentional or grossly negligent acts or

omissions of the Department. However, Duke Energy reserves all available defenses, not inconsistent with this Consent Agreement, to any claims or causes of action asserted against Duke Energy arising out of response activities undertaken at the Site by the Department.

19. Employees of the Department, their respective consultants and contractors will not be denied access during normal business hours or at any time work under this Consent Agreement is being performed or during any environmental emergency or imminent threat situation, as determined by the Department or as allowed by applicable law.

IT IS AGREED THAT this Consent Agreement shall be binding upon and inure to the benefit of Duke Energy and its officers, directors, agents, receivers, trustees, heirs, executors, administrators, successors, and assigns and to the benefit of the Department and any successor agency of the State of South Carolina that may have responsibility for and jurisdiction over the subject matter of this Consent Agreement. Duke Energy may not assign it rights or obligations under this Consent Agreement without the prior written consent of the Department.

IT IS FURTHER AGREED that failure to meet any deadline or to perform the requirements of this Consent Agreement without an approved extension of time and failure to timely cure as noted below, may be deemed a violation of the Pollution Control Act, the South Carolina Hazardous Waste Management Act and/or the Solid Waste Management and Policy Act, as amended. Upon ascertaining any such violation, the Department shall notify Duke Energy in writing of any such deemed violation and that appropriate action may be initiated by the Department in the appropriate forum to obtain compliance with the provisions of this Consent Agreement and the aforesaid Acts. Duke Energy shall have thirty (30) days to cure any deemed violations of this Consent Agreement. Applicable penalties may begin to accrue after issuance of the Department's determination that the alleged violation has not been cured during that thirty (30) day period.

(Signature Page Follows)

FOR THE SOUTH CAROLINA DEPARTMENT OF HEALTH AND ENVIRONMENTAL CONTROL

Elizabeth A. Dieck
Director of Environmental Affairs

Date: 7/17/2015

Daphne G. Neel, Chief
Bureau of Land and Waste Management

Date: 7/16/15

Van Keisler, P.G., Director
Division of Compliance and Enforcement

Date: 7-16-15

Reviewed By:

Attorney
Office of General Counsel

Date: 7/16/15

WE CONSENT:

DUKE ENERGY PROGRESS, INC.

(Signature)

Date: July 15, 2015

John Elnitsky, Senior V.P.
Please clearly print name and title

LOCATION MAP

GRAPHIC SCALE - IN FEET

NOTES:

1. AERIAL PHOTOGRAPH SOURCE IS GOOGLE MAPS WITH PHOTOGRAMMETRY DATE OF 2013.
2. APPROXIMATE LIMITS SHOWN FOR THE ROBINSON 1960 ASH STORAGE AREA ARE BASED ON DELINEATION BY AMEC FOSTER WHEELER FROM FIELD INVESTIGATION PERFORMED IN 2014

DUKE ENERGY

Amec Foster Wheeler Environment & Infrastructure, Inc.

amec foster wheeler

EXHIBIT A
DUKE ENERGY - H. B. ROBINSON PLANT

1960 ASH STORAGE AREA
LOCATION MAP

AS NOTED

EXHIBIT A

Exhibit 3.4.0: Footnotes of DEP ARO Cash Flows Response to SCORS Interrogatory 10-08

Duke Energy Progress
Ash Management ARO Cash Flows Summary
Detail Tab Footnotes
as of September 30, 2018

Note: Certain types of actual amounts may not be in the same categories as forecasted amounts

a. Basin Closure includes a contingency estimate for discrete items
b. Coal Combustion Products (CCP) Basin Support Projects estimate reflects CCR related support projects affecting the timing or method of closure (ex. Dam stability projects)
c. EHS - Environmental, Health and Safety: estimate includes well installation, well sampling (goundwater monitoring), bottled water and permanent water supplies
d. Post-Closure Maintenance - 30 years of required costs post-closure
e. Landfill Closure - estimated cash flows for landfill AROs initially recorded before CAMA and CCR (not included in Cost of Removal depreciation rates)
f. Remaining Current Year Forecast - includes contingency
g. Inflation Impacts - compounded inflation impacts

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 93 of 168

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 94 of 168

Exhibit 3.4.0: Summary of DEP ARO Cash Flows Response to SCORS Interrogatory 10-08									
Duke Energy Progress									
Ash Management ARO Cash Flows Summary									
System Level									
As of 9/30/18									
w/ Inflation									
	Total Project Costs (2015+)	Total Costs Incurred 1/1/15 - 9/30/18	2015	2016	2017	1/1 - 9/30/18	Total CF Forecast	10/1 - 12/31/18	2019
DEP									
Operating									
Asheville	$ 452,038,793	$ 191,934,196	$ 24,187,676	$ 82,788,175	$ 40,931,030	$ 44,027,315	$ 260,104,597	$ 22,261,993	$ 64,563,236
Mayo	206,749,586	25,384,168	7,342,989	7,524,374	5,880,434	4,636,371	181,365,418	9,165,451	14,317,607
Roxboro	349,803,401	34,070,691	7,806,769	12,563,556	7,167,110	6,533,256	315,732,710	6,366,469	16,220,154
Total Operating Plants	1,008,591,780	251,389,055	39,337,434	102,876,105	53,978,574	55,196,942	749,360,288	37,793,913	95,100,997
Retired									
Cape Fear	504,918,488	33,631,199	7,705,330	8,346,981	6,815,029	10,763,860	471,287,289	18,325,181	116,714,502
HF Lee (NC)	568,383,919	54,775,180	7,260,508	13,498,675	13,416,419	20,599,578	513,608,739	21,923,632	120,532,835
Robinson (SC)	179,561,777	11,431,675	2,581,604	3,834,014	2,090,145	2,925,911	168,130,102	10,866,681	34,194,657
Sutton	493,219,171	255,525,554	37,189,549	79,669,346	104,689,533	33,977,126	237,693,617	19,844,924	75,735,346
Weatherspoon	209,724,346	28,287,429	4,631,236	4,489,006	9,438,277	9,728,910	181,436,918	7,036,705	17,895,496
Total Retired Plants	1,955,807,702	383,651,037	59,368,227	109,838,022	136,449,403	77,995,385	1,572,156,665	77,997,123	365,072,836
Total Duke Energy Progress	$ 2,964,399,482	$ 635,040,092	$ 98,705,661	$ 212,714,127	$ 190,427,977	$ 133,192,326	$ 2,329,359,390	$ 115,791,036	$ 460,173,833

Exhibit 3.4.1 Asheville ARO Cash Flows - DEP Response to SCORS 10-08								
Duke Energy Progress								
CCR ARO Project Cost Estimates - Asheville								
As of 9/30/18								
			Actual	Actual	Actual	Actual	Forecast	Forecast
Item	Total	FN	2015	2016	2017	1/1 - 9/30/18	10/1 - 12/31/18	2019
Basin Closure	$ 172,866,832	a	$ -	$ -	$ -	$ -	$ -	$ 56,425,443
CCP Basin Support Projects	10,057,999	b	-	-	-	-	-	5,261,311
EHS	21,550,102	c	-	-	-	-	-	1,424,913
Post-Closure Maintenance	8,522,775	d	-	-	-	-	-	-
Landfill Closure	-	e	-	-	-	-	-	-
Spend To Date	191,934,196		24,187,676	82,788,175	40,931,030	44,027,315	-	-
Remaining Current Year Forecast	22,261,993	f	-	-	-	-	22,261,993	-
Inflation Impacts	24,844,897	g	-	-	-	-	-	1,451,568
Total Asheville	**$ 452,038,793**		**$ 24,187,676**	**$ 82,788,175**	**$ 40,931,030**	**$ 44,027,315**	**$ 22,261,993**	**$ 64,563,236**
FN - Please see Footnotes tab for further explanations								

EXHIBIT DJW - 3.4.1

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 95 of 168

Exhibit 3.4.2 Mayo ARO Cash Flows - DEP Response to SCORS 10-08								
Duke Energy Progress								
CCR ARO Project Cost Estimates - Mayo								
As of 9/30/18								
			Actual	Actual	Actual	Actual	Forecast	Forecast
Item	Total	FN	2015	2016	2017	1/1 - 9/30/18	10/1 - 12/31/18	2019
Basin Closure	$ 75,886,139	a	$ -	$ -	$ -	$ -	$ -	$ 8,020,511
CCP Basin Support Projects	9,438,996	b	-	-	-	-	-	4,594,284
EHS	27,234,666	c	-	-	-	-	-	1,380,911
Post-Closure Maintenance	15,916,872	d	-	-	-	-	-	-
Landfill Closure	6,516,820	e	-	-	-	-	-	-
Spend To Date	25,384,168		7,342,989	7,524,374	5,880,434	4,636,371	-	-
Remaining Current Year Forecast	9,165,451	f	-	-	-	-	9,165,451	-
Inflation Impacts	37,206,475	g	-	-	-	-	-	321,901
Total Mayo	$ 206,749,586		$ 7,342,989	$ 7,524,374	$ 5,880,434	$ 4,636,371	$ 9,165,451	$ 14,317,607
FN - Please see Footnotes tab for further explanations								

EXHIBIT DJW - 3.4.2

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 96 of 168

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 97 of 168

Exhibit 3.4.3 Roxboro ARO Cash Flows - DEP Response to SCORS 10-08								
Duke Energy Progress								
CCR ARO Project Cost Estimates - Roxboro								
As of 9/30/18								
			Actual	Actual	Actual	Actual	Forecast	Forecast
Item	Total	FN	2015	2016	2017	1/1 - 9/30/18	10/1 - 12/31/18	2019
Basin Closure	$ 127,819,202	a	$ -	$ -	$ -	$ -	$ -	$ 4,522,625
CCP Basin Support Projects	12,979,686	b	-	-	-	-	-	9,376,822
EHS	55,431,571	c	-	-	-	-	-	1,956,031
Post-Closure Maintenance	17,774,002	d	-	-	-	-	-	-
Landfill Closure	19,172,064	e	-	-	-	-	-	-
Spend To Date	34,070,691		7,806,769	12,563,556	7,167,110	6,533,256	-	-
Remaining Current Year Forecast	6,366,469	f	-	-	-	-	6,366,469	-
Inflation Impacts	76,189,715	g	-	-	-	-	-	364,676
Total Roxboro	$ 349,803,401		$ 7,806,769	$ 12,563,556	$ 7,167,110	$ 6,533,256	$ 6,366,469	$ 16,220,154
FN - Please see Footnotes tab for further explanations								

Exhibit 3.4.4 Cape Fear ARO Cash Flows - DEP Response to SCORS 10-08								
Duke Energy Progress								
CCR ARO Project Cost Estimates - Cape Fear								
As of 9/30/18								
			Actual	Actual	Actual	Actual	Forecast	Forecast
Item	Total	FN	2015	2016	2017	1/1 - 9/30/18	10/1 - 12/31/18	2019
Basin Closure	$ 369,717,536	a	$ -	$ -	$ -	$ -	$ -	$ 112,162,632
CCP Basin Support Projects	6,233,391	b	-	-	-	-	-	903,363
EHS	12,836,260	c	-	-	-	-	-	1,024,427
Post-Closure Maintenance	9,210,341	d	-	-	-	-	-	-
Landfill Closure	-	e	-	-	-	-	-	-
Spend To Date	33,631,199		7,705,330	8,346,981	6,815,029	10,763,860	-	-
Remaining Current Year Forecast	18,325,181	f	-	-	-	-	18,325,181	-
Inflation Impacts	54,964,581	g	-	-	-	-	-	2,624,080
Total Cape Fear	$ 504,918,488		$ 7,705,330	$ 8,346,981	$ 6,815,029	$ 10,763,860	$ 18,325,181	$ 116,714,502
FN - Please see Footnotes tab for further explanations								

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 98 of 168

Exhibit 3.4.5 HF Lee ARO Cash Flows - DEP Response to SCORS 10-08								
Duke Energy Progress								
CCR ARO Project Cost Estimates - HF Lee								
As of 9/30/18								
			Actual	Actual	Actual	Actual	Forecast	Forecast
Item	Total	FN	2015	2016	2017	1/1 - 9/30/18	10/1 - 12/31/18	2019
Basin Closure	$ 387,784,401	a	$ -	$ -	$ -	$ -	$ -	$ 115,439,726
CCP Basin Support Projects	5,214,096	b	-	-	-	-	-	1,057,904
EHS	19,249,026	c	-	-	-	-	-	1,325,278
Post-Closure Maintenance	10,332,942	d	-	-	-	-	-	-
Landfill Closure	-	e	-	-	-	-	-	-
Spend To Date	54,775,180		7,260,508	13,498,675	13,416,419	20,599,578	-	-
Remaining Current Year Forecast	21,923,632	f	-	-	-	-	21,923,632	-
Inflation Impacts	69,104,642	g	-	-	-	-	-	2,709,927
Total Marshall	$ 568,383,919		$ 7,260,508	$ 13,498,675	$ 13,416,419	$ 20,599,578	$ 21,923,632	$ 120,532,835
FN - Please see Footnotes tab for further explanations								

EXHIBIT DJW - 3.4.5

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 99 of 168

Exhibit 3.4.6 Robinson ARO Cash Flows - DEP Response to SCORS 10-08								
Duke Energy Progress								
CCR ARO Project Cost Estimates - Robinson								
As of 9/30/18								
			Actual	Actual	Actual	Actual	Forecast	Forecast
Item	Total	FN	2015	2016	2017	1/1 - 9/30/18	10/1 - 12/31/18	2019
Basin Closure	$ 123,149,703	a	$ -	$ -	$ -	$ -	-	$ 32,817,857
CCP Basin Support Projects	166,265	b	-	-	-	-	-	50,053
EHS	12,194,921	c	-	-	-	-	-	557,952
Post-Closure Maintenance	3,764,217	d	-	-	-	-	-	-
Landfill Closure	-	e	-	-	-	-	-	-
Spend To Date	11,431,675		2,581,604	3,834,014	2,090,145	2,925,911	-	-
Remaining Current Year Forecast	10,866,681	f	-	-	-	-	10,866,681	-
Inflation Impacts	17,988,315	g	-	-	-	-	-	768,795
Total Robinson	**$ 179,561,777**		**$ 2,581,604**	**$ 3,834,014**	**$ 2,090,145**	**$ 2,925,911**	**$ 10,866,681**	**$ 34,194,657**
FN - Please see Footnotes tab for further explanations								

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 101 of 168

Exhibit 3.4.7 Sutton ARO Cash Flows - DEP Response to SCORS 10-08								
Duke Energy Progress								
CCR ARO Project Cost Estimates - Sutton								
As of 9/30/18								
			Actual	Actual	Actual	Actual	Forecast	Forecast
Item	Total	FN	2015	2016	2017	1/1 - 9/30/18	10/1 - 12/31/18	2019
Basin Closure	$ 151,788,408	a	$ -	$ -	$ -	$ -	$ -	$ 69,901,593
CCP Basin Support Projects	4,818,558	b	-	-	-	-	-	2,813,396
EHS	25,360,989	c	-	-	-	-	-	1,317,607
Post-Closure Maintenance	11,299,529	d	-	-	-	-	-	-
Landfill Closure	-	e	-	-	-	-	-	-
Spend To Date	255,525,554		37,189,549	79,669,346	104,689,533	33,977,126	-	-
Remaining Current Year Forecast	19,844,924	f	-	-	-	-	19,844,924	-
Inflation Impacts	24,581,210	g	-	-	-	-	-	1,702,750
Total Sutton	$ 493,219,171		$ 37,189,549	$ 79,669,346	$ 104,689,533	$ 33,977,126	$ 19,844,924	$ 75,735,346
FN - Please see Footnotes tab for further explanations								

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 102 of 168

Exhibit 3.4.8 Weatherspoon Cash Flows - DEP Response to SCORS 10-08								
Duke Energy Progress								
CCR ARO Project Cost Estimates - Weatherspoon								
As of 9/30/18								
			Actual	Actual	Actual	Actual	Forecast	Forecast
Item	Total	FN	2015	2016	2017	1/1 - 9/30/18	10/1 - 12/31/18	2019
Basin Closure	$ 112,823,615	a	$ -	$ -	$ -	$ -	$ -	$ 16,039,468
CCP Basin Support Projects	4,009,116	b	-	-	-	-	-	409,708
EHS	16,211,492	c	-	-	-	-	-	1,043,977
Post-Closure Maintenance	10,183,220	d	-	-	-	-	-	-
Landfill Closure	-	e	-	-	-	-	-	-
Spend To Date	28,287,429		4,631,236	4,489,006	9,438,277	9,728,910	-	-
Remaining Current Year Forecast	7,036,705	f	-	-	-	-	7,036,705	-
Inflation Impacts	31,172,769	g	-	-	-	-	-	402,343
Total Weatherspoon	**$ 209,724,346**		**$ 4,631,236**	**$ 4,489,006**	**$ 9,438,277**	**$ 9,728,910**	**$ 7,036,705**	**$ 17,895,496**
FN - Please see Footnotes tab for further explanations								

Duke Energy Progress, LLC
Docket No. 2018 – 318 – E
Amortize deferred environmental costs
For the test period ended December 31, 2017

SC-1802
Page 1 of 1

Line No.	Description	Coal Ash ARO System Spend (a) System Spend excl CAMA	(b) CAMA Only Costs	(c) % to SC for Spend Note 3	Duke Energy Progress ARO Coal Ash Deferral (South Carolina Retail) (d)=(i) Prior Mth + (l) Prior Month Beginning Balance	(e)=(a)x (c) SC Spend excludes CAMA	(f) NDTF Overcollections	(g) Active Plant COR Offset Note 1,4	(h) Retired Coal Ash Plant COR Offset Note 2,4	(i)=sum of (d) thru (h) SC Balance for Return	(j) = (i) x cost of debt Compounded monthly Deferred Cost of Debt Note 5	(k) = (i) x cost of equity Deferred Cost of Equity Note 5	(l)=(j)+(k) Total Return	(m)=(i)+ total to date col (l) Ending Balance
1														
2	Jul-16	$ 22,904,533	$ -	9.704%	$ -	2,222,858	(387,621)			1,835,035	1,749	8,186	9,934	1,844,969
3	Aug	21,669,364	-	9.704%	1,844,969	2,102,795	(387,621)			3,560,143	3,393	15,881	19,274	3,579,417
4	Sept	17,200,184	-	9.704%	3,579,417	1,669,106	(387,621)	(94,034)	(296,518)	4,470,348	4,260	19,941	24,201	4,494,550
5	Oct	14,823,333	7,583	9.704%	4,494,550	1,438,458	(387,621)			5,545,385	5,284	24,737	30,021	5,575,406
6	Nov	14,821,727	38,509	9.704%	5,575,406	1,438,300	(387,621)			6,626,085	6,314	29,558	35,872	6,661,957
7	Dec	19,071,049	25,869	9.704%	6,661,957	1,850,655	(387,621)	(94,034)	(296,518)	7,734,438	7,370	34,502	41,872	7,776,310
8	Jan-17	11,366,877	12,213	9.710%	7,776,310	1,103,724	-			8,880,034	8,462	39,612	48,074	8,928,108
9	Feb	18,212,544	43,020	9.710%	8,928,108	1,768,438	-			10,696,546	10,193	47,716	57,908	10,754,455
10	March	16,016,207	79,691	9.710%	10,754,455	1,555,174	-	(94,034)	(296,518)	11,919,076	11,358	53,169	64,527	11,983,603
11	April	16,335,977	58,443	9.710%	11,983,603	1,586,223	-			13,569,826	12,931	60,533	73,464	13,643,290
12	May	21,029,645	71,401	9.710%	13,643,290	2,041,979	-			15,685,268	14,947	69,969	84,916	15,770,184
13	June	17,563,524	46,178	9.710%	15,770,184	1,705,418	-	(94,034)	(296,518)	17,085,050	16,281	76,214	92,494	17,177,544
14	July	14,933,603	72,122	9.710%	17,177,544	1,450,072	-			18,627,616	17,751	83,095	100,845	18,728,461
15	Aug	17,384,726	67,508	9.710%	18,728,461	1,688,057	-			20,416,518	19,455	91,075	110,530	20,527,048
16	Sept	14,249,151	127,106	9.710%	20,527,048	1,383,593	-	(94,034)	(296,518)	21,520,088	20,507	95,998	116,504	21,636,592
17	Oct	14,555,146	61,009	9.710%	21,636,592	1,413,305	-			23,049,897	21,965	102,822	124,786	23,174,683
18	Nov	10,899,356	26,442	9.710%	23,174,683	1,058,327	-			24,233,011	23,092	108,099	131,191	24,364,202
19	Dec	17,101,938	112,710	9.710%	24,364,202	1,660,598	-	(94,781)	(298,701)	25,631,339	24,425	114,337	138,762	25,770,100
20	Jan-18	12,090,888	200,173	9.548%	25,770,100	1,154,430	-			26,924,530	31,183	120,106	151,289	27,075,819
21	Feb	14,582,754	189,697	9.548%	27,075,819	1,392,351	-			28,468,170	32,971	126,992	159,963	28,628,133
22	March	16,964,328	(45,075)	9.548%	28,628,133	1,619,742	-	(94,003)	(296,418)	29,857,455	34,580	133,189	167,769	30,025,224
23	April	13,253,460	246,358	9.548%	30,025,224	1,265,431	-			31,290,655	36,240	139,582	175,822	31,466,477
24	May	14,848,913	2,373,477	9.548%	31,466,477	1,417,764	-			32,884,241	38,085	146,691	184,777	33,069,018
25	June	15,579,605	(1,477,230)	9.548%	33,069,018	1,487,530	-			34,556,548	40,022	154,151	194,173	34,750,721
26	July	10,427,877	166,788	9.548%	34,750,721	995,646	-			35,746,367	41,400	159,458	200,859	35,947,226
27	Aug	18,953,966	308,834	9.548%	35,947,226	1,809,712	-			37,756,938	43,729	168,427	212,156	37,969,094
28	Sept	14,148,093	377,619	9.548%	37,969,094	1,350,850	-			39,319,944	45,539	175,400	220,939	39,540,883
29	Oct	31,804,327	-	9.548%	39,540,883	3,036,655	-			42,577,538	49,312	189,931	239,243	42,816,781
30	Nov	31,804,327	-	9.548%	42,816,781	3,036,655	-			45,853,436	53,105	204,545	257,650	46,111,087
31	Dec	31,804,327	-	9.548%	46,111,087	3,036,655	-			49,147,742	56,921	219,240	276,161	49,423,903
32	Jan-19			9.548%	49,423,903	-	-			49,423,903	57,241	220,472	277,713	49,701,616
33	Feb			9.548%	49,701,616	-	-			49,701,616	57,583	221,711	279,273	49,980,889
34	March			9.548%	49,980,889	-	-			49,980,889	57,886	222,956	280,843	50,261,732
35	April			9.548%	50,261,732	-	-			50,261,732	58,211	224,209	282,421	50,544,153
36	May			9.548%	50,544,153	-	-			50,544,153	58,539	225,469	284,008	50,828,160 [Note 6]
37														
38														
39		526,401,949	3,192,445			50,740,298	(2,325,728)	(658,936)	(2,077,710)		1,022,263	4,127,973	5,150,236	
40														

Asheville Prudence Disallowance (1,516,933)
Balance for Amortization 49,311,227

Note 1: Active Plant COR is used to offset the ARO for purposes of calculating a return - amounts per books through Mar 15 2018
Note 2: Retired Plant COR is used to offset the ARO for purposes of calculating a return - amounts per books through Mar 15 2018
Note 3: DPALL Production Demand allocation factors
Note 4: SC-1804 Cost of Removal annual estimates/4 for quarterly bookings; COR is part of the new depreciation study effective 3/15/2018
Note 5: Cost of debt and equity for each year of the deferral is represented on SC 1804
Note 6: Assumes Rates effective date of 6/1/2019
Note 7: The 2016 SC Rate case included coal ash spend through June, 2016.

EXHIBIT DJW - 3.5.0

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 103 of 168

Duke Energy Progress, LLC
Docket No. 2018 – 318 – E
Amortize deferred environmental costs
For the test period ended December 31, 2017

		Coal Ash Non ARO System													
		(a)	(b)	(c)	(d)=(a)x (c)	(e)=(b)x (c) / 2	(f) = YTD (k)	(g)=sum of (d) thru (f)	(h) = (g) x cost of debt	(i) = (g) x cost of equity	(j)=(h)+(i)	(k)	(l)=(j)+(k) x cost of capital/2	(m)=(j) + (k) + (l)
Line No.	Description	System Plant Balance Note 1	Plant Adds Note 2	% to SC for Spend Note 3	SC Plant Balance	SC Plant Adds Note 4	Accumulated Depreciation	SC Rate Base for Return	Deferred Cost of Debt Note 5	Compounded monthly Deferred Cost of Equity Note 5	Total Cost of Capital Note 6	Deferred Depreciation	After tax return on Deferred Expenses Mid-Month convention	Ending Balance
1														
2	Jan-18	$ -	$ 39,059	9.548%	$ -	1,865	-	$ 1,864.65	$ 2.9	$ 11.1	$ 14.0	$ -	$ 0.0	$ 14.0
3	Feb	39,059	3,766	9.548%	3,729	180	(9)	3,900.27	6	23	29.20	8	0.19	52.21
4	March	42,825	170	9.548%	4,089	8	(21)	4,076.46	6	24	30.52	12	0.41	94.84
5	April	42,995	9,154	9.548%	4,105	437	(35)	4,507.12	7	27	33.74	14	0.67	143.71
6	May	52,149	5,917,390	9.548%	4,979	282,493	(51)	287,421.85	444	1,706	2,151.92	16	6.90	2,318.07
7	June	5,969,539	84,954	9.548%	569,966	4,058	(3,155)	570,868.87	881	3,393	4,274.07	3,104	33.75	9,730.00
8	July	6,054,493	54,017	9.548%	578,077	2,579	(6,303)	574,352.69	888	3,414	4,300.17	3,148	75.60	17,254.18
9	Aug	6,108,511	100,202	9.548%	583,234	4,764	(9,477)	578,540.69	893	3,439	4,331.52	3,174	116.04	24,878.09
10	Sept	6,208,713	70,890	9.548%	592,802	3,384	(12,704)	583,482	900	3,468	4,369	3,227	161.13	32,634.35
11	Oct	6,279,603	5,781,000	9.548%	599,570	275,982	(14,608)	860,945	1,329	5,117	6,446	1,904	206.83	41,190.89
12	Nov	12,060,603	61,424,201	9.548%	1,151,534	3,887,151	(18,264)	5,020,421	7,747	29,840	37,586	3,656	347.33	82,781.94
13	Dec	93,484,804	78,181,474	9.548%	8,925,836	3,732,344	(45,603)	12,611,577	19,462	74,961	94,423	28,340	810.05	206,354.17
14	Jan-19	171,666,277		9.548%	16,390,524	-	(98,643)	16,291,881	25,141	96,836	121,977	52,040	1,645.40	382,019.51
15	Feb	171,666,277		9.548%	16,390,524	-	(150,683)	16,239,841	25,061	96,527	121,587	52,040	2,634.37	556,281.20
16	March	171,666,277		9.548%	16,390,524	-	(202,723)	16,187,801	24,980	96,217	121,198	52,040	3,623.89	735,142.58
17	April	171,666,277		9.548%	16,390,524	-	(254,763)	16,135,762	24,900	95,908	120,808	52,040	4,616.38	912,607.03
18	May	171,666,277		9.548%	16,390,524	-	(306,803)	16,083,722	24,820	95,599	120,419	52,040	5,612.46	1,090,677.94
19														
20		$ 994,674,677	##########		$ 94,970,543	$ 8,195,262	$ (1,124,844)		$ 157,466	$ 606,513	$ 763,979	$ 306,803	$ 19,896	

Steam Production composite depreciation rate 3.81%
Source: SC-1002 - Steam Production plant col 3
Used for forecasted months depreciation expense

Note 1: Beginning balance Provided by Asset Accounting
Note 2: Actual through June provided by Asset Accounting; forecast provided by Forecasting group
Note 3: DPALL Production Demand allocation factors
Note 4: Assumes mid month convention on plant adds
Note 5: Cost of debt and equity for each year of the deferral is represented on SC 1804
Note 6: Total cost of capital after tax from SC 1804
Note 7: Assumes Rates effective date of 6/1/2018

EXHIBIT DJW - 3.5.1

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 104 of 168

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 105 of 168

Duke Energy Progress, LLC
Docket No. 2018 – 318 – E
Amortize deferred environmental costs
For the test period ended December 31, 2017

SC-1804
Page 1 of 1

Cost of debt and Equity for coal ash deferral periods

July 2016 - Dec 2016

	Ratio	APPROVED COST RATE	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	1	2	3=1*2	4		
LONG TERM DEBT	47.00%	3.94%	1.8518%	1.1435%	1.8518%	
EQUITY	53.00%	10.10%	5.3530%	5.3530%	8.6700%	6=4/(1-5)
TOTAL	100.00%		7.2048%	6.4965%	10.5218%	
Return on Equity		2.557%				
Effective State and Federal Income Tax Rate		38.25%	5			

Jan-Dec 2017

	Ratio	APPROVED COST RATE	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	1	2	3=1*2	4		
LONG TERM DEBT	47.00%	3.94%	1.8518%	1.1435%	1.8518%	
EQUITY	53.00%	10.10%	5.3530%	5.3530%	8.6700%	6=4/(1-5)
TOTAL	100.00%		7.2048%	6.4965%	10.5218%	
Return on Equity		2.557%				
Effective State and Federal Income Tax Rate		38.25%	5			

Jan-Dec 2018

	Ratio	APPROVED COST RATE	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	1	2	3=1*2	4		
LONG TERM DEBT	47.00%	3.94%	1.8518%	1.3898%	1.8518%	
EQUITY	53.00%	10.10%	5.3530%	5.3530%	7.1326%	6=4/(1-5)
TOTAL	100.00%		7.2048%	6.7428%	8.9844%	
Return on Equity		2.803%				
Effective State and Federal Income Tax Rate		24.95%	5			

Duke Energy Progress, LLC
Docket No. 2018 – 318 – E
Amortize deferred environmental costs
For the test period ended December 31, 2017
(Dollars in thousands)

SC-1805
Page 1 of 1

Estimate of Cost of Removal for Closure of Ash Ponds

Line		Decommissioning Amount for Closure of Ash Ponds (1)						[3] 74.371%		9.917%
1		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = 74.371% x (d) / (g)	(i)=9.9169% x (d)/(g)
2	Plant	Closure of Ash Ponds (2)	Project Indirects Adder (5%) (2)	Contingency (10%) (2)	Total	Estimated Retirement Date per Depr Study	Depr Study Implementation Date	Retail Recovery Period/Remaining Life per Depr Study (in years)	Annual Retail COR for Ash Pond Closure	SC Annual Retail COR
3										
4	Cape Fear	$ 22,000	$ 1,100	$ 2,200	$ 25,300		July 1, 2012	10	$ 1,882	251
5	Lee	43,000	2,150	4,300	49,450		July 1, 2012	10	$ 3,678	490
6	Robinson	11,000	550	1,100	12,650		July 1, 2012	10	$ 941	125
7	Sutton	21,000	1,050	2,100	24,150		July 1, 2012	10	$ 1,796	239
8	Weatherspoon	7,000	350	700	8,050		July 1, 2012	10	$ 599	80
9	Subtotal Early-Retired Plants	104,000	5,200	10,400	119,600				$ 8,895	1,186
10	Asheville	9,000	450	900	10,350	2033	July 1, 2012	21	$ 367	49
11	Mayo	19,000	950	1,900	21,850	2035	July 1, 2012	23	$ 707	94
12	Roxboro	47,000	2,350	4,700	54,050	2035	July 1, 2012	23	$ 1,748	233
13	Subtotal active plants	75,000	3,750	7,500	86,250				$ 2,821	376
14	Total	$ 179,000	$ 8,950	$ 17,900	$ 205,850				$ 11,716	1,562
15										
16										
17										
18	Notes									
19	(1) Amounts reflect 100% system amounts.									
20	(2) Amounts per DEP Dismantlement Study									
21	(3) Based on allocation factors from the last approved NC rate case									

1340

EXHIBIT DJW - 3.5.3

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 106 of 168

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 107 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 1 of 44

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2018-318-E

In the Matter of :		
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
For Adjustments in Electric Rate Schedules and	)	**DR. JULIUS A. WRIGHT**
Tariffs	)	**FOR DUKE ENERGY**
	)	**PROGRESS, LLC**

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 108 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 2 of 44

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, OCCUPATION, TITLE AND BUSINESS ADDRESS.

A. Julius A. Wright, Managing Partner, J. A. Wright & Associates, LLC, 18 Edgewater Drive, Cartersville GA, 30121. I am a consultant to regulated utilities and regulatory agencies and other public bodies on issues related to economics, economic modeling, regulatory policy, industry restructuring, demand-side investments, and resource planning.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this testimony on behalf of Duke Energy Progress, LLC ("DE Progress," or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received an undergraduate degree from Valdosta State College (BS Chemistry), an MBA in Finance from Georgia State University, and a Master's and Ph.D. in Economics from North Carolina State University, where I focused on regulatory and environmental economics. Among other past experiences, I served as a Commissioner on the North Carolina Utilities Commission ("NCUC" or the "Commission") from 1985 to 1993. Prior to serving as a member of the Commission, I served three terms as a North Carolina State Senator and worked in process engineering for 12 years at three chemical plants, the last with Corning in Wilmington, NC.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 109 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 3 of 44

Over the past 25 plus years in my consulting practice, I have dealt extensively with electric and natural gas utilities focusing on a number of issues. In this context, I have testified before regulatory commissions and legislative bodies, presented studies and authored reports on issues related to electric and gas regulation, and I have been a guest speaker at the Bonbright Conference, other seminars, and at the Georgia Institute of Technology. I have been a visiting professor teaching both microeconomics and macroeconomics courses at the University of The Virgin Islands. I was also one of three economists engaged by the California State Auditor to examine the problems that led to that state's electric energy crisis in the summer and fall of 2000. I have worked for the last 20 plus years in the field of electric and gas regulation, primarily in the Southeast. A copy of my resume is attached as Wright Exhibit 1.

Q. PLEASE DISCUSS THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my direct testimony is to support DE Progress' request to recover costs incurred for coal ash disposal in response to new, more stringent environmental regulations.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In the next section of my testimony, I provide a discussion of the general regulatory principles dealing with the recovery of environmental costs incurred by electric utilities in South Carolina. In Section III, I provide a brief historical review of coal ash disposal regulations, how these regulations have evolved over time, and how these evolving regulations have impacted the

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 110 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 4 of 44

Company. I conclude in Section IV by discussing why I believe DE Progress' proposed coal ash related expenses in this filing should be recoverable as recommended in the application and Company witnesses' testimony.

II. BACKGROUND: RECOVERY OF ENVIRONMENTAL COSTS

Q. WHAT ARE RECOVERABLE COSTS AS THEY RELATE TO ELECTRIC UTILITY EXPENDITURES IN SOUTH CAROLINA?

A. Recoverable costs include costs that are just and reasonable and used and useful in the provision of adequate, safe, reliable, and reasonable electric service to a utility's customers. Specifically, South Carolina Code of Laws at § 58-27-810 declares the "rates shall be just and reasonable," and this standard is repeated in § 58-27-850. With respect to the "used and useful" standard, like other states South Carolina has defined used and useful utility property as "property which it [the utility] necessarily devotes to rendering the regulated services" and has allowed recovery for such property in rates. *Hamm v. S.C. Pub. Serv. Comm'n*, 309 S.C. 282, 286 n. 1, 422 S.E.2d 110, 112 n. 1 (1992) (quoting *Southern Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n of S.C.*, 270 S.C. 590, at 600, 244 S.E.2d 278, at 283 (1978)).

The "used and useful" definition as it relates to rate base in South Carolina was clarified in a Commission Order that stated "The rate base is comprised of the value of the Company's property used and useful in providing retail electric service to the public..." Order 87-1381, December 30, 1987, page 15.

With respect to the how retail electric service must be provided to

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 111 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 5 of 44

South Carolina ratepayers, the Commisison's Code of Regulations Section 103-301(2) states the purpose of the Code of Regulations is to *"to define good practice...intended to insure adequate and reasonable service."* All of these policies, along with safety and reliability, are further embodied in the Code of Regulations in Sections 103-360 which states *"[t]he electric plant of an electrical utility shall be constructed, installed, maintained and operated in accordance with good engineering practice to assure, as far as reasonably possible, continuity of service, uniformity in the quality of service, and the safety of persons and property."*

As I discuss further herein, because environmental compliance costs are a necessary used and useful cost of providing safe, reliable and adequate electric service, then it follows that these types of costs – and a return on those costs – are recoverable in rates.

Q. ARE ENVIRONMENTAL COMPLIANCE COSTS A NECESSARY EXPENDITURE SIMILAR TO OTHER COSTS A UTILITY MIGHT SPEND IN PRODUCING AND DELIVERING POWER?

A. Yes. In order to comply with environmental regulations the Company incurs costs and these are similar to other costs necessary for the generation of electric power. Thus as part of the operating expenses related to coal-fired generating facilities, coal combustion residuals ("CCR") is produced in the coal combustion process, and this ash has been collected in compliance with environmental regulations at the time. These environmental expenses include costs like scrubbers or coal ash facilities which can be rate base type expenses

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 112 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 6 of 44

whose costs would be recovered over time. In addition, environmental costs related to the treatment of pollutants, like ammonia and lime, or the cost of emission allowance for SO2, NOx, mercury, and particulates, are all variable environmental costs and are generally recoverable through the fuel adjustment rider in South Carolina (§ 58-27-865). All of these environmental costs are necessary for producing electricity in compliance with environmental standards and, like nuclear decommissioning costs or coal plant retirement costs, based on my experience and knowledge of fuel adjustment cost recovery mechanisms in many states, these types of costs have long been deemed recoverable from a utilities' ratepayers, including DE Progress in South Carolina.

It should also be recognized that the coal plants associated with these costs have been used and useful in providing low-cost, reliable power to South Carolina customers for more than a century, and that is true regardless of whether the generating plant is located in South Carolina or North Carolina – all of the Company's generating units provide service on a systemwide basis to both states. Consequently, these types of costs and, if any amount is deferred over time, a return would be appropriately recoverable in rates to ensure that the Company received the equivalent of the full amount of those costs.

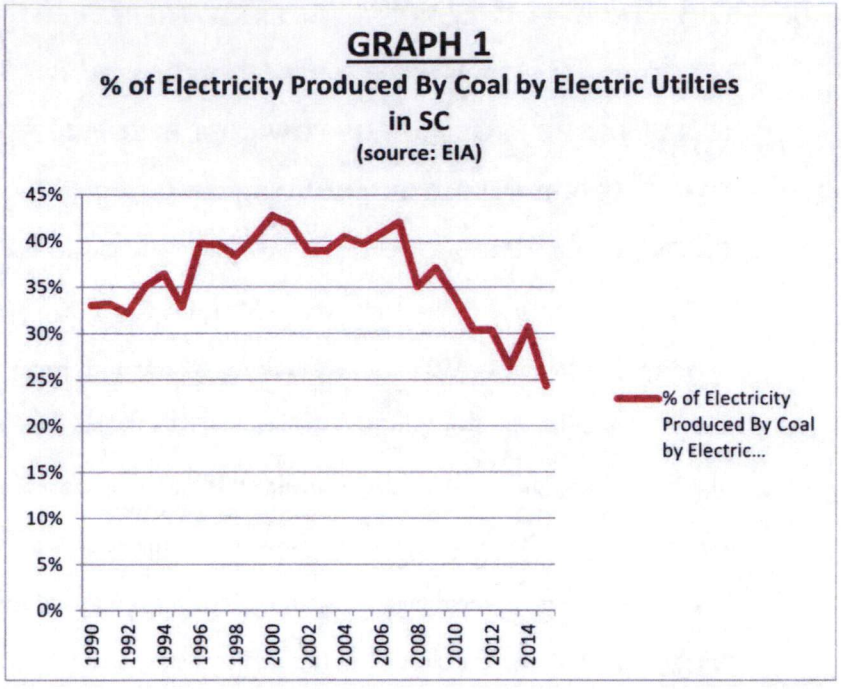
ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 113 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 7 of 44

Q. WHY HAVE YOU CONCLUDED THAT THESE COAL-FIRED ELECTRIC GENERATING PLANTS HAVE BEEN USED AND USEFUL IN THE PROVISION OF LOW-COST ELECTRIC SERVICE TO CUSTOMERS IN SOUTH CAROLINA.

A. The Company's electric power generation from burning coal dates back to the 1920's. For example, the Cape Fear Plant in Moncure, North Carolina, began commercial operation in 1923 with an ultimate generating capacity of 316 MW. Because power generation facilities are generally operated on a lowest cost facility being used first, one can conclude that the Company's coal plants have been used and useful in providing low-cost, reliable power to South Carolina customers for more than a century. This conclusion is illustrated in Graph 1 that illustrates that since 1990 (the earliest data available for the EIA) usually more than 30% of the South Carolina's electric generation was provided by coal-fired generation.[1] While more recently this dependence on coal has diminished because of new environmental standards, coal-fired generation continues to be an important component of DE Progress' generation in South Carolina.

[1] This was the latest statewide data available from the EIA when the first draft of this testimony was developed. See State Historical Tables for 2015 (October 2016 as revised November 2016) (https://www.eia.gov/electricity/data/state/).

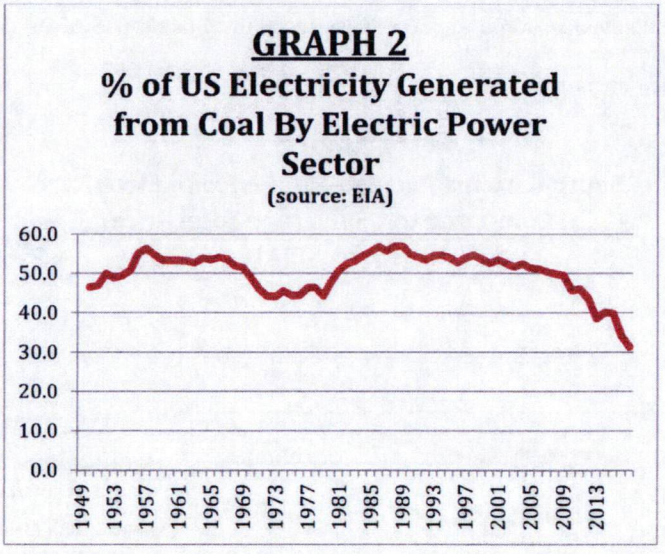
ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 114 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 8 of 44



For a more historic perspective on the importance of coal to the nation's electric industry, Graph 2 indicates that for the past seven decades coal has provided the fuel to produce about 50% of the nation's electric energy.[2] It should be noted that coal was chosen as a fuel source, both in South Carolina and nationwide, primarily on the basis of economics, meaning that at the time it was the least costly, reliable option to use as a generation fuel resource. Because of this economic fact, but for the use of coal-fired generation, historical electric prices in the State and nationwide would have been higher.

[2] This was the latest nationwide data available from the EIA. See April 2017 Monthly Energy Review, Table 7.2b Electricity Net Generation: Electric Power Sector (April 25, 2017) (https://www.eia.gov/totalenergy/data/monthly/archive/00351704.pdf).

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 115 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 9 of 44



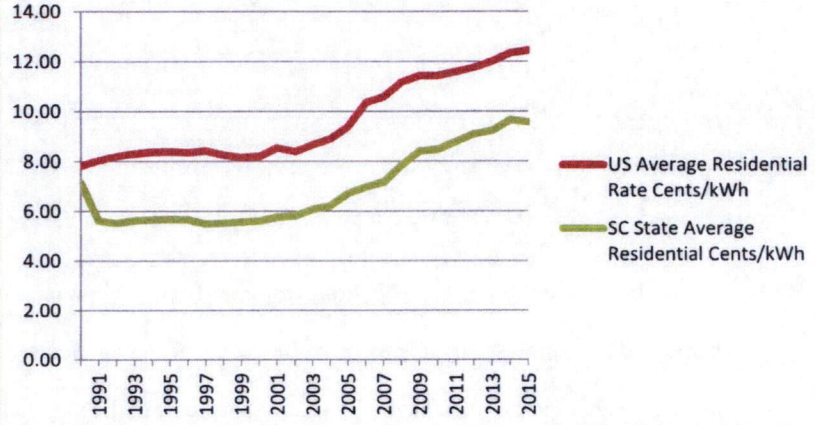
In addition, the use of DE Progress' coal-fired generation has directly benefitted the State's customers by virtue of the fact that South Carolina's average retail electric rates have historically been below the national average. This is shown in Graph 3 which provides a historical comparison of the State's average electric price to the nation's. As this Graph 3 indicates, the State's average electric prices have been below the national average since at least 1990, which is the first year this state level data was available at the EIA. These below national average electric rates have been an economic benefit to South Carolina and its electric consumers.[3] Because electric rates are determined by the underlying cost to produce the electricity, and recognizing that coal-fired plants were chosen and are dispatched primarily for economic reasons, this simply means that the State's "below average" electric rates have

[3] This was the latest statewide data available from the EIA. See https://www.eia.gov/totalenergy/data/annual/showtext.php?t=ptb0810.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 116 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 10 of 44

been achieved in large measure because of the State's use of its coal-fired electric generation.

GRAPH 3
South Carolina Average Total Price of Electricity Compared to US Average Total Price (source: EIA)



Q. HAS THIS COMMISSION ALLOWED THE RECOVERY OF COSTS RELATED TO ENVIRONMENTAL EXPENDITURES?

A. Yes. I have already discussed how some environmental costs in South Carolina, such as ammonia, lime and other reagents, are recovered through the fuel adjustment rider (§ 58-27-865). Importantly, the recovery of other environmental costs, such as scrubbers or ash basins, related to environmental compliance would be consistent with the public policy of the South Carolina which states it is "the public policy of the State to maintain reasonable standards of purity of the air and water resources of the State, consistent with the public health, safety and welfare of its citizens, maximum employment,

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 117 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 11 of 44

the industrial development of the State..." (at § 48-1-20).

Consequently, in order to comply with both the State's public policy goals and remain compliant with environmental standards, the Company has made numerous investments over time in compliance with historical coal ash and other environmental regulations, as discussed at length in the direct testimony of Company Witness Kerin. It is my experience that these types of costs, including the reasonable costs associated with operating, maintaining and upgrading environmental equipment, plus a return, have been routinely recovered as a cost of service through general rate cases, whether as capital or ongoing operation and maintenance expense or some combination thereof.

In summary, when a utility invests in scrubbers to meet new and heightened environmental standards, these costs have routinely been recoverable. Similarly, when a utility invests dollars to meet new environmental coal ash remediation standards, these costs should likewise be recoverable. For example, in South Carolina the deferral balance of costs associated with a Cliffside Unit 5 scrubber were amortized and in the rate base (Settlement Agreement, Nov. 30, 2011, Docket No. 2011-271-E, Attachment A, page 2). In addition, in Docket No. 2009-226-E costs associated with scrubbers at the Allen Steam Station were amortized and in rate base (Settlement Agreement, Nov. 24, 2009, Docket No. 2009-226-E, Attachment A, page 2).

Where state specific requirements are indicated, those costs are often shared between the two states consistent with the manner in which electrons

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 118 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 12 of 44

flow. In other words, shared costs for facilities that generate or have generated electricity to both North and South Carolina are allocated between the two states.

Q. HAS THIS COMMISSION ADDRESSED THE RECOVERY OF NEW COSTS ASSOCIATED WITH COAL ASH DISPOSAL ?

A. Yes. In Docket No. 2016-227-E, DE Progress was allowed to recover coal ash expense amortized over fifteen (15) years plus the Order's approved return, albeit the Order did state that this finding had no precedential effect and will not prejudice the position of any Party in any future proceeding before the Commission.[4] In this case, the Company is asking to be allowed to recover coal ash expenses amortized over five years.

Q. HOW ARE COSTS RECOVERED WHEN THE COSTS RELATE TO FACILITIES IN TWO DIFFERENT STATES, LIKE WITH THE ELECTRIC SYSTEM IN NORTH CAROLINA AND SOUTH CAROLINA?

A. Under this scenario, cost recovery depends on the type of cost. Some state specific costs, unless directly assigned, are shared, or allocated, between both states. In other words, shared costs for facilities that generate or have generated electricity to both North and South Carolina are usually allocated between the two states. These type of costs include a variety of things such as workers compensation type costs, differences in everyday operating costs like employees expenses, contractor expenses, fuel costs, and even costs like fuel

[4] Order in Docket No. 2016-227-E, Dec. 21, 2016, page 11, paragraph 15.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 119 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 13 of 44

transportation which can be different depending on the location of a generating station (for example, rail service from coal mines to North Carolina can be different, and usually cheaper because of distance, then rail service to South Carolina). In addition, property taxes in South Carolina are higher than property taxes in North Carolina, however these taxes for system assets like generation plants are allocated to the whole system and not recovered on a state specific basis.

Q. HAVE NORTH CAROLINA AND SOUTH CAROLINA SHARED ENVIRONMENTAL EXPENSES PRIOR TO THIS CASE?

A. Yes. For example, the Cliffside and Allen generating stations scrubbers mentioned above have been costs shared between the two states. This cost sharing is common where a utility's operations span multiple states and the utility property used to provide one particular state's electric service may be located in another state. Also, the Company has entered into a Consent Agreement with the South Carolina Department of Health and Environmental Control (and a related Settlement Agreement with several environmental groups) dealing with coal ash at the Robinson Plant, and the costs associated with these South Carolina agreements are shared with North Carolina ratepayers. Additional examples of states sharing environmental costs would be the Southern Company utilities in Georgia, Albama, Mississippi, and Florida, and Entergy with electric utility services in Mississippi, Arkansas, Louisiana, and Texas. In addition, coal ash disposal costs and beneficial reuse revenues have to date been allocated and shared between both states.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 120 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 14 of 44

III. A BRIEF REVIEW OF THE HISTORY OF COAL ASH DISPOSAL STANDARDS

Q. PLEASE DISCUSS SOME OF THE INITIAL COAL ASH DISPOSAL STANDARDS.

A. The Company's electric power generation from burning coal dates back to the 1920's. All of the Company's coal plants produced CCRs as fly ash and bottom ash as direct by-products of the coal combustion process. In the 1950's the electric utility industry began to transport bottom ash by water sluicing to constructed surface impoundments, which we commonly refer to as ash basins. Over time, as discussed in more detail in the direct testimony of Company Witness Kerin, the Company has consistently followed industry standard practices in compliance with coal ash regulation.

Q. DID THE COMMISSION ALLOW THE STATE'S ELECTRIC UTILITIES TO RECOVER THE COSTS ASSOCIATED WITH THESE EARLIER COAL ASH DISPOSAL REGULATIONS?

A. Yes. As I mentioned earlier, these types of expenses have been routinely recovered as a cost of service and included in rate cases including the reasonable costs associated with operating, maintaining and upgrading environmental equipment. The cost recovery for these rate-based environmental costs also usually included a return. Also, as I mentioned earlier, in Docket No. 2016-227-E, the Commission allowed DE Progress to recover coal ash expense amortized over fifteen (15) years plus the Order's

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 121 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 15 of 44

approved return.[5]

Q. HOW HAVE THE COAL ASH DISPOSAL STANDARDS CHANGED OVER THE PAST DECADE?

A. Coal ash use and disposal has been studied by the Environmental Protection Agency ("EPA") since the mid-1980s. After several studies and some limited regulatory standards, on May 22, 2000, the Environmental Protection Agency ("EPA") determined the need to regulate coal combustion wastes that are disposed in landfills and surface impoundments under Subtitle D (applicable to non-hazardous waste) of the Resource Conservation and Recovery Act.

On December 22, 2008, a dike at a surface impoundment at Tennessee Valley Authority's ("TVA") Kingston Fossil Plant in Harriman, Tennessee, failed. In part as a response to this TVA accident, on June 21, 2010, the EPA published in the Federal Register proposed new coal ash disposal regulations for CCRs.[6] The proposed regulations specifically referenced the TVA incident as a major reason for the proposed rule.[7] The EPA's proposed coal ash disposal rule also discussed several other coal ash incidents that led to the promulgation of the rule:

> *"at the time of the May 2000 Regulatory Determination, the Agency was aware of 14 cases of proven damages and 36 cases of potential damages resulting from the disposal of CCRs. The Agency has since learned of an additional 13 cases of proven damages and 4 cases of potential damages, including a catastrophic release of CCRs from a disposal unit at the Tennessee Valley Authority (TVA) Kingston facility in Harriman, Tennessee in December 2008. In total, EPA has documented 27 cases of proven damages and 40 cases of*

[5] Order in Docket No. 2016-227-E, Dec. 21, 2016, page 11, paragraph 15.
[6] Federal Register/Vol. 75, No. 118/Monday, June 21, 2010/Proposed Rules, page 35128.
[7] IBID, page 35132.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 122 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 16 of 44

potential damages resulting from the disposal of CCRs. Proven damage cases have been documented in 12 states, and potential damage cases—in 17 states."[8]

A more thorough discussion of these newer coal ash disposal regulations is contained in the testimony of Company Witness Kerin.

Q. DID THE ACCIDENTAL COAL ASH SPILL AT THE DUKE ENERGY CAROLINAS' DAN RIVER FACILITY IMPACT THE FINAL CCR RULE?

A. No. First, it is important to note that the EPA's proposed rule's publication date precedes the February 2, 2014 coal ash release accident at the Dan River Steam Station ("Dan River"), the Dan River accident was not mentioned in the EPA's proposed rule, nor could it have been, as a reason for establishing the rule. Later, the finalized EPA rule, signed on December 19, 2014 and published in the *Federal Register* (FR) on April 17, 2015 (the "CCR Rule"),[9] did reference the Dan River accident, but it did not indicate that the accident modified the proposed rule. Second, in promulgating the CCR Rule the EPA cited hundreds of potential risks or incidents with ash ponds similar to Dan River that led to the adoption of the Rule. Based on the citing of these numerous incidents along with the timing of the CCR Rule, I would conclude that the Dan River accident did not change the CCR regulations, although it probably added support for the EPA's proposals.

[8] IBID, pages 35143, 35143.
[9] See Federal Register/Vol. 80, No. 74/Friday, April 17, 2015/Rules and Regulations, page 21343; 21393-94.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 123 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 17 of 44

Q. HOW DID THE ACCIDENTAL COAL ASH SPILL AT THE COMPANY'S DAN RIVER FACILITY IMPACT NORTH CAROLINA'S CAMA LAW?

A. Based on my review, it likely impacted the timing, but I cannot conclude that it impacted the substance of the standards. There is no doubt that the Dan River spill certainly helped prompt the North Carolina General Assembly to examine the State's and national coal ash disposal policies and regulations. Out of that legislative investigation came North Carolina's Coal Ash Management Act ("CAMA"). However, some four years prior to the Dan River accident, the EPA had already proposed and was close to finalizing its new coal ash regulations. I feel confident the EPA's proposed coal ash regulations helped inform the State's legislative leaders regarding the language contained in CAMA for several reasons. First, having served in the North Carolina General Assembly, I am sure that the legislative process leading to CAMA included an investigation of, and used where appropriate, the then current or proposed EPA coal ash standards. Second, there are many similarities between the proposed EPA rule and CAMA. For example, both discuss groundwater monitoring at length, both provide for the same two types of coal ash pond closure methods, the definitions used in both are very similar and sometimes use identical wording, and both contain three levels of hazardous potential classifications associated with coal ash ponds.[10]

[10] It should be noted that the risk levels identified in the EPA proposed rule were based on dam or dike structural integrity and the potential for loss of life or the level of economic harm. The levels of risk in CAMA considered structural integrity as one of several factors to consider and the risk was not strictly related to loss of life.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 124 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 18 of 44

Finally, the proposed CCR regulation also strongly encouraged the states to adopt at least the Federal minimum criteria in their solid waste management plans.[11] Therefore, even without the Dan River accident in 2014 and the enactment of CAMA shortly thereafter, had CAMA not been enacted in 2014, I believe that the State of North Carolina Legislature and/or the State's Department of Environmental Quality may have taken steps to adopt coal ash regulations similar to CAMA shortly after the CCR Rule was finalized in 2015. Regardless, the Company must comply with both the Federal and State coal ash disposal standards.

Q. ARE THERE ANY SOUTH CAROLINA STATE SPECIFIC LAWS OR GUIDELINES THAT THE COMPANY MUST FOLLOW IN ITS DISPOSAL OF CCRS?

A. Yes. For DE Progress in South Carolina there is one Consent Agreement with DHEC applicable to ash management at the Robinson Plant. The Robinson Consent Agreement, DHEC 15-23-HW, between Duke Energy Progress, Inc (now DE Progress) and DHEC, requires ash excavation of a 1960 lay-of-land ash storage area located south of the ash basin. This Consent Agreement also includes provisions to initiate permitting of an on-site CCR lined landfill to store the excavated ash.

Additionally, the South Carolina legislature passed H.B. 4857 in 2016, which requires utilities to dispose of coal combustion residuals resulting from the production of electricity to be placed in Class 3 landfills, except under

[11] Federal Register/Vol. 80, No. 74/Friday, April 17, 2015/Rules and Regulations, page 21430.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 125 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 19 of 44

limited circumstances.

Q. WHAT ARE THE SPECIFIC COAL ASH DISPOSAL STANDARDS THAT DE PROGRESS MUST NOW MEET WITH RESPECT TO ITS CURRENT COAL ASH DISPOSAL SITES?

A. Company Witness Kerin discusses these standards in detail. In short, the Company must comply with the 2015 Federal CCR Rule adopted by the EPA which established national minimum criteria for active CCR landfills and basins and inactive basins containing water, it must also comply with any CAMA obligations (which are similar to the CCR Rule as discussed by witness Kerin), and it must comply with the Robinson Consent Agreement as well as two Settlement Agreements[12] between the Company and North Carolina regulators and any other state agency requirements, such as those that may be required by DHEC.

IV. THE COMPANY'S PROPOSED COAL ASH COST RECOVERY PROPOSAL IS REASONABLE

Q. WHAT ARE THE COSTS THE COMPANY IS SEEKING TO RECOVER THAT YOUR TESTIMONY ADDRESSES?

A. DE Progress has reasonably and prudently incurred and expects to incur a total of $526.4 million (on a system basis) related to incremental ash pond closure compliance costs from July 2016 through December 2018.

[12] A Sept. 29, 2015 Settlement Agreement Between DE Progress and the North Carolina Department of Environmental Quality with regard to four generating facilities and an agreement between the Compoany and the same NC agency regarding the Asheville and H.F. Lee generating facilities.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 126 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 20 of 44

Q. THE COMPANY IS ALSO ASKING THE COMMISSION TO ALLOW THE COMPANY TO DEFER COAL ASH RELATED EXPENSES PENDING RECOVERY ADJUDICATION IN A FUTURE RATE CASE. IS THIS A COMMON PRACTICE UNDER SOUTH CAROLINA REGULATORY PROCEDURES?

A. Yes. A deferred account mechanism is not unusual in ratemaking. In his book discussing utility regulation Goodman indicates that "The use of deferred cost accounting in the ratemaking context is so common and so fundamental a regulatory tool that no agency is likely to consider it necessary to study whether as a matter of policy costs should be deferred..."[13] In Docket No. 2015-96-E (Order No. 2015-308) this Commission allowed the Company to defer costs associated with coal ash related environmental remediation costs. DE Carolinas also has a currently effective deferral approved in the Commission's Order in Docket No. 2016-196-E, dated July 13, 2016. DE Progress has a similar deferral that is ongoing, which was approved in the Order in Docket No. 2016-227-E, dated December 21, 2016.

Q. IS IT REASONABLE TO EXPECT CUSTOMERS TO PAY FOR THE DISPOSAL OF COAL ASH?

A. Yes. Those dollars are required to be spent in compliance with new coal ash disposal requirements. Such a circumstance is not new in the history of environmental regulations in the United States, where it is commonplace for restrictions to be modified and become more restrictive over time. For

[13] Goodman, Leonard, "The Process of Ratemaking," Public Utility Reports, Vienna, Va, 1998, p. 322.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 127 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 21 of 44

example, in our day-to-day life we have all experienced ever-tightening environmental restrictions on the automobiles we drive, as the emissions standards have grown increasingly stringent and more costly over the past few decades and the related costs have increased the costs of driving.

So, too, have electric utility generating plants been the focus of ever-tightening and more costly environmental standards. As an example, consider the evolution of coal gas smokestack emission standards, which are generally related to the federal Clean Air Act ("CAA") and its various updates or amendments.[14] The enactment of the CAA of 1970 resulted in a major shift in the federal government's role in air pollution control by authorizing the development of comprehensive federal and state regulations to limit emissions. The EPA was created on December 2, 1970, in large measure to implement the various requirements of the CAA.[15] Major revisions and stricter clean air standards were adopted as updates to the CAA in 1977 and 1990 and these new standards impacted coal-fired generating plants.[16]

Following the CAA 1990 amendments, the EPA devised a strategy to further reduce NOx emissions from coal-fired power plants by imposing tighter NOx emissions standards. In addition, in 1998, the EPA issued a rule that required 21 states (including North Carolina and South Carolina) to further reduce NOx emissions through the use of newer, cleaner control

[14] While sometimes the standards did not specifically target older coal-fired generating plants, invariably the more stringent standards would either impact a utility's total emissions limits, or a state's, consequently impacting even those older facilities that were not specifically targeted by newer emissions regulations.
[15] See: https://www.epa.gov/sites/production/files/2015-08/documents/peg.pdf.
[16] See: https://www.epa.gov/clean-air-act-overview/clean-air-act-requirements-and-history.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 128 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 22 of 44

strategies.[17].

Consequently, the history of environmental regulation is replete with examples of ever-tightening environmental regulations with the result being, with respect to utilities, the associated costs for meeting these ever-tightening environmental regulations usually becoming the responsibility of customers. Likewise, the issue of ever-tightening environmental regulations with respect to coal ash standards is the genesis of the Company's request as it relates to these new and additional coal ash disposal costs.

Q. ARE CERTAIN COAL ASH COSTS NOT RELATED TO COMPLIANCE WITH THE CCR RULE OR CAMA ALSO RECOVERABLE FROM CUSTOMERS?

A. Yes. As I mentioned earlier, DE Progress in South Carolina entered into a Consent Agreement with DHEC applicable to ash management at the Robinson Plant which requires ash excavation of a 1960 lay-of-land ash storage area located south of the ash basin. This Consent Agreement also includes provisions to initiate permitting of an on-site CCR lined landfill to store the excavated ash. Additionally, the Company entered into a Settlement Agreement with the South Carolina Office of Regulatory Staff and other parties related to the recovery of certain coal ash remediation costs, and this settlement was approved by this Commission in the aforementioned Order in Docket No. 2016-227-E, dated Dec. 21, 2016, page 11, paragraph 15. All of the costs related to the Robinson Plant Consent Agreement and costs related to

[17] See: http://instituteforenergyresearch.org/studies/the-facts-about-air-quality-and-coal-fired-power-plants/.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 129 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 23 of 44

the aforementioned Settlement Agreement must all be recovered, or in the latter case, continue to be recovered, even if these costs may be above those necessary to comply with the CCR Rule or CAMA.

Q. ARE THERE ANY COSTS RELATED TO CAMA THAT ARE IN EXCESS OF THE FEDERAL CCR RULE'S COSTS THAT ARE BEING REQUESTED IN THIS FILING?

A. This is discussed in Company Witness Kerin's testimony. As he discusses, there are some CAMA costs that are considered a system cost whose recovery is being requested, but there are other North Carolina resident-specific costs related to CAMA and not required by the CCR that the Company is not seeking to recover from South Carolina customers.

Q. DOES THE FACT THAT NEW STANDARDS WERE ADOPTED MEAN THAT DE PROGRESS' PAST PRACTICES WERE UNREASONABLE?

A. No. It is well established that the standard for determining the prudence of a utility's actions should be whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. To that end, a basic public utility regulatory principle is that a decision's prudency "must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 130 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 24 of 44

events based on subsequent developments — is not permitted."[18] In short, the Company's decisions related to coal ash disposal must be judged in accordance with the regulatory standards and industry practice as it existed at the time the decisions were made based on the fact that this was the information available to the Company at that time.

With respect to this prudence evaluation criteria, as discussed in the direct testimony of Company Witness Kerin, the Company historically has complied with all coal ash disposal regulations and used industry standard disposal operations for all its coal ash handling operations. Today, the coal ash disposal standards have simply changed and been updated as has occurred with many environmental standards over time. In the past, the Company was required to meet the coal ash disposal standards at the time, and so too it must now comply with the new coal ash disposal standards.

Q. IN YOUR OPINION ARE THE COAL ASH DISPOSAL COSTS THAT DE PROGRESS IS SEEKING TO RECOVER IN THIS CASE "USED AND USEFUL" UTILITY COST?

A. Yes. DE Progress's coal ash disposal sites have always been used and useful as part of the coal-fired generation production process. As I discussed earlier the Company's coal fired generating plants, whether located in South Carolina or North Carolina, have been used and useful and provided electric service that produced economic benefits to customers in South Carolina for decades. In addition, as referenced in the direct testimony of Company Witness Kerin,

[18] Phillips, Charles F., The Regulation of Public Utilities, Public Utilities Reports, Arlington, VA.,1993, p. 340.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 131 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 25 of 44

the Company has historically spent dollars in order to comply with the coal ash disposal regulations in effect at the time, and these dollars were a necessary expenditure related to used and useful utility costs made in the provision of electric service at the time. The Company was, and continues to be, obligated to meet the needs of its customers. This obligation to serve requires the disposal of coal ash subject to the disposal standards at the time, thereby rendering the disposal sites for this coal ash, for which costs DE Progress seeks recovery in this case, "used and useful" in providing electric service. In addition, it should be noted that these same costs were just found to be "used and useful" in three different proceedings in North Carolina including the Company's proceeding last year where the North Carolina Commission specifically stated that these type of costs were "used and useful in the provision of service to the Company's customers (Order, Docket E-2, Sub 1131, page 18).

Q. HAS THE COMMISSION ALREADY ADDRESSED THE RECOVERY OF THESE SPECIFIC TYPE OF COAL ASH DISPOSAL COSTS WITH ANOTHER ELECTRIC UTILITY?

A. Yes. As I mentioned, in Docket No. 2016-227-E, DE Progress was allowed to recover these same coal ash expenses, albeit the Order did state that this finding had no precedential effect and will not prejudice the position of any Party in any future proceeding before the Commission.[19]

[19] Order in Docket No. 2016-227-E, Dec. 21, 2016, page 11, paragraph 15.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 132 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 26 of 44

Q. ARE THERE EXAMPLES OF UTILITY INFRASTRUCTURE PROJECTS THAT DEALT WITH AN ENVIRONMENTAL ISSUE AND COST RECOVERY THAT IS SIMILAR IN NATURE TO THE COAL ASH ISSUE IN THIS FILING?

A. I believe a similar situation that is instructive are the ongoing costs related to gas pipeline safety and integrity. Like coal ash regulations, these pipeline safety and integrity regulations have changed and become more costly over the past few years. For example, in 2011 the DOT and Pipeline and Hazardous Materials Safety Administration ("PHMSA"), promulgated regulations that require inspection, repair, rehabilitation and/or replacement of the highest risk natural gas pipeline infrastructure by pipeline operators. The program included an inventory of pipelines by type, system evaluation to identify risks and an implementation plan to mitigate those risks. South Carolina natural gas systems have had expeditures to comply with these new regulations and South Carolina Electric & Gas Company has been allowed to collect these costs through a deferral mechanism, including a return, and collect these costs over time (Docket. No. 2014-461-G, see filings dated Dec. 3, 2014, ORS filing dated Dec. 10, 2014, and Commission Directive dated Dec. 17, 2014).

Q. ARE THERE OTHER EXAMPLES OF ENVIRONMENTAL COST RECOVERY SIMILAR TO THE COST RECOVERY OF COAL ASH DISPOSAL?

A. Yes. As I mentioned earlier in this testimony, in this Commission's Docket

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 133 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 27 of 44

No. 2011-271-E, costs associated with a Cliffside scrubber were amortized and in the rate base. In addition, in Docket No. 2009-226-E costs associated with scrubbers at the Allen Steam Station were amortized and in rate base.

Q. ARE THERE POTENTIAL COST SHARING LIABILITIES RELATED TO THESE COAL ASH DISPOSAL COSTS THAT MIGHT MATERIALIZE AND THUS DIMINISH THE OVERALL COST IMPACTS ON CUSTOMERS?

A. Yes. The Company has filed insurance litigation. When and if those monies materialize, customers should see the benefit of those proceeds, like spent fuel litigation. However, these cases can take many years to finally resolve. It would be appropriate for the Commission to monitor these cases and ensure that any outcome benefits customers. It is my understanding that the Company has no objection to that approach.

Q. ARE THERE WAYS THAT THE COMPANY MIGHT SUGGEST THAT THE COMMISSION COULD ADOPT AS A MEANS OF MITIGATING THE OVERALL RATE IMPACT FROM THESE NEW ADDITIONAL COSTS?

A. Yes. For example, it is not unusual for such costs to be stretched out over a number of years so that the impact on rates is more manageable. If that type of option is adopted, however, then it is appropriate for the utility to receive carrying costs to ensure it is made whole for all costs.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 134 of 168
ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 28 of 44

Q. BECAUSE ONLY PRUDENTLY INCURRED COSTS ARE RECOVERABLE, HAVE YOU EXAMINED WHETHER THE ACTUAL DOLLARS BEING REQUSTED BY THE COMPANY ARE REASONABLE AND PRUDENT?

A. I have examined the filing, many of the Federal and State laws related to coal ash disposal, the testimony of Company Witness Kerin and other Company witnesses, reviewed past Commission Orders regarding environmental cost recovery, discussed with the Company its history related to coal ash disposal, and reviewed the more recent settlement agreements related to coal ash disposal. Based on my review, I believe that the Company is in the best position to address coal ash disposal and the related costs in conformance with State and Federal coal ash disposal requirements and I believe their actions in this regard are prudent.

Q. DO YOU BELIEVE THE COMPANY'S COAL ASH COST RECOVERY PROPOSAL IS REASONABLE?

A. Yes. I believe that the Company's proposals to recover its costs for complying with updated coal ash disposal regulations are reasonable and consistent with the historical regulatory treatment of similar costs.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY AT THIS TIME?

A. Yes.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 135 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 29 of 44

Dr. Julius A. "Chip" Wright
J. A. Wright & Associates, LLC

Julius A. "Chip" Wright is the President of J. A. Wright and Associates, LLC
18 Edgewater Drive
Cartersville, GA 30121
770-365-1872
jawright@mindspring.com.

Experience Overview

Prior to starting his firm, Dr. Wright was a Client Partner for AT&T Solutions Utilities and Energy Practice and before that a Principal in EDS' Management Consulting Services. Dr. Wright has been consulting electric gas, and telephone utilities on regulation, economics, rates, production modeling and strategic planning for the past three years. Prior to this Dr. Wright served an eight-year term as a Utility Commissioner for the state of North Carolina. Prior to that he served three terms in the North Carolina State Senate while he was a senior project engineer for Corning Glass Works on their optical wave guide project in Wilmington, North Carolina. He has a total of 14 years' government-related experience, 12 years' plant-related engineering experience, and he has established two companies.

Dr. Wright (in 2011) has also been a Visiting Professor at the University of the Virgin Islands teaching sophomore courses in both Macro and Micro Economics.

While serving on the North Carolina Utility Commission, he served four years on the National Association of Regulatory Utility Commissioners (NARUC) Electricity Committee. He has served in various other advisory capacities, including the Keystone

Committee on Externalities; the North Carolina Radiation Protection Committee, and on an Oversight Committee for a joint North Carolina/New York/ Department of Energy (DOE) project.

Dr. Wright has also served on the Southern States Energy Board Task Force on Restructuring the Electric Utility Industry.

Regulatory Policy Issues, Prudence Reviews and Regulatory Studies

- Presented testimony and rebuttal testimony to the North Carolina Utility Commission in support of Duke Energy Carolinas' efforts to recovery coal ash remediation costs the Company incurred in response to new coal ash disposal costs, Feb., 2017, Docket No. E-7, Sub 1146.

- Presented testimony and rebuttal testimony to the North Carolina Utility Commission in support of Duke Energy Progress' efforts to recovery coal ash remediation costs the Company incurred in response to new coal ash disposal costs, June and November, 2017, Docket No. E-2, Sub 1146.

- Prudence review: report for Georgia Power Company regarding the prudence of Plant Vogtle new nuclear construction costs, "*The South Carolina Public Service Commission's Prudence Reviews of Summer Units 2 and 3 as Persuasive*

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 136 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 30 of 44

Precedent for the Georgia Public Service Commission's Regulatory Treatment of Vogtle Units 3 and 4," April 5, 2016, Georgia Public Service Commission, Docket No 29849.

- Regulatory study: *"The Economic and Rate Implications from an Electric Utility's Loss of Large Load Customers,"* presented in rebuttal testimony for Progress Energy Carolinas, North Carolina Utility Commission Docket No. E-2, Sub 1023, March 4, 2013.
- Regulatory study: Dr. Wright routinely provides testimony support and witness training to several Fortune 500 investor-owned utilities in the Southeast, most recently involving two rate cases (2011, 2012) and three rate related cases dealing with an ongoing nuclear construction project (2008, 2010, 2012).
- Prudence review: related to a review of affiliate cost structure relative to compliance with FERC Order 707, conducted for a major SE utility, 4th quarter, 2008.
- Prudence review: related to a review of Affiliate Cost for Service Company Charges to a Regulated Utility, study conducted for SCANA Corporation, May, 2008.
- Regulatory study: review of Electric Utility Formula Rate Plans and specific Entergy formula rate plans, conducted for Entergy Mississippi, Jan-May, 2008.
- Prudence review: June 2005, provided a financial analysis related to the options for collecting and saving nuclear plant decommissioning costs for Duke Energy and this study along with a presentation was provided to the North Carolina Public Utility Commission and Staff.
- Regulatory study: provided analysis for Entergy Mississippi that was presented to the Mississippi Public Service Commission related to the valuation of services that Company provided to an unregulated affiliate, November 2002.
- Prudence review: *"Energy Deregulation,"* March 2001, report of the California State Auditor on the causes of the problems related to high electric prices and blackouts (from May, 2000 through June 2001, and ongoing) in California's restructured electric marketplace. Dr. Wright was one of three consultants who essentially researched and prepared the State Auditor's report.
- Prudence review: Principal author with Dr. Al Danielsen of *"Reliability of Electric Supply In Georgia,"* published by The Bonbright Utilities Center,

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 137 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 31 of 44

University of Georgia, June, 2001.

- Regulatory study: Presented testimony before the North Carolina Public Utilities Commission on behalf of SCANA Corporation regarding issues related to market power in its merger with Public Service Company of North Carolina, Docket No. G-5, Sub 400; G-3, Sub 0.

- Prudence review: was the principal author of a report and investigation titled "*An Analysis of Commonwealth Edison's Planning Process For Achieving Reliability of Supply*," which was an investigation of the Company's planning process to meet its statutory obligation for supplying electricity as Illinois transitions to a competitive retail electric market, Illinois Commerce Commission Docket No. 98-0514.

- Regulatory study: co-authored a national study that used computer modeling techniques to quantify the impact of electric competition on the aggregate economy in each of the 48 continental United States.

- Regulatory study: presented testimony to Louisiana Legislative Committee on behalf of Entergy Corporation regarding the various regulatory and technical issues that need to be addressed in the transition to competition.

- Regulatory study: presented testimony For Virginia Power with regard to its transition to competition plan.

- Regulatory study: testified before the Mississippi Public Service Commission on issues related to the establishment of retail electric competition, including ISO establishment, regional power exchanges, legislation, taxes and regulatory polices.

- Regulatory study: presented testimony for Entergy Corp. in both Louisiana and Arkansas in support of its transition to competition filing.

- Regulatory study: worked with three major southeastern utilities on developing business and regulatory strategy as they prepare for competition.

- Regulatory study: filed a report with the South Carolina Legislature that studied the impact of electric competition on the state of South Carolina.

- Was a panelist on a Southern Gas Association national televised forum on performance based regulation for the natural gas industry.

- Regulatory study: Was the lead policy witness for South Carolina Electric and Gas on obtaining regulatory approval to transfer of depreciation reserve from a nuclear plant to T&D

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 138 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 32 of 44

depreciation reserve. This is a critical issue in preparing for competition and limiting stranded investment.

- Developed regulatory and marketing strategy for Entergy with regard to its telecommunications initiatives. In these efforts he worked with the EDS Telecommunications Consulting Group.

- Prudence review: was the lead analysis of the prudence of Central Vermont Public Service Company's power and resource acquisitions over a five year period. The prudence of this utility's power supply strategy was under investigation in a rate case proceeding. Dr. Wright's team filed testimony supporting the Company and their efforts were instrumental in undermining the charges of imprudence brought by the Company's opposition.

- Regulatory study: developed an EDS intra-company task force to address the issues related to FERC's Transmission NOPR. This task force subsequently filed three responses to FERC's Open Access NOPR which provide a basis for EDS to maintain a leadership position as the electric utility industry undergoes restructuring to a competitive market.

- Regulatory study: helped develop a regulatory strategy and presented testimony on behalf of South Carolina Pipeline. In this case, an economic analysis prepared by Dr. Wright and Dr. Frank Cronin (from EDS Economic Planning and Analysis Consulting Group) was presented along with recommendations. The analysis and recommendations were generally accepted by the Commission staff.

- Prudence reviews: as a North Carolina Utility Commissioner Dr. Wright was involved in the prudence reviews of the costs related to the construction of three nuclear plants, Catawba 1 & 2 and Shearon Harris. In addition, he was involved in several other prudence reviews of various utilities.

Resource Planning & Economic Analysis

As a Commissioner he has been involved in a variety of resource planning issues including chairing the last North Carolina Resource Planning hearing that involved Duke Power Company, Carolina Power and Light, Virginia Power Company and the North Carolina Electric Membership Corporation.

He was also selected by the states of North Carolina and New York and the Department of Energy to be one of five representatives on a peer review panel overseeing a Resource Planning project being conducted by the Oak Ridge National Laboratories. In addition to these initiatives Dr. Wright has:

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 139 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 33 of 44

- *"The Economic and Rate Implications from an Electric Utility's Loss of Large Load Customers,"* presented in rebuttal testimony for Progress Energy Carolinas, North Carolina Utility Commission Docket No. E-2, Sub 1023, March 4, 2013.

- Provided an analysis of electric vehicle economics and the legislative, engineering, and regulatory issues that regulated electric utilities should address in both residential and commercial installments of electric vehicle charging stations. Studied performed for Fortune 500 Southeastern investor-owned utilities, 2011-2012.

- Provided a study to a Fortune 500 large Southeastern investor-owned utility related to the use of regulated electric rates designed to help retain current large industrial customers, 2012.

- Provided a Fortune 500 large Southeastern based investor-owned electric utility an economic, engineering, and environmental evaluation of a proposed renewable fuel alternative including the provision of an assessment and the design for a large-scale pilot test in one of that utility's fossil-fired facilities, 2012.

- Provided testimony for Entergy Mississippi related to whether the Mississippi Public Service Commission should adopt some proposed Federal standards related to integrated resource planning and energy efficiency, Docket No. 2008-AD-477, February 2009.

- Provided a report to Entergy Mississippi on fuel cost recovery mechanisms that included a nationwide survey of fuel adjustment mechanisms, 2008.

- Provided testimony in North Carolina for Duke Energy related to whether the North Carolina Public Utility Commission should approve the recovery of nuclear generation project development costs, Docket No. E-7-Sub 819, April 2008.

- Provided a review for Duke Energy of the cost assumptions and regulatory initiatives related to new nuclear plant construction nationwide, April 2008.

- Provided analysis for Entergy Mississippi related to new nuclear plant applications and any new regulatory mechanisms adopted by various states related to the approval or cost recovery associated with these new nuclear plants, April 2008.

- Presented testimony on behalf of Entergy Mississippi on its IRP or electric resource plan and demand side initiatives, June, 2008, Docket No. 2008-AD-158.

- Provided testimony in Georgia for Georgia Power Company supporting that Company's Integrated Resource Planning

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 140 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 34 of 44

process, the appropriate methods for evaluating demand side energy options, and supporting that Company's planned demand side programs, Docket No. 24505-U, June 2007.

- Provided testimony in North Carolina for Duke Energy and Progress Energy related to the regulatory and economic rationale and appropriateness for using the "peaker" methodology and other methodologies for the establishment of avoided cost rates, Docket No. E-100-Sub 106, June 2007.

- Provided analysis for Entergy Mississippi that was presented to the Mississippi Public Service Commission related to the valuation of services that Company provided to an unregulated affiliate, November 2002.

- Was the lead policy witness for South Carolina Electric and Gas on obtaining regulatory approval to transfer depreciation reserve from a nuclear plant to T&D depreciation reserve. This is a critical issue in preparing for competition and limiting stranded investment.

- Was instrumental in acquiring a large engagement for a major southeastern utility examining their competitive position as it relates to a competitive electric market. During the engagement he provided input and guidance on regulatory issues related to the deregulation of the electric industry.

- Assisted Carolina Power and Light Company in their integrated resource planning process by advising and facilitating a Commission directed public policy panel.

- Developed an overview of Niagara Mohawk Gas' integrated resource planning efforts. This engagement was under a contract from Oak Ridge National Laboratories.

Renewable Fuels, Demand Side, Energy Efficiency

- Provided an analysis of electric vehicle economics and the legislative, engineering, and regulatory issues that regulated electric utilities should address in both residential and commercial installments of electric vehicle charging stations. Studied performed for Fortune 500 Southeastern investor-owned utilities, 2011-2012.

- Provided a Fortune 500 large Southeastern based investor-owned electric utility an economic, engineering, and environmental evaluation of a proposed renewable fuel alternative including the provision of an assessment and the design for a large-scale pilot test in one of that utility's fossil-fired facilities, 2012.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 141 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 35 of 44

- Provided testimony for Entergy Mississippi related to that Company's proposed new demand side initiatives Docket No. EC-123-0082-00, February 2009.

- Provided testimony for Entergy Mississippi related to whether the Mississippi Public Service Commission should adopt some proposed Federal standards related to integrated resource planning and energy efficiency, Docket No. 2008-AD-477, February 2009.

- Presented testimony on behalf of Public Service of North Carolina supporting that Company's proposed demand side initiatives as well as the cost recovery of those initiatives, Docket No. G-5, Sub 495, March 2008.

- Provided testimony in South Carolina for Duke Energy, South Carolina Electric and Gas, and Progress Energy related to whether the South Carolina Public Service Commission should adopt some proposed Federal standards related to smart metering and energy efficiency rate setting procedures, Docket No. 2005-386-E, April, 2007.

- Provided testimony in South Carolina for South Carolina Electric and Gas related to Integrated Resource Planning and that Company's demand side initiatives, June 2007.

- Provided testimony in Georgia for Georgia Power Company supporting that Company's Integrated Resource Planning process, the appropriate methods for evaluating demand side energy options, and supporting that Company's planned demand side programs, Docket No. 24505-U, June 2007.

- Provided testimony in North Carolina for Duke Energy and Progress Energy related to whether the North Carolina Public Utility Commission should adopt some proposed Federal standards related to smart metering, energy efficiency, and electric resource planning, Docket No. E-100-Sub 108, November 2006.

Nuclear Issues

- Prudence review: report for Georgia Power Company regarding the prudence of Plant Vogtle new nuclear construction costs, "*The South Carolina Public Service Commission's Prudence Reviews of Summer Units 2 and 3 as Persuasive Precedent for the Georgia Public Service Commission's Regulatory Treatment of Vogtle Units 3 and 4,*" April 5, 2016, Georgia Public Service Commission, Docket No 29849.

- Dr. Wright provided testimony support and witness training involving three rate related cases dealing with an ongoing nuclear

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 142 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 36 of 44

construction project (2008, 2010, 2012).

- Provided testimony in North Carolina for Duke Energy related to whether the North Carolina Public Utility Commission should approve the recovery of nuclear generation project development costs, Docket No. E-7-Sub 819, April 2008.

- August 2008 provided a study to Duke Energy Carolinas examining the issue of cost justification for new nuclear power facilities.

- June, 2005, provided a financial analysis related to the options for collecting and saving nuclear plant decommissioning costs for Duke Energy and this study along with a presentation was provided to the North Carolina Public Utility Commission and Staff.

Cost of Service, Rate Design, Forecasting

While serving more than eight years on the North Carolina Commission, Dr. Wright was involved in several cost of service and rate design analyses, testimonies, and orders. This included work in electric, telephone, gas, and water utilities. Additionally, he has presented testimony on performance based ratemaking and he has been involved in analyzing electric utility forecasting models, including end-use models, regression analysis (both linear and nonlinear) and customer discrete choice modeling forecasts. Furthermore, Dr. Wright's Ph.D. is in environmental and regulatory economics with special research into nonlinear minimal cost optimization procedures for electric utility production models. This work included optimizing investments, optimal regulatory regimes, pricing, cost recovery, and rate of return issues.

In addition, he has:

- *"The Economic and Rate Implications from AN Electric Utility's Loss of Large Load Customers,"* presented in rebuttal testimony for Progress Energy Carolinas, North Carolina Utility Commission Docket No. E-2, Sub 1023, March 4, 2013.

- Provided a study to a Fortune 500 large Southeastern investor-owned utility related to the use of regulated electric rates designed to help retain current large industrial customers, 2012.

- Presented testimony on behalf of Public Service of North Carolina related to the establishment of a formulary type rate setting mechanism for this natural gas LDC, August 2008, Docket No. G-5, Sub 495.

- Provided testimony in Georgia for Georgia Power Company supporting that Company's methodology for pricing fuel and its use of marginal replacement fuel cost procedures in its intra-company resource sharing arrangement with the Southern company, Docket No. 191142-U, April 2005.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 143 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 37 of 44

- Provided an economic analysis of the proper regulatory regime for South Carolina Pipeline Company. In this analysis he presented testimony supporting performance based ratemaking and his recommendations were generally accepted by the Commission staff.

- Developed forecasted rates for two New York state utilities. These rates were developed to support a bond filing by a co-generator.

- Provided a forecast of power payments from New York State Electric and Gas (NYSEG) to two independent power producers (IPPs). This forecast was used to estimate the level of overpayments by NYSEG to these IPPs, under PURPA regulations, which he used in a filing before FERC supporting the company's claim of unlawful overpayments.

Telecommunications

As a Commissioner he has regulated all types of telecommunications providers for eight years. In addition, he has worked with two electric utilities in strategy formulation in regard to their entering the telecommunications business. Furthermore, he has eight years experience as a fiber optic engineer.

Other Areas of Expertise

Prior to joining EDS, he worked for eight years as a senior process engineer for Corning Glass in the design and production of optical waveguides (or fiber optics). Prior to that he worked for four years in the chemical industry as a process chemist and later as a senior project engineer. He has done work in environmental monitoring, process and product improvement, plant utilization, as well as starting and selling two successful companies – one in the financial leasing business and the other in the entertainment industry.

Presentations and Publications

Report for Georgia Power Company regarding the prudence of Plant Vogtle new nuclear construction costs, "*The South Carolina Public Service Commission's Prudence Reviews of Summer Units 2 and 3 as Persuasive Precedent for the Georgia Public Service Commission's Regulatory Treatment of Vogtle Units 3 and 4,*" April 5, 2016, Georgia Public Service Commission, Docket No 29849.

"*The Economic and Rate Implications from AN Electric Utility's Loss of Large Load Customers,*" presented in rebuttal testimony for Progress Energy Carolinas, North Carolina Utility Commission Docket No. E-2, Sub 1023, March 4, 2013.

"*Energy Deregulation,*" March 2001, report of the California State Auditor on the causes of the problems related to high electric prices and blackouts (from May, 2000 through June 2001, and ongoing) in California's restructured electric marketplace. Dr. Wright was one of three consultants who essentially researched and prepared the State Auditor's report.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 144 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 38 of 44

"Low Cost States and Electric Restructuring -
The Issue is the Price!" presented to the 1999 Miller Forum on Government, Business and the Economy, University of Southern California, April 19, 1999.

An Analysis of Commonwealth Edison's Planning Process For Achieving Reliability of Supply, Illinois Commerce Commission Docket No. 98-0514.

The Impact of Competition on the Price of Electricity, author, published by L. A. Wright and Associates, November, 1998.

"Retail Competition in the Electric Industry: The Impact on Prices," presented at the 18th Annual Bonbright Center Energy Conference, Atlanta, Georgia, Sept. 10, 1998.

Potential Economic Impacts of Restructuring the Electric Utility Industry, co-author, published by the Small Business Survival Committee, Washington, DC, November, 1997.

"How Deregulation Will Affect Power Quality and Energy Management," presented at the Power Quality and Energy Management Conference co-sponsored by Entergy and EPRI, New Orleans, LA, Nov. 14, 1997.

"Deregulation of the Electric Industry," *Proceedings: National Business Energy Forum*, June 26, 1997, New Orleans, LA.

"A Different View of the Market," presented at the Southeastern Electric Exchange Conference, June 25, 1997, Charlotte, N.C.

"Restructuring The Electric Utility Industry: Theory vs. Reality," presented at the American Bar Association Restructuring Conference, Raleigh, NC, Dec. 5, 1996.

"Restructuring: The Best Approach for Virginia," presented at the Virginia State Corporation Commission Electricity Restructuring Forum, Charlottesville, VA, Nov. 15, 1996.

"Alternative Rate Making for the Natural Gas Industry: State Issues," presented at the Tenth Annual NARUC Biennial Regulatory Information Conference, Columbus, Ohio, Sept. 12, 1996.

"RetailCo: To Regulate or Not?" presented at the 9th Annual Automatic Meter Reading Symposium, New Orleans, La., Sept. 10, 1996.

"Convergence: The Competitive Revolution Comes To Electric Power," presented to the Southeastern Association of Regulatory Commissioners Annual Convention, Point clear, Alabama, June 4,1996.

"Stranded Assets Recovery Issues," presented at the Western Electric Power Institute: Financial Forum, Tucson, Arizona, March 8, 1996.

"The Deregulation of the Electric Utility Industry : Current Status," presented at the North Carolina Economic Developers Association Midwinter Conference, Pinehurst, N.C., February 23, 1996.

"Performance Based Regulation for The Natural Gas Industry," panelist on Southern Gas Association's Televised

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 145 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 39 of 44

Regulatory Forum, Dallas, Texas, Jan. 18, 1996.

"Industry Structure Should Meet Stakeholder Objectives," *Electric Light and Power*, Jan., 1996.

"Quantifying the Value of Stranded Investment: A Dynamic Modeling Approach," *Proceedings: Implementing Transmission Access and Power Transactions Conference*, Denver, Colorado, Dec. 14, 1995.

"Quantifying the Value of Stranded Investment: A Dynamic Modeling Approach," at the 15th Annual Bonbright Center Electric and Natural Gas Conference, October 9-11, 1995, Atlanta, Georgia.

Comments to FERC in the matter of Notice of Proposed Rulemaking on Open Access, Docket No. 95-9-000, 1995.

"The Road to Competition for Re-Regulated Industries," presented at the 1995 PROMOD users Forum, St. Petersburg, Florida, May 1, 1995.

"*Comparing New York State Electric and Gas Corporation's Non-Utility Generator Payments to Current Avoided Cost Rates*," report submitted in support of affidavit filed before FERC in Docket No. EL 95-28-000.

"A Solution To The Transmission Pricing and Stranded Investment Problems" *Public Utilities Fortnightly*, January 1995.

"Electric Utility Competition: The Winning Focus," presented at 1994 Southeastern Electric and Natural Gas Conference, Atlanta, Georgia, October 1994.

"*Gas Integrated Resource Planning: The Niagara Mohawk Experience*," for Martin Marietta Energy Systems, Inc., under contract to the United States Department of Energy, ORNL/SUB/93-03369.

"Future Regulation In the Water Industry - Can We Solve the Problems Before They Happen?" *Water*, Vol. 29, No. 2, pp. 14-17, Summer 1988.

"The Regulatory Process - Historical and Today," presented at Carolina Power and Light Company's IRP Public Participation Committee Seminar, June 1994.

"The Regulatory Role In DSM: Who Pays?" presented at Carolina Power and Light Company's IRP Public Participation Committee Seminar, June 1994.

"The Regulatory Process In North Carolina," North Carolina Telephone Association, June 1991.

Testimony

- Presented testimony and rebuttal testimony to the North Carolina Utility Commission in support of Duke Energy Carolinas' efforts to recovery coal ash remediation costs the Company incurred in response to new coal ash disposal

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 146 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 40 of 44

costs, Feb., 2017, Docket No. E-7, Sub 1146.

- Presented testimony and rebuttal testimony to the North Carolina Utility Commission in support of Duke Energy Progress' efforts to recovery coal ash remediation costs the Company incurred in response to new coal ash disposal costs, June and November, 2017, Docket No. E-2, Sub 1146.

- Presented testimony before the Mississippi Public Service Commission on behalf of Entergy Mississippi, Inc., in support of that company's revisions to its Formula Ratemaking procedures, Docket No. 2014-UN-132, June 2014.

- Rebuttal testimony for Progress Energy Carolinas, related to the economic and rate implications from an electric utility's loss of large load customers, North Carolina Utility Commission Docket No. E-2, Sub 1023, March 4, 2013.

- Provided a study to a Fortune 500 large Southeastern investor-owned utility related to the use of regulated electric rates designed to help retain current large industrial customers, and developed proposed testimony in support of this issue, 2012.

- Provided an affidavit in support of Progress Energy Carolinas to the North Carolina Utility Commission in a proceeding considering the appropriate avoided cost rates that should be paid to an independent power producer, Sept., 2010, Docket No. E-2, Sub 966.

- Presented testimony on behalf of Entergy Mississippi in an investigation of the Commissions procedures concerning confidentiality, August, 2010, Docket No. 2010-AD-259.

- Presented testimony before the Mississippi Public Service Commission on behalf of Entergy Mississippi, Inc.., in support of the formula rate plan annual evaluation, Docket No. 2002-UN-526, March, 2009.

- Presented testimony before the Mississippi Public Service Commission on behalf of Entergy Mississippi, Inc., in support of an energy efficiency pilot program and cost recovery mechanism, Docket No. 2009-UN-064, February, 2009.

- Presented testimony before the Mississippi Public Service Commission on behalf of Entergy Mississippi, Inc., in a proceeding to review statewide energy generation needs, Docket 2008-AD-270, August 2008.

- Presented testimony on behalf of Public Service of North Carolina related to the establishment of a formulary type rate setting mechanism for this natural gas LDC, August, 2008, Docket No. G-5, Sub 495.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 147 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 41 of 44

- Presented testimony on behalf of Entergy Mississippi in an investigation of that utility's fuel charges and its fuel cost recovery, July, 2008, Docket No. 2008-AD-270.

- Presented testimony on behalf of Entergy Mississippi on its IRP or electric resource plan and demand side initiatives, June, 2008, Docket No. 2008-Ad-158.

- Presented testimony for Duke Energy in North Carolina related to the approval to incur pre-construction costs for the proposed Lee Nuclear Station, Docket No. E-7, Sub 819, May, 2008.

- Presented testimony for Duke Energy in South Carolina related to the approval to incur pre-construction costs for the proposed Lee Nuclear Station, Docket No. 2007 -440-E, June, 2008.

- Presented rebuttal testimony for Duke Energy in North Carolina related to the recovery of costs incurred by Duke related to GridSouth and why these expenses should be fully recoverable at this time, Docket No. E-7, Sub 828, October, 2007.

- Provided testimony for Georgia Power in its 2007 Integrated Resource Plan reviewing the plan filed by the Company and discussing how its demand-side proposals were reasonable, compared the Company's demand-side proposals to those found in neighboring states, and discussed the application of the various tests used to evaluate demand-side programs (TRC, RIM, PTC), Docket number 24505-U, May, 2007.

- Presented two testimonies before the South Carolina Public Service Commission on behalf of South Carolina Electric and Gas, Duke Energy and Progress Energy Carolinas in the investigation of adoption of energy efficiency and generation standards related to the Energy Policy Act of 2005, Dockets No. 2005-385-E and No. 2005-386-E, April, 2007.

- Presented testimony before the North Carolina Public Utilities Commission on behalf of Duke Energy and Progress Energy Carolinas in the investigation of adoption of energy efficiency and generation standards related to the Energy Policy Act of 2005, Docket No. E-100, Sub 108 November 2006.

- Presented testimony before the North Carolina Public Utilities Commission on behalf of Duke Energy in the investigation of Duke Energy's 2006 Integrated Resource Plan, Docket No. E-100, Sub 103, June, 2006.

- Provided testimony for Georgia Power in its 2005 Fuel Adjustment Hearing on the issue of the appropriate pricing

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 148 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 42 of 44

methodology for the dispatch and sale of electricity in the Southern Company system, Docket number 19142-U, April, 2005.

- Presented testimony on behalf of South Carolina Electric and Gas Company before the South Carolina Public Utility Commission for South Carolina Pipeline Company related to the inclusion of a generating plant in rate base and to the recovery of RTO (Gridsouth) related costs, Docket No. 2004-178-E, October, 2004.

- Presented testimony on behalf of Entergy Mississippi before the Mississippi civil court dealing with maintaining the confidentiality of special use contracts, August, 2004.

- Presented rebuttal testimony before the South Carolina Public Utility Commission for South Carolina Pipeline Company related to the reasons for continuing a program that allows flexible, competitive based pricing for large, interruptible customers that have alternative fuels, Docket No. 2004-6-G, May 29, 2004.

- Presented testimony before the Georgia Public Service Commission on the appropriate range for a return on equity earnings band (a form of performance based regulation) to set in a Savannah Electric & Power Company rate case, Docket No. 14618-U, April, 2002.

- Presented testimony before the Georgia Public Service Commission on behalf of Scana Energy Marketing related to affiliate relationships and the appropriate affiliate rules between Atlanta Gas Light Company's regulated and unregulated affiliates. Docket No. 146060-U, August 24, 2001.

- Presented testimony before the Georgia Public Service Commission on the appropriate range for a return on equity earnings band (a form of performance based regulation) to set in a Georgia Power Company rate case, Docket No. 14000-U, November 19, 2001.

- Presented testimony before the North Carolina Public Utilities Commission on behalf of SCANA Corporation regarding issues related to market power the appropriate affiliate relationship protections necessary in its merger with Public Service Company of North Carolina, Docket No. G-5, Sub 400; G-3, Sub 0.

- Presented testimony before the South Carolina Public Service Commission on behalf of South Carolina Pipeline Corporation regarding issues related to its annual review of gas costs as reflected in its purchase gas adjustment charge, Docket No. 1999-007-G, September, 1999.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 149 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 43 of 44

- Presented testimony before the Arkansas Public Service Commission on behalf of Entergy Arkansas, Inc. regarding regulatory policies related to the definition of public utilities as it impacts citing requirements of non-utility owned generating facilities, Dockets No. 98-337-U, March 9, 1999.
- Presented Rebuttal and Surrebuttal testimony before the Louisiana Public Service Commission on behalf of Entergy Louisiana, Inc. and Entergy Gulf States regarding regulatory policies related to stranded cost recovery and on the issue of whether investors have been compensated for the risk of not recovering stranded costs, Dockets Nos. U-22092SC and U-20925, September, 1998.
- Presented testimony to the South Carolina Public Utility Commission for South Carolina Pipeline Corp. related to acquisition adjustments and regulatory policies related to performance based regulation, Docket No. 90-588-G, June, 1998.
- Testified before the Mississippi Public Service Commission on issues related to the establishment of retail electric competition, including ISO establishment, regional power exchanges, legislation, taxes and regulatory polices, April 16, 17, 1997.
- Support of Transition Proposals filed by Virginia Power Corporation, March, 1997.
- Entergy Arkansas testimony in support of Transition to Competition Filing, 1997.
- Entergy Louisiana testimony in support of Transition to Competition Filing, 1997.
- Support of Performance Based Regulation for GTE South Inc., Docket No. P-19, Sub 277, before the North Carolina Utility Commission, filed Nov. 22, 1995.
- Stranded Cost Regulatory Policy and Recovery Testimony before the South Carolina Public Service Commission, the Commission approved the request Dr. Wright was advocating, Docket No. 95-1000-E, October 27,1995.
- Performance based rate making mechanism and rate levels, testimony on behalf of South Carolina Pipeline Corporation, Docket No. 90-588-G, filed August 3, 1995.
- Prudence Review of Power Resource Planning for Central Vermont Public Service Company, Docket No. 5724, September 7, 1994.
- Rebuttal testimony on behalf of Central Vermont Public Service Company, Docket 5724, September 7, 1994.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 150 of 168

ELECTRONICALLY FILED - 2018 November 8 10:24 AM - SCPSC - Docket # 2018-318-E - Page 44 of 44

- Surrebuttal testimony on behalf of Central Vermont Public Service Company, Docket No. 5724, September 9, 1994.

Education

Dr. Wright received a Ph.D. in Economics from North Carolina State University, focusing on regulatory and environmental economics, and is a member of the honor society.

He received an MBA in finance from Georgia State University in 1978, graduating with honors.

He received a Master of Economics from North Carolina State University in 1991 and was a member of the honor society.

He received a B.S. in Chemistry from Valdosta State College in Valdosta, Georgia, graduating Magna Cum Laud.

In addition, he has completed the Michigan State University Regulatory Course, several other NARUC courses on regulation, been an instructor on regulatory issues at several NARUC courses, completed management courses at Corning Glass and financial seminars at Bank Boston and Merrill Lynch dealing with regulation.

Dr. Wright (in 2011) has also been a Visiting Professor at the University of the Virgin Islands teaching sophomore courses in both Macro and Micro Economics.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 151 of 168

Duke Energy Progress
ORS Data Request 31-1 c and d
Descriptions of monthly expenditues on Fossil Ash Basin Initiative projects

Sum of Monetary Amount 2		Accounting Period CMD												
Project ID CB	Project Short Descr CB	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
20087848	01RX0CRP4 BA CONV&NON SCRUB WW												91,254,451.87	91,254,451.87
20095627	01RX2CRP4 FLYASH RELIABILITY					5,917,294.84	84,861.60	48,422.19	100,105.90	70,784.62	27,489.21	27,782.95	120,531.50	6,397,272.81
20095628	01RX3CRP4 FLYASH RELIABILITY											8,814,129.76	708,086.73	9,522,216.49
20095629	01RX4CRP4 FLYASH RELIABILITY	5,887.34	3,766.00	169.70	9,154.13	95.65	92.37	5,595.29	96.01	105.32	91.74	(449.36)	621.90	25,226.09
CCASH137	CCP ASH-137 Potable Water Line Repl			416,823.22	4,391.16	2,856.74	2,249.01		2,018.29	0.99				428,339.41
CCMAY152	CCP MAY-149,-152 MFMV, P & VFD Inst											807,443.80	210.84	807,654.64
CHFL129C	CCP HFL-129 Pond Dam Spillwy Install		2,020,997.56	1,415.45										2,022,413.01
CRX000213	RX00 - Lined Retention Basin												22,853,630.47	22,853,630.47
Grand Total		**5,887.34**	**2,024,763.56**	**418,408.37**	**13,545.29**	**5,920,247.23**	**87,202.98**	**54,017.48**	**102,220.20**	**70,890.93**	**27,580.95**	**9,648,907.15**	**114,937,533.31**	**133,311,204.79**

FILED SENATE
May 14, 2014
S.B. 729
PRINCIPAL CLERK

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 152 of 168

GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2013

S D

SENATE DRS25122-TAa-16 (05/07)

Short Title:	Governor's Coal Ash Action Plan.	(Public)
Sponsors:	Senators Apodaca and Berger (Primary Sponsors).	
Referred to:		

A BILL TO BE ENTITLED

AN ACT TO (1) CHANGE NOTIFICATION REQUIREMENTS APPLICABLE TO DISCHARGES OF WASTEWATER; (2) ESTABLISH COAL COMBUSTION PRODUCTS IMPOUNDMENT WATER MONITORING PROGRAM; (3) IDENTIFY AND ADDRESS UNPERMITTED WASTEWATER DISCHARGES AT COAL COMBUSTION PRODUCTS IMPOUNDMENT SITES; (4) AMEND S.L. 2009-390; (5) REQUIRE EMERGENCY ACTION PLANS FOR HIGH AND INTERMEDIATE HAZARD DAMS; (6) CHANGE NOTIFICATION REQUIREMENTS APPLICABLE TO DAM REPAIRS; (7) INCREASE COAL COMBUSTION PRODUCTS IMPOUNDMENT INSPECTION REQUIREMENTS; (8) MODIFY THE DEFINITION OF SOLID WASTE TO INCLUDE REMOVED COMBUSTION PRODUCTS; (9) PLACE A TEMPORARY MORATORIUM ON THE USE OF COAL COMBUSTION PRODUCTS AS STRUCTURAL FILL; AND (10) ESTABLISH REQUIREMENTS FOR COAL COMBUSTION PRODUCTS IMPOUNDMENT CLOSURE.

Whereas, the issue of coal ash storage has not been adequately addressed in North Carolina for more than six decades; and

Whereas, on February 2, 2014, an estimated 39,000 tons of coal ash was released into the Dan River following the failure of a stormwater pipe under a utility coal ash impoundment pond in Eden, North Carolina; and

Whereas, the Department of Environment and Natural Resources ("Department") finds that coal combustion products have settled into the sediment of the river bottom and will require an extensive clean-up plan to complete remediation; and

Whereas, the Department is in the process of reassessing previous efforts at achieving compliance at coal ash facilities and developing short term and long term policies in light of the Dan River spill, violations discovered in light of increased inspections of coal combustion products disposal facilities and anticipated new federal regulations on coal combustion products; and

Whereas, it is the intent of the Department to ensure that spills of wastewater are reported to the Department in a defined and adequate time frame; and

Whereas, it is the intent of the Department to protect surface water and groundwater resources for their best usage; and

Whereas, it is the intent of the Department to ensure that all unpermitted wastewater discharges are eliminated or addressed in an environmentally responsible manner; and

DRS25122-TAA-16

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 153 of 168

Whereas, it is the intent of the Department to equally subject all dams under jurisdiction of G.S. 143-215.23 to the requirements of statute and administrative code; and

Whereas, it is the intent of the Department for the owners of all dams under jurisdiction of G.S. 143-215.23 deemed intermediate and high hazard by the Department to prepare at their own cost documents that describe full and adequate response to emergency situations at their dams and to submit those documents to the Department; and

Whereas, it is the intent of the Department to ensure that emergency situations at dams are reported to the Department in a defined and adequate time frame; and

Whereas, the it is the intent of the Department to increase oversight of dam structure integrity to protect the health and safety of the public; and

Whereas, state law exempts coal combustion products removed from impoundments from being defined as a solid waste; and

Whereas, the Department finds that consistent environmental standards should apply to coal combustion products removed from impoundments for management or disposal and coal combustion products managed or disposed of as a solid waste; and

Whereas, the Department finds the federal Environmental Protection Agency is under consent decree to complete new regulations by December 2014 for coal combustion products that are proposed to bring consistency to requirements for large fills such as structural fills and landfills; and

Whereas, the Department finds that conversion and closure of coal ash storage ponds is necessary for protection of the health and safety of the public; Now, therefore,

The General Assembly of North Carolina enacts:

PART I. NOTIFICATION REQUIREMENTS APPLICABLE TO DISCHARGES OF WASTEWATER

SECTION 1. G.S. 143-215.1C reads as rewritten:

"**§ 143-215.1C. Report to wastewater system customers on system performance; report discharge of untreated wastewater and wastewater containing coal combustion products to the Department; publication of notice of discharge of untreated wastewater and waste.**

(a) Report to Wastewater System Customers. – The owner or operator of any wastewater collection or treatment works, the operation of which is primarily to collect or treat municipal or domestic wastewater and for which a permit is issued under this Part and having an average annual flow greater than 200,000 gallons per day, shall provide to the users or customers of the collection system or treatment works and to the Department an annual report that summarizes the performance of the collection system or treatment works and the extent to which the collection system or treatment works has violated the permit or federal or State laws, regulations, or rules related to the protection of water quality. The report shall be prepared on either a calendar or fiscal year basis and shall be provided no later than 60 days after the end of the calendar or fiscal year.

(a1) Report of Discharge of Untreated Wastewater or Wastewater Containing Coal Combustion Products to the Department. – The owner or operator of any wastewater collection or treatment works shall report a discharge of 1,000 gallons or more of untreated wastewater or wastewater containing coal combustion products, or a spill of any amount of untreated wastewater or wastewater containing coal combustion products that reaches waters of the State to the Department as soon as possible but not later than 24 hours after first knowledge of the spill. This reporting requirement shall be in addition to any other reporting requirement applicable to the owner or operator of the wastewater collection or treatment works.

(b) Publication of Notice of Discharge of Untreated Wastewater. – The owner or operator of any wastewater collection or treatment works, the operation of which is primarily to

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 154 of 168

collect or treat municipal or domestic wastewater ~~and for which a permit is issued under this Part~~ shall:

(1) In the event of a discharge of 1,000 gallons or more of untreated wastewater or wastewater containing coal combustion products to the surface waters of the State, issue a press release to all print and electronic news media that provide general coverage in the county where the discharge occurred setting out the details of the discharge. The owner or operator shall issue the press release within ~~48~~ 24 hours after the owner or operator has ~~determined that the discharge has reached the surface waters of the State.~~ first knowledge of the spill. The owner or operator shall retain a copy of the press release and a list of the news media to which it was distributed for at least one year after the discharge and shall provide a copy of the press release and the list of the news media to which it was distributed to any person upon request.

(2) In the event of a discharge of 15,000 gallons or more of untreated wastewater to the surface waters of the State, publish a notice of the discharge in a newspaper having general circulation in the county in which the discharge occurs and the county immediately downstream and in each county downstream from the point of discharge that is significantly affected by the discharge. The Secretary shall determine, at the Secretary's sole discretion, which counties are significantly affected by the discharge and shall approve the form and content of the notice and the newspapers in which the notice is to be published. The notice shall be captioned "NOTICE OF DISCHARGE OF UNTREATED SEWAGE". The owner or operator shall publish the notice within 10 days after the Secretary has determined the counties that are significantly affected by the discharge and approved the form and content of the notice and the newspapers in which the notice is to be published. The owner or operator shall file a copy of the notice and proof of publication with the Department within 30 days after the notice is published. Publication of a notice of discharge under this subdivision is in addition to the requirement to issue a press release under subdivision (1) of this subsection.

(c) Publication of Notice of Discharge of Untreated Waste as defined in G.S. 143-213(18). – The owner or operator of any wastewater collection or treatment works, other than a wastewater collection or treatment works the operation of which is primarily to collect or treat municipal or domestic ~~wastewater, for which a permit is issued under this Part~~ wastewater shall:

(1) In the event of a discharge of 1,000 gallons or more of untreated waste to the surface waters of the State, issue a press release to all print and electronic news media that provide general coverage in the county where the discharge occurred setting out the details of the discharge. The owner or operator shall issue the press release within ~~48~~ 24 hours after the owner or operator has ~~determined that the discharge has reached the surface waters of the State.~~ first knowledge of the spill. The owner or operator shall retain a copy of the press release and a list of the news media to which it was distributed for at least one year after the discharge and shall provide a copy of the press release and the list of the news media to which it was distributed to any person upon request.

(2) In the event of a discharge of 15,000 gallons or more of untreated waste to the surface waters of the State, publish a notice of the discharge in a newspaper having general circulation in the county in which the discharge occurs and the county immediately downstream and in each county

downstream from the point of discharge that is significantly affected by the discharge. The Secretary shall determine, at the Secretary's sole discretion, which counties are significantly affected by the discharge and shall approve the form and content of the notice and the newspapers in which the notice is to be published. The notice shall be captioned "NOTICE OF DISCHARGE OF UNTREATED WASTE". The owner or operator shall publish the notice within 10 days after the Secretary has determined the counties that are significantly affected by the discharge and approved the form and content of the notice and the newspapers in which the notice is to be published. The owner or operator shall file a copy of the notice and proof of publication with the Department within 30 days after the notice is published. Publication of a notice of discharge under this subdivision is in addition to the requirement to issue a press release under subdivision (1) of this subsection."

PART II. COAL COMBUSTION PRODUCTS IMPOUNDMENT WATER MONITORING PROGRAM

SECTION 2. Article 21 of Chapter 143 of the General Statutes is amended by adding a new section to read:

"**§ 143-215.1D. Coal combustion products impoundment water monitoring program.**

(a) Groundwater Assessment – Owners of coal ash impoundments located at all investor-owned public utilities shall conduct groundwater monitoring according to the following schedule and procedures:

(1) No later than 45 days from enactment of this Act, the owner shall submit to the Division of Water Resources a Plan of proposed assessment activities to evaluate groundwater impacts from all coal combustions products impoundments located at all investor owned public utilities. At a minimum the plan shall:

a. Identify all receptors and significant exposure pathways.

b. Assess horizontal and vertical extent of soil and groundwater contamination for all contaminants confirmed to be present in groundwater in exceedance of groundwater quality standards and all significant factors affecting contaminant transport.

c. Identify the geological and hydrogeological features influencing the movement, chemical, and physical character of the contaminants.

d. Propose a schedule for continued groundwater monitoring.

Upon review and approval by the Division of Water Resources, the investor-owned public utility shall initiate assessment activities.

(2) No later than 180 days from the Division of Water Resources' written approval of the Plan required under subdivision (1) of subsection (a) of this section, or a time frame otherwise approved by the Division of Water Resources, the owner shall submit a Report detailing the findings of the Plan. The Report shall set forth the extent of any and all exceedances of the groundwater quality standards.

(3) No later than 270 days from the Division of Water Resources' written approval of the Plan required under subdivision (1) of subsection (a) of this section, or a time frame otherwise approved by the Division of Water Resources, the owner shall submit to the Division of Water Resources a proposed Corrective Action Plan. The Corrective Action Plan shall, at a minimum, contain:

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 155 of 168

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 156 of 168

a. A listing of all exceedances of the groundwater quality standards including any exceedances that the owner asserts are the result of natural background conditions.

b. Except as provided in subsubdivision f. of this subdivision, a description of the proposed corrective action employing the best available technology for the restoration of groundwater quality to the level of the groundwater quality standards and reasons for its selection.

c. Specific plans, including engineering details where applicable, for restoring groundwater quality.

d. A schedule for the implementation of the proposed corrective action plan.

e. A monitoring plan for evaluating the effectiveness of the proposed corrective action and the movement of the contaminant plume.

f. The owner may request alternative remediation as provided for under the requirements of 15A NCAC 2L .0106 (k), (l), or (m).

(4) No later than 30 days from the Division of Water Resources' approval of a Final Corrective Action Plan, the owner shall implement the Final Corrective Action Plan in accordance with a schedule established by Division of Water Resources. The approval of a Final Corrective Action Plan is not a final agency action pursuant to G.S. 150B.

(b) Drinking Water Assessment. – Within 60 days of enactment of this Act, owners of coal ash impoundments located at all investor-owned public utilities shall conduct and submit to the Division of Water Resources a water supply receptor survey. The Survey shall identify all receptors within a radius of 2,640 feet (0.5 mile) from the established compliance boundary of each impoundment. The owner shall sample each receptor identified by the Division of Water Resources. For any well exceeding the groundwater standards, the owner shall replace the water supply with a supply of potable drinking water.

(c) Annual Reporting Requirement. – In addition to any other reports required by the Division of Water Resources, the owners of coal combustion products impoundments located at all investor owned public utilities shall submit an annual report to the Division of Water Resources no later than January 31 of each year. The Annual report shall include a summary of all monitoring data collected over the year, status of Plans and Final Corrective Action Plans, and a summary of water supply receptor survey results."

PART III. IDENTIFY AND ADDRESS UNPERMITTED WASTEWATER DISCHARGES AT COAL COMBUSTION PRODUCTS IMPOUNDMENT SITES

SECTION 3. Article 21 of Chapter 143 of the General Statutes is amended by adding a new section to read:

"**§ 143-215.1E. Identify and address unpermitted wastewater discharges at coal combustion products impoundment sites.**

(a) Owners of coal combustion products impoundments located at all investor-owned public utilities shall implement the plan described in subsections (b) through (h) of this section to identify and address any unpermitted discharges to surface waters at those coal combustion products impoundment sites.

(b) No later than 90 days from enactment of this act, the owner shall submit a topographic map at a scale approved by Division of Water Resources that indicates the locations of all outfalls from engineered channels designed and/or improved for the purpose of collecting water from the toe of the coal combustion products impoundments. For each outfall, the map will:

(1) Specify its latitude and longitude.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 157 of 168

(2) Specify whether the discharge is continuous or intermittent.
(3) Provide an average flow measurement, including a description of the method used to measure flow.

With the topographic map, the owner will submit to the Division of Water Resources a schedule according to which the owner shall conduct water quality sampling of the toe drain outfalls in order to further characterize the discharging water. No later than 30 days from receipt of the map and sampling schedule, Division of Water Resources will provide the owner with review comments, either approving the plan or noting any deficiencies to be corrected and a date by which a corrected map and/or sampling schedule is to be submitted for further review and comment. Within 30 days of approval of the schedule by the Division of Water Resources, the owner shall begin to sample the toe drain outfalls in accordance with the schedule and submit the samples for water quality analysis. Water quality analyses shall include the same parameters required for a coal-fired power plant per EPA Application Form 2C – Wastewater Discharge Information, Consolidated Permits Program (EPA Form 3510-2C, August 1990). If the owner demonstrates to the satisfaction of Division of Water Resources that sampling of a toe drain outfall is unlikely to generate usable data or is otherwise infeasible, the owner will not be required to sample that toe drain outfall.

(c) No later than 180 days from the enactment of this act, the owner shall submit a topographic map at a scale approved by the Division of Water Resources that indicates the locations of any seeps or drains reflecting discharges from the ash ponds but are not captured by an engineered channel identified pursuant to subsection (b) of this section. For any seep so identified that is believed to not reflect flows from any of the ash ponds, the owner shall provide to the Division of Water Resources the basis for such belief, including hydrological data or water quality testing information. For the seeps from the impoundments, the map will:

(1) Specify its latitude and longitude.
(2) Specify whether the discharge is continuous or intermittent.
(3) Provide an average flow measurement, including a description of the method used to measure flow.
(4) Specify whether the discharge from the seep reaches surface waters.
(5) If the discharge from the seep reaches surface water, identify the location where the seep reaches surface water on the map to include latitude and longitude.

(d) No later than 180 days from the enactment of this act, the owner shall submit a plan to determine whether toe drain or seep discharges from the impoundments have reached surface waters of the state and are causing violations of surface water quality standards. The plan shall include the following:

(1) Sampling locations upstream and downstream within all channels that potentially carry such discharges.
(2) Water quality analyses shall include the same parameters required for a coal-fired power plant per EPA Application Form 2C – Wastewater Discharge Information, Consolidated Permits Program (EPA Form 3510-2C, August 1990).
(3) Frequency and duration of the sampling activities.
(4) Reporting requirements.

No later than 30 days from receipt of the plan, the Division of Water Resources will provide the owner with review comments, either approving the plan, or noting any deficiencies to be corrected and a date by which a corrected plan is to be submitted for further review and comment or approval. Within 180 days from the Division of Water Resources' approval of the plan, the owner will implement and complete the plan and submit a report summarizing that work and its results.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 158 of 168

(e) If the Division of Water Resources determines, based on information submitted pursuant to subsections (b) through (d) of this section, that discharges, whether from toe drains or seeps, are causing a violation of G.S. 143-215.1 or any other law, it shall so notify the owner. Within 120 days of such notification, the owner shall do one of the following:

(1) Stop the discharge.

(2) Capture and route the discharge so that it is discharged through an NPDES permitted outfall.

(3) Address the seep using Best Management Practices approved by the Division of Water Resources pursuant to subsection (f) of this section.

(4) Propose alternative Best Management Practices subject to the approval of the Division of Water Resources.

(5) Apply for an NPDES discharge permit or permit amendment to regulate the discharge.

(f) No later than 180 days from the date of enactment of this act, The owner shall submit to the Division of Water Resources for approval a set of best management practices designed to prevent unpermitted discharges of pollutants from the ash ponds to surface waters. Thereafter, the owner may submit additional best management practices for the Division of Water Resources approval.

(g) No later than 30 days from enactment of this act, the owner shall submit to the Division of Water Resources a plan for identifying new seeps on the dike areas of the ash ponds that arise after the submission of the maps described in subsections (b) and (c) of this section. The plan shall include, at a minimum, the following elements:

(1) A procedure for routine inspection of the coal combustion products impoundment areas to identify indicators of potential new seeps.

(2) A decision flow chart (including criteria and procedures) for determining whether a new seep is actually present.

(3) A procedure for notifying the Division of Water Resources after a new seep is confirmed.

No later than 30 days from receipt of the plan, the Division of Water Resources will provide the owner with review comments noting any deficiencies.

(h) No later than 12 months from the enactment of this act, the owner shall submit any information, forms, and fees necessary to request that the Division of Water Resources incorporate the process described in subsections (b) through (g) of this section into the owner's NPDES permit."

PART IV. AMEND S.L. 2009-390 (SB 1004)

SECTION 4. Section 3.(b) of S.L. 2009-390 is repealed.

PART V. EMERGENCY ACTION PLANS

SECTION 5. G.S. 143-215.31 is amended by adding two subsections to read:

"**§ 143-215.31. Supervision over maintenance and operation of dams.**

...

(f) Develop Emergency Action Plan. – Owners of high and intermediate hazard dams shall develop at their cost an Emergency Action Plan for their dam in document format in triplicate copy to be submitted to the Department by January 1, 2015. The emergency action plan at minimum shall:

(1) Identify potential emergency conditions that can occur at the dam.

(2) List preplanned actions to be taken during an emergency condition at the dam.

(3) Document emergency notification procedures to aid in warning and evacuations during an emergency condition at the dam.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 159 of 168

(4) Provide a downstream inundation map depicting areas affected by a dam failure and sudden release of the impoundment.

If a dam owner fails to provide the Department with an Emergency Action Plan in triplicate copy by January 1, 2015, it shall be subject to Enforcement Procedures under G.S. 143-215.36. Dam owners shall update their emergency action plans annually and submit the updated plans in triplicate copy to the Department each year subsequent to January 1, 2015. The Department shall provide the appropriate local Emergency Management Agency and the Regional Office of the Department with the triplicate copy.

(g) Confidentiality of Sensitive Public Security Information – To the extent that any documents included in the Emergency Action Plan developed under this section contain sensitive public security information, those portions of documents shall not be subject to disclosure under the North Carolina Public Records Act."

PART VI. NOTIFICATION OF EMERGENCY REPAIR OF A DAM

SECTION 6. G.S. 143-215.27 reads as rewritten:

"**§143-215.27. Repair, alteration, or removal of dam.**

(a) Before commencing the repair, alteration or removal of a dam, application shall be made for written approval by the Department, except as otherwise provided by this Part. The application shall state the name and address of the applicant, shall adequately detail the changes it proposes to effect and shall be accompanied by maps, plans and specifications setting forth such details and dimensions as the Department requires. The Department may waive any such requirements. The application shall give such other information concerning the dam and reservoir required by the Department, such information concerning the safety of any change as it may require, and shall state the proposed time of commencement and completion of the work. When an application has been completed it may be referred by the Department for agency review and report, as provided by subsection (b) of G.S. 143-215.26 in the case of original construction.

(b) When repairs are necessary to safeguard life and property they may be started immediately but the Department shall be notified ~~forthwith~~ of the proposed repairs and of the work under ~~way,~~way as soon as possible but not later than 24 hours after first knowledge of the necessity for emergency repairs, and ~~they~~ such repairs shall be made to conform to its orders."

PART VII. INSPECTION OF IMPOUNDMENTS

SECTION 7. G.S. 143-215.32 is amended by adding two sections to read:

"(e) Investor-owned public utilities shall inspect each coal combustion products impoundment weekly and after storms to detect evidence of any of the following:

(1) Deterioration, malfunctions, or improper operation of spillway control systems.

(2) Sudden drops in the level of the impoundment's contents.

(3) Severe erosion or other signs of deterioration in dikes or other containment devices.

(4) New or enlarged seeps along the downstream slope or toe of the dike or other containment devices.

(5) Any other abnormal conditions at the impoundment that may pose a health or safety risk.

If any abnormalities in subdivisions (1) through (5) of this subsection are observed, documentation shall be provided to a registered professional engineer for further investigation and appropriate action.

(f) Each coal combustion products impoundment located at investor-owned public utilities shall be inspected annually by an independent registered professional engineer to assure structural integrity and that the design, operation, and maintenance of the surface

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 160 of 168

impoundment are in accordance with generally accepted engineering standards. The owner or operator must notify the Department by way of a certification by the independent registered professional engineer that the dam is structurally sound and the design, operation, and maintenance of the surface impoundment is in accordance with generally accepted engineering standards. The inspection report shall be submitted to the Department within 30 days of the completion of the inspection and shall be placed on a publicly accessible internet site."

PART VIII. DEFINITION OF SOLID WASTE

SECTION 8.(a) G.S. 130A-290(a)(35) reads as rewritten:

"(35) "Solid waste" means any hazardous or nonhazardous garbage, refuse or sludge from a waste treatment plant, water supply treatment plant or air pollution control facility, domestic sewage and sludges generated by the treatment thereof in sanitary sewage collection, treatment and disposal systems, and other material that is either discarded or is being accumulated, stored or treated prior to being discarded, or has served its original intended use and is generally discarded, including solid, liquid, semisolid or contained gaseous material resulting from industrial, institutional, commercial and agricultural operations, and from community activities. The term does not include:

a. Fecal waste from fowls and animals other than humans.

b. Solid or dissolved material in:

1. Domestic sewage and sludges generated by treatment thereof in sanitary sewage collection, treatment and disposal systems which are designed to discharge effluents to the surface waters.

2. Irrigation return flows.

3. Wastewater discharges and the sludges incidental to and generated by treatment which are point sources subject to permits granted under Section 402 of the Water Pollution Control Act, as amended (P.L. 92-500), and permits granted under G.S. 143-215.1 by the Environmental Management Commission. However, ~~any~~ combustion products removed from impoundments subject to permits under Section 402 of the Water Pollution Control Act, as amended (P.L. 92-500), and permits granted under G.S. 143-215.1 by the Environmental Management Commission shall be a solid waste. Any sludges that meet the criteria for hazardous waste under RCRA shall also be a solid waste for the purposes of this Article.

c. Oils and other liquid hydrocarbons controlled under Article 21A of Chapter 143 of the General Statutes. However, any oils or other liquid hydrocarbons that meet the criteria for hazardous waste under RCRA shall also be a solid waste for the purposes of this Article.

d. Any source, special nuclear or byproduct material as defined by the Atomic Energy Act of 1954, as amended (42 U.S.C. § 2011).

e. Mining refuse covered by the North Carolina Mining Act, G.S. 74-46 through 74-68 and regulated by the North Carolina Mining and Energy Commission (as defined under G.S. 143B-293.1). However, any specific mining waste that meets the criteria for hazardous waste under RCRA shall also be a solid waste for the purposes of this Article.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 161 of 168

f. Recovered material."

SECTION 8.(b) G.S. 143-213(18) reads as rewritten:

"(18) "Waste" shall mean and include the ~~following:~~following with the exception of solid waste as defined by G.S. 130A-290(a)(35):

a. "Sewage," which shall mean water-carried human waste discharged, transmitted, and collected from residences, buildings, industrial establishments, or other places into a unified sewerage system or an arrangement for sewage disposal or a group of such sewerage arrangements or systems, together with such ground, surface, storm, or other water as may be present.

b. "Industrial waste" shall mean any liquid, solid, gaseous, or other waste substance or a combination thereof resulting from any process of industry, manufacture, trade or business, or from the development of any natural resource.

c. "Other waste" means sawdust, shavings, lime, refuse, offal, oil, tar chemicals, dissolved and suspended solids, sediment, and all other substances, except industrial waste, sewage, and toxic chemicals which may be discharged into or placed in such proximity to the water that drainage therefrom may reach the water.

d. "Toxic waste" means that waste, or combinations of wastes, including disease-causing agents, which after discharge and upon exposure, ingestion, inhalation, or assimilation into any organism, either directly from the environment or indirectly by ingestion through food chains, will cause death, disease, behavioral abnormalities, cancer, genetic mutations, physiological malfunctions (including malfunctions in reproduction) or physical deformities, in such organisms or their offspring."

PART IX. TEMPORARY MORATORIUM ON STRUCTURAL FILL

SECTION 9.(a) Moratorium Established. – Notwithstanding rules adopted by the Commission for Public Health there is hereby established a moratorium on the use of coal combustion products as a structural fill unless the fill is used under an airport runway or base or sub-base of a concrete or asphalt paved road, constructed under the authority of a public entity. The moratorium established by this section shall be in effect until rules are amended by the Commission for Public Health for the management of coal combustion products.

SECTION 9.(b) For purposes of this section, the moratorium does not apply to structural fill sites of less than 5,000 cubic yards.

SECTION 9.(c) This section is effective when this act becomes law and applies only to those coal combustion products structural fills that have not begun construction or have not received a permit to begin construction on or before that date.

PART X. COAL COMBUSTION PRODUCTS IMPOUNDMENT CLOSURE

SECTION 10.(a) Article 21 of Chapter 143 of the General Statutes is amended by adding a new Part to read:

"Part 12. Coal Combustion Products Impoundment Closure

"**§ 143-215.74Q. Closure of Coal Combustion Products Impoundments to Protect Groundwater and Surface Water**

(a) The Department shall establish the priority for closure of all active and inactive investor-owned coal combustion products impoundments. Once priorities for closure are established, the owner of the active and inactive ash ponds shall propose a schedule for beginning closure activities for each prioritized facility, and shall submit a proposed schedule

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 162 of 168

in accordance with the time frame established by the Department. Six months (180 days) before the scheduled closure activities begin, the owner must submit five (5) paper copies and one (1) electronic copy of a closure plan to the Division of Water Resources for approval. The closure plan shall include the following sections:

(1) Facility and Ash Pond Description. – A description of the operation of the facility that shall include, but not be limited to:
- a. Site and history of site operations; ash handling and storage operations.
- b. Types of flows discharging into the impoundment.
- c. Estimated volume of material contained in the impoundment.
- d. Analysis of the structural integrity of dikes or dams associated with impoundment.
- e. Composition of liner (lined or unlined pond).
- f. Summarized results of any previous environmental investigations performed at the site.

(2) Site Map. – Site maps that illustrate the following:
- a. All structures associated with operations of the ash ponds within the power plant property boundary.
- b. All identified current and former ash disposal and storage areas including structural fills.
- c. All property boundaries and established compliance boundaries.
- d. All potential receptors (i.e. water supply wells, surface water bodies (streams, springs, lakes, ponds and other surface drainage features, and wetlands) within 2,640 feet from the compliance boundary.
- e. Topographic contour intervals of the site shall be selected to enable an accurate representation of site features and terrain and in most cases should be less than 20 feet intervals.
- f. Locations of all on-site active and inactive Division of Waste Management permitted solid waste facilities along with their associated compliance boundaries and monitoring wells.
- g. All existing and proposed groundwater monitoring wells associated with monitoring of the active and inactive ash ponds.
- h. All existing and proposed sample collection locations associated with the operation or closure of the impoundment(s).

(3) Hydrogeologic, Geologic, and Geotechnical Investigations. – The results of a hydrogeologic, geologic, and geotechnical investigation of the facility, that shall include, but not be limited to:
- a. A description of the hydrogeology and geology of the site.
- b. A description of the stratigraphy of the geologic units underlying the ash ponds.
- c. The saturated hydraulic conductivity for the ash and liner if present.
- d. The geotechnical properties for the ash, liner if present, and the uppermost identified stratigraphic unit underlying the impoundment including the soil classification by Unified Soil Classification System, in-place moisture content, particle size distribution, Atterberg limits, specific gravity, effective friction angle, maximum dry density, optimum moisture content, and permeability.
- e. A chemical analysis of the impoundment water, ash, and ash-affected soil. Identify constituents with concentrations found to be in excess of 15A NCAC 02L. 0202 Groundwater Quality Standards including all laboratory results for these analyses.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 163 of 168

f. Summary tables of historical records of groundwater sampling results.

g. A map that illustrates the potentiometric contours and flow directions for all identified aquifers underlying impoundments (shallow, intermediate, and deep) and the horizontal extent of areas where 15A NCAC 02L .0202 Groundwater Quality Standards are exceeded.

h. Cross-sections that illustrate the following: vertical and horizontal extent of the ash within the impoundment; Stratigraphy of the geologic units underlying the ash pond and the vertical extent of areas where 15A NCAC 02L .0202 Groundwater Quality Standards are exceeded.

(4) Hydrogeologic Modeling. – The results of groundwater modeling of the site that shall include, but not be limited to:

a. An account of the design of the proposed pond closure method that: is based on the site hydrogeologic conceptual model developed, includes predictions on post-closure groundwater elevations, groundwater flow directions and velocities including the effects on/from the potential receptors, and includes predictions at the compliance boundary for constituents identified in subsubdivision e. of subdivision (3) of this subsection as exceeding 15A NCAC 2L .0202 Groundwater Quality Standards.

b. Predictions that include the effects on the groundwater chemistry, and should describe migration, concentration, mobilization and fate of the constituents that exceed 15A NCAC 2L standards before and after closure activities including the effects on/from potential receptors.

c. A description of the groundwater trend analysis methods used to demonstrate compliance with 15A NCAC 02L .0202 Groundwater Quality Standards and 15A NCAC 02L .0106.

(5) Closure Method. – The owner shall provide a proposed closure method. The proposed closure method must demonstrate that where groundwater quality is degraded, restoration to the level of the groundwater standards will be obtained as is economically and technically feasible. The selected proposed closure method shall be from one of the following alternatives, and shall include, but not be limited to:

a. A description of the closure method identified for each ash pond. Closure methods include:

i. Closure-in-Place. – This alternative entails placing an engineered cover system such as a composite geomembrane, impermeable clay, and/or a soil cover over the ash pond. No ash or ash-affected soil would leave the ash pond area.

ii. Clean Closure. – This alternative assumes that all coal ash can be excavated and the ash pond area will be returned to a non-erosive and stable condition.

iii. Hybrid Closure. – This alternative entails consolidating ash and ash-affected soil into as small area as feasible within the ash pond footprint. An engineered cover system (e.g. composite geomembrane, impermeable clay, and/or a soil cover) would be installed over the consolidated ash and ash-affected soil. The remaining ash pond area will be returned to a non-erosive and stable condition.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 164 of 168

iv. Other. – Must be equally or more effective at protecting water quality than the other closure options.

b. A description concerning any plans for beneficial reuse of the coal ash under 15A NCAC 02T .1200 (if applicable).

c. All engineering drawings, schematics, and specifications for the proposed closure method. If required by G.S. 89C, engineering design documents should be prepared, signed, and sealed by a professional engineer. Describe the construction quality assurance and quality control program including the responsibilities and authorities; monitoring and testing activities; sampling strategies; and reporting requirements.

d. A description of the provisions for disposal of wastewater through an NPDES permit or any other relevant permit.

e. A description of the provisions for the final disposition of the ash. If the ash is to be removed, the owner must identify the site location and the permit number for ash sent to a permitted disposal site. If the ash is left in place, the owner must provide a description of how the ash will be stabilized during closure and post closure and an estimate of the volume of ash left in place.

f. A list of all permits that will need to be acquired or modified to complete closure activities.

(6) Post-Closure Plan. – The owner shall provide post-closure plans for a minimum of 30 years. If required by G.S. 89C, these plans should be signed and sealed by a professional engineer. These plans shall include, but not be limited to:

a. A description of the post-closure care and maintenance activities.

b. A demonstration of the long-term control of all leachate, affected groundwater, and stormwater.

c. A description of a groundwater monitoring program that includes:

i. Post closure groundwater monitoring, including parameters to be sampled and sampling schedules.

ii. Any additional monitoring well installations, including a map with the proposed location/s and well construction details.

iii. A description of the actions proposed to mitigate statistically significant increasing groundwater quality trends.

d. The length of the post-closure care period. This period may be proposed to be decreased or the frequency and parameter list modified if the owner demonstrates that the reduced period or modifications are sufficient to protect human health and the environment and this demonstration is approved by the Department. The length of the post-closure care period may be increased by the Department at the end of the post-closure period if there are statistically significant increasing groundwater quality trends or contaminant concentrations have not decreased to a level protective of human health and the environment. If the owner determines that the post-closure care period is no longer needed and the Department agrees, the owner shall provide a certification, signed by a registered professional engineer, verifying that post-closure care has been completed in accordance with the post-closure plan.

(7) Schedules. – The owner shall provide an estimate of the milestone dates for all activities related to closure and post-closure.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 165 of 168

(8) Future Site Use. – The owner shall describe the anticipated future use of the site and the necessity for deed restrictions following closure.

(9) Final Submittal Determination and Approval. – Within 90 days of receipt of a completed closure plan, the Department will send a letter either approving the closure plan or requesting additional information. Upon approval, the owner must begin closure activities within 30 days."

SECTION 10.(b) Part 3 of Article 21 of Chapter 143 of the General Statutes is amended by adding a new section to read:

"**§ 143-215.37A. Closure of coal combustion products impoundments to render such facilities exempt from the North Carolina Dam Safety Law of 1967.**

(a) Decommissioning Request Submittal. – Any party seeking to decommission a coal combustion products impoundment facility shall submit a document from the ownership entity requesting that the facility be decommissioned to the Division of Energy, Mineral, and Land Resources. The document shall include as a minimum the following:

(1) A proposed geotechnical investigation plan scope of work. Upon preliminary plan approval as described below, the owner shall proceed with necessary field work and submit a geotechnical report with site specific field data indicating that the containment dam and material impounded by the containment dam are stable, and that the impounded material is not subject to liquid flow behavior under expected static and dynamic loading conditions. Material testing should be performed along the full extent of the containment dam and in a pattern throughout the area of impounded material.

(2) A topographic map depicting existing conditions of the containment dam and impoundment area at two foot contour intervals or less.

(3) If the facility contains areas capable of impounding by topography, a breach plan must be included which ensures that there shall be no place within the facility capable of impounding. The breach plan shall include at minimum proposed grading contours superimposed on the existing topographic map as well as necessary engineering calculations, construction details and construction specifications.

(4) A permanent vegetation and stabilization or capping plan by synthetic liner or other means if needed. These plans shall include at minimum, proposed grading contours superimposed on the existing topographic map where applicable as well as necessary engineering calculations, construction details, construction specifications and all details for the establishment of surface area stabilization.

(5) A statement indicating that the impoundment facility has not received sluiced coal ash material for at least three years and there are no future plans to place coal ash in the facility by sluicing methods.

(b) Preliminary Submittal Determination and Approval. – The submitted document shall undergo a preliminary review by the Division of Energy, Mineral, and Land Resources for completeness and approval of the proposed geotechnical investigation plan scope of work.

(1) The owner shall be notified by letter with results of the preliminary review including approval or revision request relative to the proposed scope of work included in the geotechnical investigation plan.

(2) Upon receipt of a letter issued by the Division approving the preliminary geotechnical plan scope of work, the owner may proceed with field work and development of the geotechnical report.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 166 of 168

(c) Final Submittal Determination and Approval. – Upon receipt of the geotechnical report, the Division of Energy, Mineral, and Land Resources shall complete the submittal review.

(1) If it is determined that sufficient evidence has been presented to clearly show that the facility no longer functions as a dam in its current state, a letter decommissioning the facility shall be issued by the Division of Energy, Mineral, and Land Resources and the facility shall no longer be under jurisdiction of the Dam Safety Law of 1967, G.S. 143-215.23.

(2) If modifications such as breach construction and/or implementation of a permanent vegetation or surface lining plan are needed, such plans shall be reviewed per standard procedures for consideration of letter of approval to modify and/or breach.

(3) If approved, such plans shall follow standard procedure for construction including: construction supervision by a North Carolina registered professional engineer, as-built submittal by a North Carolina registered professional engineer, and follow up final inspection by Division of Energy, Mineral, and Land Resources staff.

(4) Final approval shall be issued by the Division of Energy, Mineral, and Land Resources in the form of a letter decommissioning the facility and the facility shall no longer be under jurisdiction of the Dam Safety Law of 1967, G.S. 143-215.23."

PART XI. CLOSURE PLANS SCHEDULE

SECTION 11. Notwithstanding G.S. 143-215.74Q and G.S. 143-215.37A as enacted by Sections 10.(a) and 10.(b) of this act:

(a) The closure plan for Riverbend shall be submitted to the Department no later than 60 days after the Act is ratified and shall include detailed provisions that ensure all ash in the impoundments will be moved to a lined structural fill, a lined landfill, or an alternative disposition approved by Department.

(b) The closure plan for Asheville shall be submitted to the Department no later than 60 days after the Act is ratified and include detailed provisions that ensure all ash in the impoundments will be moved to a lined structural fill, a lined landfill, or an alternative disposition approved by the Department.

(c) The closure plan for Dan River shall be submitted to the Department no later than 90 days after the Act is ratified and include detailed provisions that ensure all ash in the impoundments will be moved to a lined structural fill, a lined landfill, or an alternative disposition approved by the Department.

(d) The closure plan for Sutton shall be submitted to the Department no later than 90 days after the Act is ratified, and include detailed provisions that ensure all ash in the impoundments will be moved to a lined structural fill, a lined landfill, or an alternative disposition approved by Department.

PART XII. APPROPRIATION

SECTION 12. There is appropriated from the General Fund to the Department of Environment and Natural Resources the sum of one million four hundred thousand dollars ($1,400,000) for the 2013-2014 Fiscal Year to establish nineteen permanent positions and associated operating costs to implement this act."

PART XIII. EFFECTIVE DATE

SECTION 13. This act is effective when it becomes law.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 167 of 168

GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2015

S D

SENATE BILL 716
Commerce Committee Substitute Adopted 5/21/15
PROPOSED HOUSE COMMITTEE SUBSTITUTE S716-PCS45379-TD-36

Short Title: Mountain Energy Act of 2015. (Public)

Sponsors:

Referred to:

May 20, 2015

A BILL TO BE ENTITLED

AN ACT TO: (1) DIRECT THE NORTH CAROLINA UTILITIES COMMISSION TO RENDER AN EXPEDITED DECISION, UNDER CERTAIN CONDITIONS, ON AN APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR AN APPLICANT TO CONSTRUCT A GENERATING FACILITY THAT USES NATURAL GAS AS THE PRIMARY FUEL AND (2) MODIFY CERTAIN REQUIREMENTS UNDER THE COAL ASH MANAGEMENT ACT OF 2014 FOR COAL ASH SURFACE IMPOUNDMENTS LOCATED ON SITES AT WHICH ALL COAL-FIRED GENERATING UNITS PRESENT ON THOSE SITES WILL PERMANENTLY CEASE OPERATIONS BY JANUARY 31, 2020.

The General Assembly of North Carolina enacts:

SECTION 1. Notwithstanding G.S. 62-110.1, the Commission shall provide an expedited decision on an application for a certificate to construct a generating facility that uses natural gas as the primary fuel if the application meets the requirements of this section. A public utility shall provide written notice to the Commission of the date the utility intends to file an application under this section no less than 30 days prior to the submission of the application. When the public utility applies for a certificate as provided in this section, it shall submit to the Commission an estimate of the costs of construction of the gas-fired generating unit in such detail as the Commission may require. G.S. 62-110.1(e) and G.S. 62-82(a) shall not apply to a certificate applied for under this section. The Commission shall hold a single public hearing on the application applied for under this section and require the applicant to publish a single notice of the public hearing in a newspaper of general circulation in Buncombe County. The Commission shall render its decision on an application for a certificate, including any related transmission line located on the site of the new generation facility, within 45 days of the date the application is filed if all of the following apply:

(1) The application for a certificate is for a generating facility to be constructed at the site of the Asheville Steam Electric Generating Plant located in Buncombe County.

(2) The public utility will permanently cease operations of all coal-fired generating units at the site on or before the commercial operation of the generating unit that is the subject of the certificate application.

(3) The new natural gas-fired generating facility has no more than twice the generation capacity as the coal-fired generating units to be retired.

SECTION 2.(a) Section 3(b) of S.L. 2014-122 reads as rewritten:

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 168 of 168

"**SECTION 3.(b)** Notwithstanding G.S. 130A-309.211 or G.S. 130A-309.212, as enacted by Section 3(a) of this act, and except as otherwise preempted by the requirements of federal law, the following coal combustion residuals surface impoundments shall be deemed high-priority ~~and, as soon as practicable, but no later than August 1, 2019,~~ and shall be closed in conformance with Section 3(c) of this ~~act:~~act as follows:

(1) Coal combustion residuals surface impoundments located at the Dan River Steam Station, owned and operated by Duke Energy Progress, and located in Rockingham ~~County.~~County, as soon as practicable, but no later than August 1, 2019.

(2) Coal combustion residuals surface impoundments located at the Riverbend Steam Station, owned and operated by Duke Energy Carolinas, and located in Gaston ~~County.~~County, as soon as practicable, but no later than August 1, 2019.

(3) Coal combustion residuals surface impoundments located at the Asheville Steam Electric Generating Plant, owned and operated by Duke Energy Progress, and located in Buncombe ~~County.~~County, as soon as practicable, but no later than August 1, 2022.

(4) Coal combustion residuals surface impoundments located at the Sutton Plant, owned and operated by Duke Energy Progress, and located in New Hanover ~~County.~~County, as soon as practicable, but no later than August 1, 2019."

SECTION 2.(b) The requirements of subsections (c) through (f) of G.S. 130A-309.210 shall not apply to coal combustion residuals surface impoundments and electric generating facilities located at the Asheville Steam Electric Generating Plant in Buncombe County.

SECTION 2.(c) This section becomes effective August 1, 2016, if, on or before that date, the North Carolina Utilities Commission has issued a certificate of public convenience and necessity to Duke Energy Progress for a new natural gas-fired generating facility, pursuant to Section 1 of this act, based upon written notice submitted to the Commission from Duke Energy Progress that it will permanently cease operations of all coal-fired generating units at the Asheville Steam Electric Generating Plant located in Buncombe County no later than January 31, 2020.

SECTION 3. Except as otherwise provided, this act is effective when it becomes law.

United States
Environmental Protection
Agency

Office of Solid Waste
and Emergency Response
Washington, DC 20460

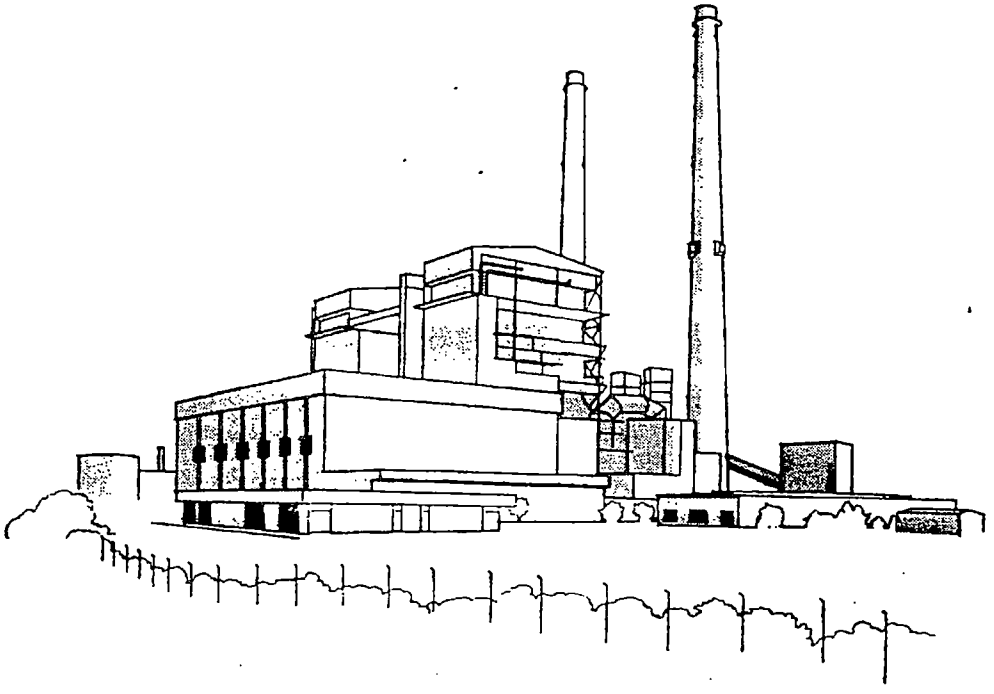
EPA/530-SW-88-002
February 1988

Solid Waste

EPA

Report to Congress

Wastes from the Combustion of Coal by Electric Utility Power Plants



ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 1 of 223

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 2 of 223

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 8 1988

THE ADMINISTRATOR

Honorable George Bush
President of the Senate
Washington, D.C. 20510

Dear Mr. President:

I am pleased to transmit the Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants. The report presents the results of studies carried out pursuant to Section 8002(n) of the Resource Conservation and Recovery Act of 1976 as amended (42 U.S.C. Section 6982(n)).

The report provides a comprehensive assessment of the management of solid wastes generated by the combustion of coal from electric utility power plants. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. The principal waste categories covered include fly ash, bottom ash, boiler slag and flue gas emission control waste.

The report and appendices are transmitted in two separate volumes.

Sincerely,

Lee M. Thomas

Enclosure

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 3 of 223

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 8 1988

THE ADMINISTRATOR

Honorable James C. Wright
Speaker of the House
of Representatives
Washington, D.C. 20515

Dear Mr. Speaker:

I am pleased to transmit the Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants. The report presents the results of studies carried out pursuant to Section 8002(n) of the Resource Conservation and Recovery Act of 1976 as amended (42 U.S.C. Section 6982(n)).

The report provides a comprehensive assessment of the management of solid wastes generated by the combustion of coal from electric utility power plants. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. The principal waste categories covered include fly ash, bottom ash, boiler slag and flue gas emission control waste.

The report and appendices are transmitted in two separate volumes.

Sincerely,

Lee M. Thomas

Enclosure

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 4 of 223

TABLE OF CONTENTS

		Page
EXECUTIVE SUMMARY		ES-1
I.	INTRODUCTION	1-1
	1.1 Legislative History	1-1
	1.2 Scope and Sources	1-7
	1.3 Organization	1-9
II.	OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY	2-1
	2.1 The Demand for Electricity	2-1
	2.1.1 Structure of the U.S. Electric Utility Industry	2-7
	2.1.2 Economic and Environmental Regulation of the Electric Utility Industry	2-11
	2.2 Importance of Coal to Electric Utilities	2-14
	2.3 Overview of Coal-Fired Power Plants	2-18
	2.3.1 Regional Characteristics of Coal-Fired Electric Generating Plants	2-18
	2.3.2 Electricity Generating Technologies	2-21
	2.4 Coal Constituents and By-Products	2-29
III.	WASTES GENERATED FROM COAL-FIRED ELECTRIC UTILITY POWER PLANTS	3-1
	3.1 Overview of Electric Utility Wastes	3-1
	3.2 High-Volume Wastes	3-3
	3.2.1 Ash	3-3
	3.2.2 FGD Sludge	3-21
	3.3 Low-Volume Wastes	3-41
	3.3.1 Boiler Blowdown	3-43
	3.3.2 Coal Pile Runoff	3-45
	3.3.3 Cooling Tower Blowdown	3-47
	3.3.4 Demineralizer Regenerant and Rinses	3-50
	3.3.5 Metal and Boiler Cleaning Wastes	3-52
	3.3.6 Pyrites	3-57
	3.3.7 Sump Effluents	3-60
	3.4 Summary	3-62
IV.	COAL COMBUSTION WASTE MANAGEMENT PRACTICES	4-1
	4.1 State Regulation of Coal Combustion Waste Disposal	4-1
	4.1.1 State Classification of Coal Combustion Wastes	4-2

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 5 of 223

TABLE OF CONTENTS (cont'd)

		Page
4.1.2	Requirements for Coal Combustion Waste Disposal	4-6
4.1.3	Summary	4-9
4.2	Available Waste Management Methods and Current Practices	4-10
4.2.1	Land Management of Coal Combustion Wastes	4-10
4.2.2	Alternative Waste Management Technologies	4-24
4.2.3	Ocean Disposal	4-44
4.2.4	Waste Utilization and Recovery of Various Waste By-Products	4-45
4.3	Summary	4-53
V.	POTENTIAL DANGERS TO HUMAN HEALTH AND THE ENVIRONMENT	5-1
5.1	RCRA Subtitle C Hazardous Waste Characteristics and Listing Criteria	5-2
5.1.1	Corrosivity of Coal Combustion Wastes	5-4
5.1.2	Extraction Procedure Toxicity of Coal Combustion Wastes	5-5
5.2	Effectiveness of Waste Containment at Utility Disposal Sites	5-28
5.2.1	ADL Study of Waste Disposal at Coal-Fired Power Plants	5-29
5.2.2	Franklin Associates Survey of State Ground-Water Data	5-44
5.2.3	Envirosphere Ground-Water Survey	5-48
5.2.4	Summary	5-52
5.3	Evidence of Damage	5-53
5.3.1	Envirosphere Case Study Analysis	5-54
5.3.2	Dames & Moore Study of Environmental Impacts	5-56
5.3.3	Case Studies of the Environmental Impact of Coal Combustion By-Product Waste Disposal	5-63
5.3.4	Summary	5-67
5.4	Factors Affecting Exposure and Risk at Coal Combustion Waste Sites	5-68
5.4.1	Environmental Characteristics of Coal Combustion Waste Sites	5-69
5.4.2	Population Characteristics of Coal Combustion Waste Disposal Sites	5-83
5.4.3	Ecologic Characteristics of Coal Combustion Waste Disposal Sites	5-89
5.4.4	Multivariate Analysis	5-93
5.5	Summary	5-95

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 6 of 223

TABLE OF CONTENTS (cont'd)

		Page
VI.	ECONOMIC COSTS AND IMPACTS	6-1
	6.1 Waste Disposal Costs Associated With Current Disposal Methods	6-2
	6.1.1 Costs of Waste Placement and Disposal	6-5
	6.1.2 Costs Associated with Lined Disposal Facilities	6-11
	6.2 Costs of Alternative Disposal Options	6-12
	6.2.1 Regulatory Alternatives Under Subtitle C	6-13
	6.2.2 Cost Estimates for Individual RCRA Subtitle C Disposal Standards	6-17
	6.2.3 Potential Costs to the Industry of RCRA Subtitle C Waste Management	6-30
	6.3 Impact of Regulatory Alternatives on Utilization of Coal Combustion Wastes	6-33
	6.4 Economic Impacts of Alternative Waste Disposal Options	6-37
	6.5 Summary	6-43
VII.	CONCLUSIONS AND RECOMMENDATIONS	7-1
	7.1 Scope of Report	7-1
	7.2 Summary of Report	7-2
	7.2.1 Location and Characteristics of Coal-Fired Power Plants	7-2
	7.2.2 Waste Quantities and Characteristics	7-3
	7.2.3 Waste Management Practices	7-5
	7.2.4 Potential Hazardous Characteristics	7-6
	7.2.5 Evidence of Environmental Transport of Potentially Hazardous Constituents	7-7
	7.2.6 Evidence of Damage	7-9
	7.2.7 Potential Costs of Regulation	7-9
	7.3 Recommendations	7-11

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 7 of 223

TABLE OF CONTENTS (cont'd)

		Page
Bibliography		
Glossary		
Appendix A:	Letter from Gary N. Dietrich, EPA, to Paul Emler, Jr., USWAG, January 13, 1981 and Memorandum from EPA Headquarters to EPA Regional Directors, February 18, 1981	A-1
Appendix B:	Methodology For Estimating Volume of Ash and FGD Sludge Generation	B-1
Appendix C:	Regulation of Coal Combustion Waste Disposal In Seventeen High Coal-Burning States	C-1
Appendix D:	Waste Fluid Studies	D-1
Appendix E:	Arthur D. Little Study of Waste Disposal At Coal-Fired Power Plants	E-1
Appendix F:	Data On Sample of Coal-Fired Combustion Waste Disposal Sites	F-1
Appendix G:	Methodology For Calculating The Cost of Alternative Waste Management Practices	G-1

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 8 of 223

INDEX OF EXHIBITS

Page

CHAPTER TWO

2-1 Growth in Electricity Demand - 1975-2000 2-2
2-2 Electricity Sales By Year and Class of Service 2-4
2-3 Electricity Demand by EPA Region: 1985 2-5
2-4 EPA Federal Regions 2-6
2-5 Generating Capacity in the United States 2-8
2-6 Electricity Generation by Primary Energy Source: 1975-2000 2-15
2-7 Electric Utility Dependence on Coal by EPA Region: 1985 2-17
2-8 U.S. Coal Consumption by Sector: 1975-2000 2-19
2-9 Total Number and Average Size of Coal-Fired Plants and Units 2-20
2-10 Range of Coal-Fired Power Plant Sizes 2-22
2-11 Process For Generating Electricity at Coal-Fired Power Plants 2-23
2-12 Diagram of a Pulverized Coal Boiler 2-25
2-13 Diagram of a Cyclone Boiler 2-27
2-14 Characteristics of Various Types of Stokers 2-30
2-15 Diagram of a Spreader Stoker 2-31
2-16 Total Coal Boiler Capacity by EPA Region 2-32
2-17 Average Coal Boiler Size By Type of Boiler and By EPA Region 2-33
2-18 Electric Utility Production of FGD Wastes: 1985 2-36

CHAPTER THREE

3-1 Representative Ash Contents By Producing Region and Coal Rank: 1985 3-9
3-2 Volume of Ash Generated by Coal-Fired Electric Utility Power Plants -- 1975-2000 3-10
3-3 Average Ash Content of Coal Burned by Electric Utility Power Plants in the U.S. -- 1975-2000 3-12
3-4 Representative Ranges of Values For the Physical Characteristics of Fly Ash, Bottom Ash, and Boiler Slag 3-14
3-5 Low and High Concentrations of Major Chemical Constituents Found in Ash Generated by Coal-Fired Power Plants 3-16
3-6 Element Concentrations In Ash From Three Geographic Sources 3-18
3-7 Effect Of Geographic Coal Source On Ash Element Concentration 3-19
3-8 Element Concentrations In Three Types Of Ash 3-20
3-9 Major Types of Flue Gas Desulfurization Systems 3-23
3-10 Flow Diagram of Wet Flue Gas Desulfurization System 3-25

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 9 of 223

INDEX OF EXHIBITS

Page

CHAPTER THREE (Continued)

3-11 Flow Diagram of Spray-Drying Flue Gas Desulfurization System 3-27
3-12 Flow Diagram of Dry Injection Flue Gas Desulfurization System 3-28
3-13 Flow Diagrams of Recovery Flue Gas Desulfurization Systems 3-30
3-14 FGD Capacity and FGD Sludge Generation -- 1970-2000 3-32
3-15 Representative Ranges of Values for the Physical Characteristics of FGD Sludge 3-36
3-16 Concentration of Major Chemical Constituents of Wet FGD Sludge Solids by Scrubber System and Source of Coal 3-39
3-17 Concentration of Major Chemical Constituents of Wet FGD Sludge Liquors by Scrubber System and Source of Coal 3-40
3-18 Concentration of Trace Elements Found in Wet-FGD Sludges 3-42
3-19 Annual Low-Volume Waste Generation At a Representative Coal-Fired Power Plant 3-44
3-20 Characteristics of Boiler Blowdown 3-46
3-21 Characteristics of Coal Pile Runoff 3-48
3-22 Characteristics of Cooling Tower Blowdown 3-51
3-23 Characteristics of Spent Demineralizer Regenerants 3-53
3-24 Reported Characteristics of Gas-Side Cleaning Wastes 3-55
3-25 Characteristics of Spent Water-Side Alkaline Cleaning Wastes 3-56
3-26 Characteristics of Spent Water-Side Hydrochloric Acid Cleaning Wastes 3-58
3-27 Characteristics of Spent Water-Side Alkaline Passivating Wastes 3-59
3-28 Characteristics of Pyrites and Pyrite Transport Water 3-61

CHAPTER FOUR

4-1 State Regulations Governing Coal Combustion Waste Disposal 4-3
4-2 Typical Surface Impoundment (Pond) Stages 4-12
4-3 Diagrams of Active and Closed Landfills 4-15
4-4 Utility Waste Management Facilities By EPA Region 4-19
4-5 Location of Utility Waste Management Facilities: On-site versus Off-site 4-21
4-6 Installation of Liners For Leachate Control at Utility Waste Management Facilities 4-31
4-7 Summary of Current Handling, Treatment and Disposal of Low-Volume Wastes 4-39

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 10 of 223

INDEX OF EXHIBITS

Page

CHAPTER FIVE

5-1 Maximum Concentration of Contaminants For Characteristic of EP Toxicity 5-6
5-2 Effect of Geographic Coal Source On Element Concentration In Ash 5-10
5-3 Results of Tetra Tech Extraction Tests On Coal Combustion Ash .. 5-12
5-4 Results of Arthur D. Little Testing Showing The Range of Concentration of Metals In EP Extracts 5-17
5-5 EP Toxicity Analysis For Untreated and Treated Boiler Chemical Cleaning Wastes 5-21
5-6 EP Toxicity Test Results For Liquid Low-Volume Wastes 5-23
5-7 Comparison of EP and TCLP Extractions For Low-Volume Sludge Dredged From Wastewater Ponds 5-24
5-8 EP Toxicity Test Results of Low-Volume Wastes Before and After Co-Disposal 5-26
5-9 Primary And Secondary Drinking Water Standards 5-30
5-10 Summary of Arthur D. Little's Ground-Water Quality Data On Primary Drinking Water Exceedances 5-35
5-11 Summary of Arthur D. Little's Ground-Water Quality Data on Secondary Drinking Water Exceedances 5-37
5-12 Summary of Arthur D. Little's Surface-Water Quality Data On Primary Drinking Water Exceedances 5-40
5-13 Summary of PDWS Exceedances in the Franklin Associates Survey 5-46
5-14 Summary of SDWS Exceedances in the Franklin Associates Survey 5-47
5-15 Summary of PDWS Exceedances in Envirosphere's Ground-water Data 5-50
5-16 Summary of SDWS Exceedances in Envirosphere's Ground-water Data 5-51
5-17 Distance Of Coal Combustion Waste Sites To Surface Water 5-72
5-18 Flow Of Nearest Surface-Water Body 5-74
5-19 Depth To Ground Water at Coal Combustion Waste Sites 5-77
5-20 Hydraulic Conductivity at Coal Combustion Waste Sites 5-78
5-21 Net Recharge at Coal Combustion Waste Sites 5-81
5-22 Ground-Water Hardness at Coal Combustion Waste Sites 5-82
5-23 Populations Within One Kilometer of Waste Sites 5-85
5-24 Populations Within Three Kilometers of Waste Sites 5-86
5-25 Populations Within Five Kilometers of Waste Sites 5-87
5-26 Populations Served By Public Water Systems Near Waste Sites 5-89
5-27 Ecological Status of Waste Sites 5-92

CHAPTER SIX

6-1 Overview of Waste Handling and Disposal Options for Coal Ash 6-3

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 11 of 223

INDEX OF EXHIBITS

		Page
CHAPTER SIX (Continued)		
6-2	Overview of Waste Handling and Disposal Options for FGD Waste	6-4
6-3	Ranges of Average Capital Costs Associated With Coal-Fired Electric Utility Waste Disposal	6-6
6-4	Ranges of Average Total Costs For Coal-Fired Electric Utility Waste Disposal	6-7
6-5	Summary of Costs to Close Existing Waste Disposal Facilities	6-23
6-6	Summary of Costs For Different Types of Lined Waste Management Facilities	6-28
6-7	Costs to the Electric Utility Industry For Hypothetical RCRA Compliance Strategies	6-29
6-8	Summary of Economic Impacts on By-Product Utilization Under Different RCRA Regulatory Scenarios	6-36
6-9	Impact of Current Waste Disposal Costs on Total Electricity Generation Costs	6-39
6-10	Impact of Alternative Disposal Options on Electricity Generation Costs	6-40

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 12 of 223

EXECUTIVE SUMMARY

The Environmental Protection Agency (EPA) has prepared this report on fossil fuel combustion wastes pursuant to the requirements of Section 8002(n) of the Resource Conservation and Recovery Act (RCRA), as amended in 1980. These amendments to the Act added Section 8002(n), which directed the Administrator of EPA to

> conduct a detailed and comprehensive study and submit a report on the adverse effects on human health and the environment, if any, of the disposal and utilization of fly ash waste, bottom ash waste, slag waste, flue gas emission control waste, and other by-product materials generated primarily from the combustion of coal or other fossil fuels.

Pending the completion of this study, fossil fuel combustion wastes were exempted from the hazardous waste requirements established under RCRA. Under Section 3001(b)(3)(A), EPA is prohibited from regulating these wastes until at least six months after this report is submitted to Congress.

If EPA determines that fossil fuel combustion wastes are hazardous under RCRA, and therefore subject to regulation under Subtitle C, EPA has some flexibility to promulgate regulations that take into account the unique characteristics of these wastes. Section 3004(x) states ...

> If ... fly ash waste, bottom ash waste, slag waste and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels ... is subject to regulation under this subtitle, the Administrator is authorized to modify the requirements of subsections (c), (d), (e), (f), (g), (o) and (u) and section 3005(j) ... to take into account the special characteristics of such wastes, the practical difficulties associated with implementation of such requirements, and site-specific characteristics ... so long as such modified requirements assure protection of human health and the environment.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 13 of 223

This report examines only those wastes generated from the combustion of coal by the electric utility industry. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. EPA has deferred study of the disposal of wastes generated by the combustion of other fossil fuels and from coal combustion in industries other than the electric utility industry until a later date.

Coal-fired power plants produce substantial quantities of wastes. In 1984 about 69 million tons of ash and 16 million tons of flue gas desulfurization wastes were generated. Because of increasing reliance on coal for producing electricity, by the year 2000 the amount of ash waste is expected to increase by about 75 percent to about 120 million tons annually; production of FGD wastes is expected to triple to about 50 million tons annually.[1] In addition to the high-volume ash and flue gas desulfurization wastes, coal-fired power plants also generate several lower-volume waste streams as a result of equipment maintenance and cleaning activities.

About one-fifth of all waste generated at coal-fired electric utility power plants is currently reused; the remaining four-fifths are typically disposed in surface impoundments or landfills. The recycled wastes, usually fly ash, bottom ash, or boiler slag, have been used primarily as cement additives, high-volume road construction material, and blasting grit. There is some potential for increased use of these wastes in such applications. However, barring the

[1] It is possible that advances in coal combustion technology will alter the amount and types of coal-combustion wastes produced in the future. An analysis of these technological advances is beyond the scope of this report.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 14 of 223

development of new utilization techniques, or major changes in combustion and environmental control technologies, the proportion of coal combustion wastes that are reused is unlikely to change significantly.

While utility waste management sites are currently exempt from RCRA hazardous waste requirements, they are subject to state and local level solid waste laws and regulations. There is substantial variation in the state-mandated disposal requirements.

Most utility waste management facilities were not designed to provide a high level of protection against leaching. Only about 25 percent of all facilities have liners to reduce off-site migration of leachate, although 40 percent of the generating units built since 1975 have liners. Additionally, only about 15 percent have leachate collection systems; about one-third of all facilities have ground-water monitoring systems to detect potential leachate problems. Both leachate collection and ground-water monitoring systems are more common at newer facilities.

The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause ground-water contamination. Although most of the materials found in these wastes do not cause much concern (for example, over 95 percent of ash is composed of oxides of silicon, aluminum, iron, and calcium), small quantities of other constituents that could potentially damage human health and the environment may also be present. These constituents include arsenic, barium, cadmium, chromium, lead, mercury, and selenium. At certain concentrations, these elements have toxic effects.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 15 of 223

To assess the potential threat to health and the environment posed by these wastes and to document any specific damage cases, EPA, other agencies, and various private organizations sponsored several studies. The main research efforts cited in this Report to Congress are a 1985 study by Arthur D. Little, Inc. for EPA, which characterized the environmental effects of waste disposal at several utility disposal sites, and a series of reports submitted to the Agency in 1982 by the Utility Solid Waste Activities Group, the Edison Electric Institute, and the National Rural Electric Cooperative Association.

The findings of these various research efforts indicate that most coal combustion wastes do not exhibit any of the four hazardous characteristics defined in RCRA Subpart C. The results of a substantial number of extraction procedure tests were examined; these tests indicated that metals do not generally leach out of coal combustion wastes at levels classified as hazardous under RCRA. The only metals which were found in any ash or sludge samples at "hazardous" levels were cadmium and arsenic. For boiler cleaning wastes, chromium and lead were sometimes found at levels classified as hazardous under RCRA. This waste stream was also found to be corrosive in a number of samples. Results of EP Tests performed on co-disposed high and low volume wastes indicate, however, that boiler cleaning wastes do not exhibit hazardous characteristics when co-disposed with ash.

While most of the laboratory results indicated that coal combustion wastes do not possess RCRA hazardous characteristics, in some instances, data on actual field observations indicate that migration of potentially hazardous constituents from utility waste disposal sites has occurred. For example, observed

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 16 of 223

concentrations of contaminants found in ground water downgradient from the sites exceed the Primary Drinking Water Standards about 5 percent of the time. Although the magnitude of the PDWS exceedances are typically not many times greater than the standard, a large number of disposal facilities report at least one PDWS exceedance at some time.

While a causal connection cannot always be made between the utility waste disposal site and the presence of contaminants at concentrations in excess of these standards, the available information indicates that some ground-water contamination from utility disposal sites is indeed occurring. The actual potential for exposure of human and ecological populations is likely to be limited, however, since ground water in the vicinity of utility waste disposal sites is not typically used for drinking water; the concentrations of contaminants in the ground water also tend to be diluted in nearby surface water bodies. These surface water bodies are typically used by electric utilities in the power plants for cooling and other purposes.

The electric utility industry currently spends about $800 million annually to dispose of its coal-fired combustion wastes. Under current practices, costs for waste management at most basic facilities range from as little as $2 per ton to as much as $31 per ton. Mitigative measures to control potential leaching include installation of liners, leachate collection systems, and ground-water monitoring systems and corrective action to clean up ground-water contamination. These mitigative measures, which are currently used at some utility waste disposal sites, may reduce the likelihood of ground-water contamination, but may also substantially increase disposal costs. For example,

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 17 of 223

the incremental cost of new waste disposal practices, excluding corrective action costs or higher recycling costs, could range up to $70 per ton, or $3.7 billion annually if all wastes were listed as hazardous. While substantial on a total cost basis, these increases would be unlikely to significantly affect the rate at which existing power plants consume coal. Due to the competitiveness of alternative fuels for electricity generation at future power plants, however, any increase in disposal costs could potentially slow the growth in electric utility coal consumption in future years. Moreover, if new disposal standards require corrective action measures as set forth in 40 CFR 264.100, the costs to utilities could be extremely high and could have a substantial effect on the utility industry.

Based on the findings from this Report to Congress, the Agency presents three preliminary recommendations for those wastes included in the scope of this study. The recommendations are subject to change based on continuing consultations with other government agencies and new information submitted through the public hearings and comments on this report. Pursuant to the process outlined in RCRA 3001(b)(3)(C), EPA will announce its regulatory determination within six months after submitting this report to Congress.

First, EPA has concluded that coal combustion waste streams generally do not exhibit hazardous characteristics under current RCRA regulations. EPA does not intend to regulate under Subtitle C fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes. EPA's tentative conclusion is that current waste management practices appear to be adequate for protecting human health and the environment. The Agency prefers that these wastes remain under Subtitle D

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 18 of 223

authority. EPA will use section 7003 of RCRA and sections 104 and 106 of CERCLA to seek relief in any cases where wastes from coal combustion waste disposal sites pose substantial threats or imminent hazards to human health and the environment. Coal combustion waste problems can also be addressed under RCRA Section 7002, which authorizes citizen lawsuits for violations of Subtitle D requirements in 40 CFR Part 257.

Second, EPA is concerned that several other wastes from coal-fired utilities may exhibit the hazardous characteristics of corrosivity or EP toxicity and merit regulation under Subtitle C. EPA intends to consider whether these waste streams should be regulated under Subtitle C of RCRA based on further study and information obtained during the public comment period. The waste streams of most concern appear to be those produced during equipment maintenance and water purification, such as metal and boiler cleaning wastes. The information available to the Agency at this time does not allow EPA to determine the exact quantity of coal combustion wastes that may exhibit RCRA Subtitle C characteristics. However, sufficient information does exist to indicate that some equipment maintenance and water purification wastes do occasionally exhibit RCRA hazardous characteristics, and therefore, may pose a danger to human health and the environment. These wastes are similar to wastes produced by other industries that are subject to Subtitle C regulation, and waste management practices for coal combustion wastes are often similar to waste management practices employed by other industries. EPA is considering removing the exemption for all coal-fired utility wastes other than those identified in the first recommendation. The effect would be to apply Subtitle C regulation to any of those wastes that are hazardous by the RCRA characteristic tests. EPA

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 19 of 223

believes there are various treatment options available for these wastes that would render them nonhazardous without major costs or disruptions to the utilities.

Third, EPA encourages the utilization of coal combustion wastes as one method for reducing the amount of these wastes that need to be disposed to the extent such utilization can be done in an environmentally safe manner. From the information available to the Agency at this time, current waste utilization practices appear to be done in an environmentally safe manner. The Agency supports voluntary efforts by industry to investigate additional possibilities for utilizing coal combustion wastes.

Through its own analysis, evaluation of public comments, and consultation with other agencies, the Agency will reach a regulatory determination within six months of submission of this Report to Congress. In so doing, it will consider and evaluate a broad range of management control options consistent with protecting human health and the environment. Moreover, if the Agency determines that Subtitle C regulation is warranted, in accordance with Section 3004(x) EPA will take into account the "special characteristics of such waste, the practical difficulties associated with implementation of such requirements, and site-specific characteristics . . .," and will comply with the requirements of Executive Orders 12291 and 12498 and the Regulatory Flexibility Act.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 20 of 223

CHAPTER ONE

INTRODUCTION

This is the Environmental Protection Agency's Report to Congress on wastes from fossil fuel combustion, as required by section 8002(n) of the Resource Conservation and Recovery Act. It describes sources and quantities of utility waste, current utilization and disposal practices and alternatives to these practices, potential dangers to human health and the environment, and the costs of current and alternative waste management practices. This report is based on numerous literature reviews and contractor studies; EPA's RCRA Docket contains copies of the source materials that the Agency used in preparing this report.

1.1 Legislative History

Because Congress has amended the Resource Conservation and Recovery Act several times and EPA's regulatory program continues to evolve in response to these Congressional mandates and other additional information, a brief legislative and regulatory history is provided below.

The Resource Conservation and Recovery Act (RCRA, or the Act) of 1976 (Public Law 94-580) substantially amended the Solid Waste Disposal Act of 1965 and authorized the U.S. Environmental Protection Agency (EPA) to establish and enforce regulations concerning the identification, generation, transportation, and management of hazardous waste. These regulations would accomplish the Act's objectives of "...promote[ing] the protection of health and the environment ... and conserve[ing] valuable material and energy resources...."[1] RCRA comprises several subtitles, including Subtitle C-- Hazardous Waste

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 21 of 223

Management, and Subtitle D-- State or Regional Solid Waste Plans. The intent of the regulations promulgated under Subtitle C of the Act is that wastes identified as hazardous be properly managed from "cradle to grave," that is, from the time they are generated, during transport, throughout their use in various applications, and during disposal. As provided under RCRA Subtitle D, other wastes not considered hazardous as defined under Subtitle C are subject to State regulations.

On December 18, 1978, EPA proposed the first regulations to implement Subtitle C. In the course of preparing these regulations, EPA recognized that certain very large-volume wastes (e.g., wastes generated by utility power plants) could require special treatment:

> ... The Agency has very little information on the composition, characteristics, and the degree of hazard posed by these wastes, nor does the Agency yet have data on the effectiveness of current or potential waste management technologies or the technical or economic practicability of imposing the Subpart D standards [current RCRA section 3004--Standards applicable to owners and operators of hazardous waste treatment, storage, and disposal facilities] on facilities managing such waste.
>
> The limited information the Agency does have indicates that such waste occurs in very large volumes, that the potential hazards posed by the waste are relatively low, and that the waste generally is not amenable to the control techniques developed in Subpart D.[2]

Thus, the Agency proposed a limited set of regulations for managing large-volume wastes, pending an additional rulemaking. Until that rulemaking was completed, EPA proposed exempting utility wastes from storage and disposal regulations.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 22 of 223

On May 19, 1980, EPA promulgated the first regulations implementing Subtitle C of RCRA. By then, Congress was debating RCRA reauthorization, and both Houses had passed bills restricting EPA's ability to regulate utility wastes. Anticipating the enactment of legislation amending RCRA Section 3001, EPA excluded utility wastes from the promulgated regulations, writing in the preamble:

> The United States Senate and House of Representatives have each recently passed a bill to reauthorize and amend RCRA (S.1156 and H.R.3994). Both bills contain amendments to Section 3001 which, if enacted, would repeal or temporarily suspend EPA's authority to regulate certain utility and energy development wastes as hazardous wastes under Subtitle C. These bills are now awaiting action by a conference committee. Because it appears likely that Congress will act before November 19, 1980 [the end of the six month comment period on the promulgated interim final regulations and the date on which they would take effect] to exempt these wastes, EPA has temporarily excluded them from this regulation (see section 261.4(b)). This exclusion will be revised, if necessary, to conform to the legislation which is ultimately enacted.[3]

In fact, Congress did act before November 19, 1980; the Solid Waste Disposal Act Amendments (Public Law 96-482) were passed in October 1980.

As anticipated, the amendments temporarily exempted from regulation fly ash waste, bottom ash waste, boiler slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels. In section 8002(n), Congress directed EPA to produce a report on the kinds of waste generated by the combustion of coal and other fossil fuels, which would include an analysis of eight topics:

1. the source and volumes of such material generated per year;

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 23 of 223

2. present disposal and utilization practices;

3. potential danger, if any, to human health and the environment from the disposal and reuse of such material;

4. documented cases in which danger to human health or the environment from surface runoff or leachate has been proved;

5. alternatives to current disposal methods;

6. the costs of such alternatives;

7. the impact of those alternatives on the use of coal and other natural resources; and

8. the current and potential utilization of such materials.[4]

Finally, in section 3001(b)(3)(C), Congress directed that within six months after submitting this report, EPA must conduct public hearings and decide whether regulating the management of coal combustion wastes under Subtitle C is warranted. Once the decision is made, the Administrator must publish the Agency's regulatory determination in the Federal Register.

In a January 1981 letter,[5] Gary Dietrich, then Associate Deputy Assistant Administrator for Solid Waste, provided an interpretation of RCRA regulations concerning the exemption from regulation of fossil fuel combustion waste.[6] (This letter, as well as a February 18, 1981 memorandum that enclosed it as part of a mailing to EPA Regional Directors, is included as Appendix A.) The letter noted that the beneficial use of hazardous waste as a fuel was not subject to regulation, though it might well be subject to regulation in the future. This meant that utilities could burn as fuel a combination of

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 24 of 223

hazardous waste and coal, as long as more than 50 percent of the mixture was comprised of coal. The letter also addressed disposal, noting that wastes produced in conjunction with the burning of fossil fuels (e.g., cleaning and other maintenance-related wastes) may be exempt from Subtitle C regulations provided they are mixed and co-disposed or co-treated with fossil fuel wastes and provided "there is no evidence of any substantial environmental danger from these mixtures."[7] The letter concluded:

> ...Pending the completion of [further study on the hazards posed by waste from coal-fired utility plants and the collection of relevant data from the utility industry], EPA will interpret 40 CFR 261.4(b)(4) to mean that the following solid wastes are not hazardous wastes:
>
> (a) Fly ash, bottom ash, boiler slag, and flue gas emission control wastes resulting from (1) the combustion solely of coal, oil, or natural gas, (2) the combustion of any mixture of these fossil fuels, or (3) the combustion of any mixture of coal and other fuels, where coal makes up more than 50 percent of the mixture.
>
> (b) Wastes produced in conjunction with the combustion of fossil fuels, which are necessarily associated with the production of energy, and which traditionally have been, and which actually are, mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag, or flue gas emission control wastes from coal combustion.

This provision includes, but is not limited to, boiler cleaning solutions, boiler blowdown, demineralizer reagent, pyrites, and cooling tower blowdown.

In November 1984, Congress reauthorized RCRA by passing the Hazardous and Solid Waste Amendments (HSWA). These amendments restricted the land disposal

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 25 of 223

of certain hazardous wastes without treatment, established minimum technology requirements for landfills and surface impoundments, issued corrective action requirements for continuing releases at permitted facilities, and established interim status requirements for surface impoundments. Under this new legislation, EPA was granted some flexibility to promulgate regulations that take into consideration the unique characteristics of several types of large-volume wastes, including wastes generated by utility power plants. Specifically, if EPA determined that some or all of the wastes from fossil fuel combustion were subject to regulation under Subtitle C, EPA was empowered to modify the standards imposed by HSWA "...to take into account the special characteristics of such wastes, the practical difficulties associated with implementation of such requirements, and site-specific characteristics ... so long as such modified requirements assure protection of human health and the environment."[8]

The HSWA Conference Report accompanying H.R. 2867 (which in its final amended form was passed by both Houses of Congress as Public Law 98-616) provides clarification:

> This Amendment recognizes that even if some of the special study wastes [which include utility wastes as specified in Section 8002(n)] are determined to be hazardous it may not be necessary or appropriate because of their special characteristics and other factors, to subject such waste to the same requirements that are applicable to other hazardous wastes, and that protection of human health and the environment does not necessarily imply the uniform application of requirements developed for disposal of other hazardous wastes. The authority delegated to the Administrator under this section is both waste-specific and requirement-specific. The Administrator could also exercise the authority to modify requirements for different classes of wastes. Should these wastes become subject to the requirements of Section 3005(j), relating to the retrofit of surface impoundments, the Administrator could

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 26 of 223

> modify such requirements so that they are not identical to the requirements that are applied to new surface impoundments containing such wastes. It is expected that before any of these wastes become subject to regulation under Subtitle C, the Administrator will determine whether the requirements of Section 3004(c), (d), (e), (f), (g), (o), and (u), and Section 3005(j) should be modified.[9]

1.2. Scope and Sources

This report addresses only the wastes generated by coal-fired electric utility power plants. Because this industry generates the vast majority of all fossil fuel combustion waste (nearly 90 percent),[10] EPA decided to focus its study in this area. This study does not address oil- and gas-fired electric utility power plants or coal, oil and gas-fired industrial boilers.

A number of research projects were undertaken to provide data for this report. EPA sponsored a major study of current coal ash and flue gas desulfurization waste management practices at coal-fired electric utility power plants.[11] In this study comprehensive environmental monitoring was conducted, which included characterizing the wastes, soils, ground water, and surface water at six disposal sites. The contractor (Arthur D. Little, Inc.) evaluated the environmental effects of the disposal practices used at these six sites and, by inference, what effects may be present at other utility waste disposal sites. They also performed extensive engineering and cost evaluations of disposal practices at the six sites.

EPA also sponsored a separate study effort to develop information on the incidences of ground water contamination resulting from utility waste management practices.[12] In this study, contamination was defined as the presence of hazardous constituents at levels above primary drinking water

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 27 of 223

standards. The main source of information for this phase of the research was a review of case files at the state offices having responsibility for such matters.

In addition, the Agency also reviewed reports submitted by the Utility Solid Waste Activities Group (USWAG), the Edison Electric Institute (EEI), and the National Rural Electric Cooperative Association (NRECA).[13] The reports present information on the sources, volumes, and physical and chemical characteristics of waste streams; ground-water monitoring results assembled from various utility plants; damage case information from various sources; costs of complying with hazardous waste regulations; and resource recovery opportunities using utility wastes.

EPA also has incorporated findings from several documents prepared by the Department of Energy (DOE) and the Electric Power Research Institute (EPRI).[14] These reports examined the chemical composition of utility wastes, technologies for disposal and the costs associated with disposal, as well as results of leaching tests performed on utility wastes.

Finally, EPA gathered information from the Utility Data Institute's Power Statistics Database.[15] This database contains information concerning the size of utility power plants, location of power plants, the types of disposal technologies employed by each power plant, and the amount of waste produced by site and by region. The information on location of power plants was combined with hydrogeologic, population, and ecological profiles of these locations to analyze the potential for exposure to coal combustion wastes.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 28 of 223

1.3 Organization

The following chapters of this report address the eight issues (enumerated earlier in this chapter) as required by Section 8002(n) as they apply to coal-fired combustion wastes generated by electric utilities. Chapter Two of this report provides an overview of the U.S. electric utility industry. Chapter Three examines the amount and types of wastes that are generated. Chapter Four discusses current waste management and disposal practices used by the electric utility industry, as well as alternatives to these practices; a review of applicable State regulations is included in this chapter. Chapter Five reviews the potential and documented impact of these wastes on human health and the environment, and Chapter Six evaluates costs associated with current waste disposal practices and additional costs that could be incurred under a variety of alternative waste management practices. Finally, Chapter Seven summarizes the conclusions contained in the previous chapters and presents recommendations.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 29 of 223

CHAPTER ONE

NOTES

[1] Resource Conservation and Recovery Act of 1976 (RCRA), Section 1003(a).

[2] Federal Register, Volume 43, No. 243, December 18, 1978, pp. 58991-58992.

[3] Federal Register, Volume 45, No. 98, May 19, 1980, p. 33089.

[4] RCRA, Section 8002(n).

[5] Letter of January 13, 1981, from Gary N. Dietrich, Associate Deputy Assistant Administrator for Solid Waste, to Paul Elmer, Jr., Chairman of the Utility Solid Waste Activities Group.

[6] See 40 CFR 261.4.

[7] Gary N. Dietrich, January 13, 1981, op. cit.; for further information, see Congressional Record, February 20, 1980, p. H 1102, remarks of Congressman Bevill; also see remarks of Congressional Record, February 20, 1980, p. H 1104, remarks of Congressman Rahall.

[8] RCRA, Section 3004(x)

[9] H.R. Report 98-1133, pp. 93-94, October 3, 1984.

[10] Most fossil fuel combustion wastes are generated from coal. For example, as indicated in Physical-Chemical Characteristics of Utility Solid Wastes (by Tetratech, Inc. for EPRI, September 1983), only about one percent of utility wastes are generated from oil; the remaining 99 percent is largely attributable to coal-fired electricity production. Of the coal consumed in the U.S., electric utilities burn nearly 90 percent (excluding metallurgical coal, which is not burned but is instead converted into coke primarily for making steel).

[11] Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants. Prepared for EPA's Office of Research and Development, EPA Contract #68-02-3167; June 1985.

[12] Franklin Associates, Ltd., Survey of Groundwater Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for U.S. Environmental Protection Agency, March 1984.

[13] USWAG is an informal consortium of approximately 65 electric utility operating companies, EEI, and NRECA. The primary source used in the preparation of this report was Report and Technical Studies On The Disposal and Utilization of Fossil-Fuel Combustion By-Products, USWAG, EEI, and NRECA, October 26, 1982.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 30 of 223

[14] For example, see Impacts of Proposed RCRA Regulations and Other Related Federal Environmental Regulations on Utility Fossil Fuel-Fired Facilities; Prepared by Engineering-Science for DOE, DOE Contract Number DE-AC-01-79ET-13543, May 1983; Physical-Chemical Characteristics of Utility Solid Wastes, EPRI, September 1983; Analytical Aspects of the Fossil Energy Waste Sampling and Characterization Project, Prepared by Western Research Institute, DOE Order Number DE-AP20-84LC00022, March 1984; and Environmental Settings and Solid Residues Disposal in the Electric Utility Industry, EPRI, July 1984. More sources are included in the Bibliography.

[15] Utility Data Institute's Power Statistics Database was developed under the auspices of the Edison Electric Institute to assist in their analysis of issues affecting the electric utility industry.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 31 of 223

CHAPTER TWO

OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY

This chapter provides a general overview of the U.S. electric utility industry. Section 2.1 summarizes electricity demand and discusses the overall structure of the electric utility industry. Section 2.2 focuses the discussion on the role that coal plays in generating electricity. Section 2.3 provides details of coal-fired electric generating technologies and the regional characteristics of coal-fired plants. The chapter concludes with a discussion in Section 2.4 of the waste streams that are produced during coal combustion.

2.1 THE DEMAND FOR ELECTRICITY

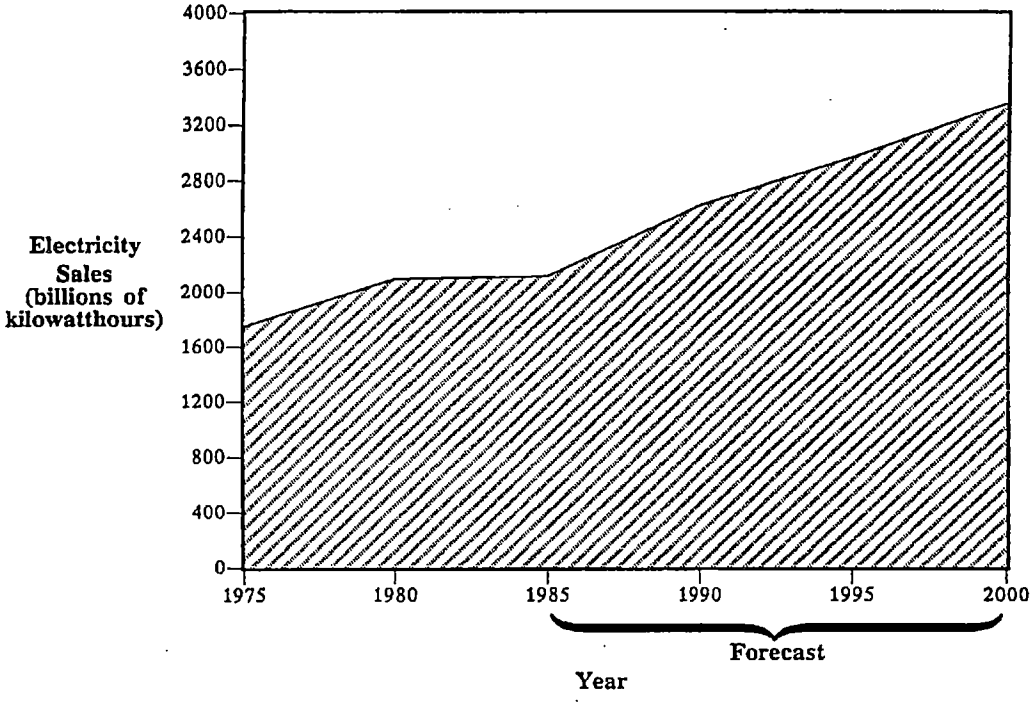
The generation, transmission, and distribution of electricity is one of our nation's largest industries. With annual revenues in excess of $140 billion and assets of about $500 billion, the electric utility industry provides vital services to nearly every person in the U.S.[1]

Total demand for electricity in the U.S. has increased substantially in recent decades and will likely continue to grow in coming years (see Exhibit 2-1). From the 1940's through the early 1970's, electricity demand grew at about 7 percent per year, doubling approximately every ten years. This growth slowed beginning with the 1973 OPEC oil embargo and subsequent changes in the energy markets such as fuel price increases, shifts in the economy to markets that require less electricity to meet their power needs, and energy conservation measures. Since 1973, growth in electricity demand has averaged

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 32 of 223

EXHIBIT 2-1

GROWTH IN ELECTRICITY DEMAND - 1975-2000



Sources: 1975-1985: Energy Information Administration, Electric Power Monthly, DOE/EIA-0226 (85/12), December 1985, p. 39.

1985-2000: ICF Incorporated, Analysis of 6 and 8 Million ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 33 of 223

about three percent per year. Expectations are that electricity demand will continue to grow at an average rate of about 2 to 3 percent per year over the next several years.[2]

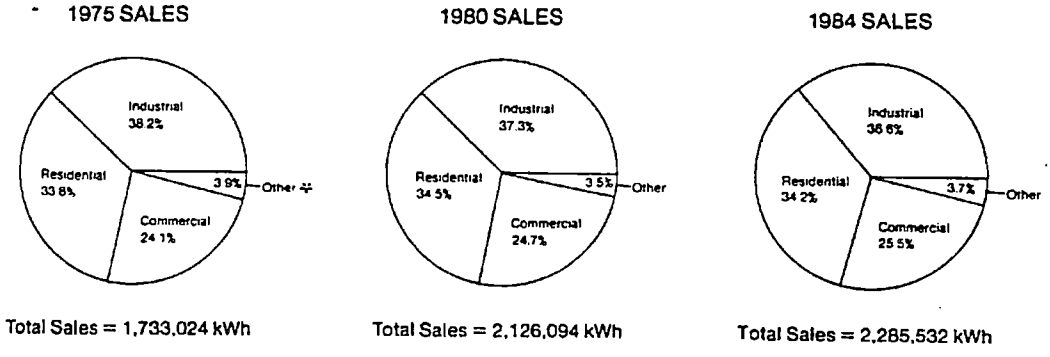
Every major segment of the U.S. economy relies on electricity to meet a portion of its energy needs. As shown in Exhibit 2-2, the demand for electricity is divided almost evenly between the industrial, commercial, and residential sectors. This demand for electricity has continued to increase over the last decade with total sales increasing from 1.7 million gigawatt-hours (Gwh) in 1975 to 2.3 million Gwh in 1985.[3] As demand has increased, electricity sales patterns have remained relatively consistent. Industry continues to be the largest consuming sector, although industry's fraction of total sales has decreased by about 2.7 percent from 1975 to 1985, primarily due to an increased market share for the commercial sector (i.e., stores, office buildings, restaurants, etc.). Residential customers consume about one-third of all electricity for basic necessities such as lighting, heating, and electrical appliances.

Virtually every geographic area in the U.S. relies on electricity supplied by the electric utility industry. As shown in Exhibit 2-3, electricity demand is highest in the eastern half of the U.S., particularly in EPA Regions 3-6 (see Exhibit 2-4 for a map of these EPA Regions). This level of demand is not surprising considering that these areas are the most heavily industrialized and densely populated areas of the country.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 34 of 223

EXHIBIT 2-2

ELECTRICITY SALES BY YEAR AND CLASS OF SERVICE
(gigawatt-hours)



Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry/1985, December 1986.

*Includes street lighting, other public authorities, railroads and interdepartmental transfers within utilities (i.e., use of electricity by the utility itself).

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 35 of 223

EXHIBIT 2-3

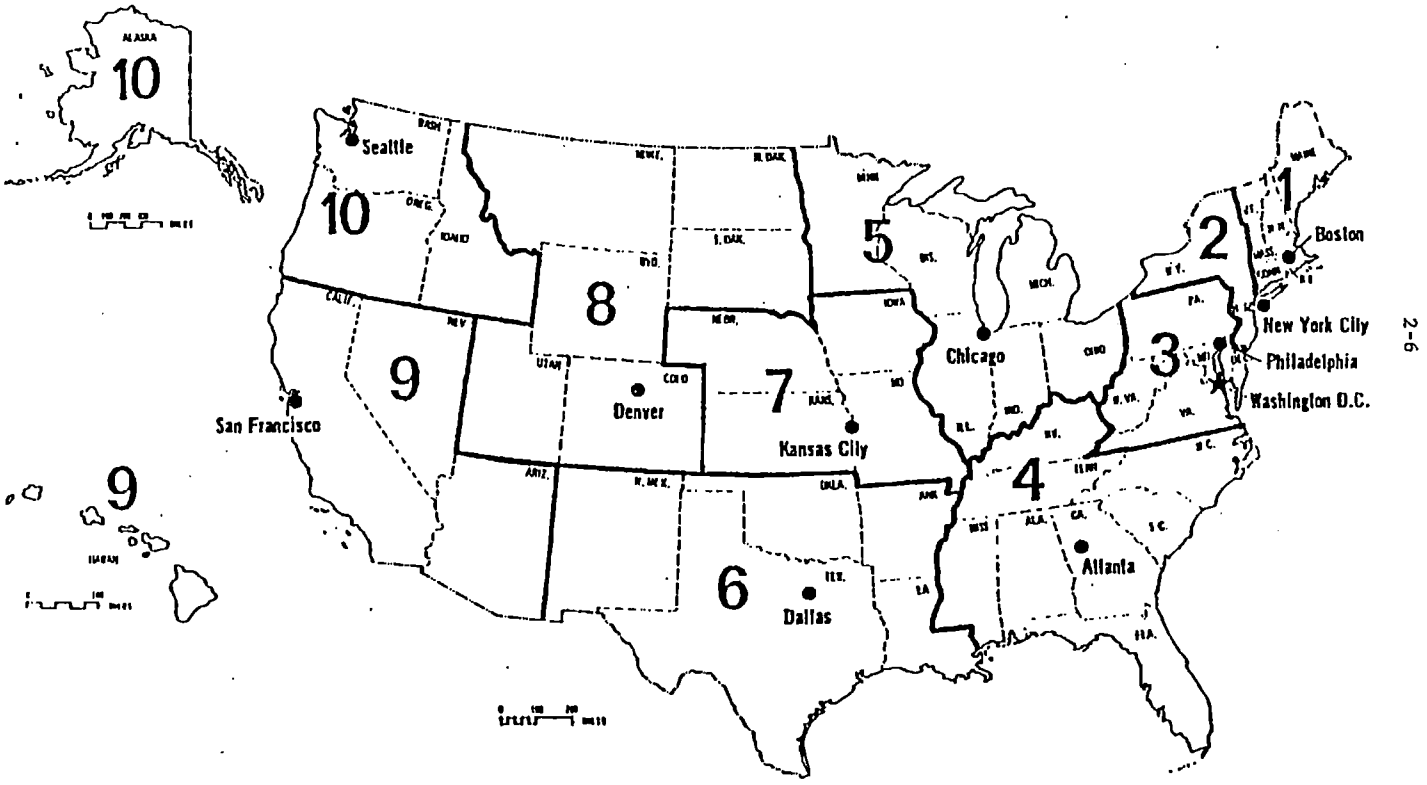
ELECTRICITY DEMAND by EPA REGION
1985

EPA Region	Millions of Kilowatt Hours	Percent of Total
1	86,397	3.8
2	164,780	7.2
3	230,055	10.1
4	483,248	21.2
5	428,873	18.8
6	340,198	14.8
7	112,076	4.9
8	72,458	3.2
9	227,006	10.0
10	135,716	6.0
Total U.S.	2,280,585	100.0

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry/1985, December 1986.

EXHIBIT 2-4

EPA FEDERAL REGIONS



ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 36 of 223

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 37 of 223

2.1.1 Structure of the U.S. Electric Utility Industry

The U.S. electric power industry is a combination of private, Federal, and public nonprofit organizations. The distribution of capacity, generation, revenue, and sales differs widely among these ownership groups since each group has different objectives, organizational characteristics, and financing methods. Private investor-owned utilities dominate the U.S. electric utility industry as shown in Exhibit 2-5. Investor-owned utilities have historically served large consolidated markets to take advantage of economies of scale. Federal, municipal, cooperative, and other publicly-owned utilities have generally served smaller markets where local governments or nonprofit organizations have had access to limited supplies of less expensive Federal power or to government-supplied capital for power plant construction. These circumstances have allowed municipal, cooperative, or other publicly-owned utilities to predominate in areas not traditionally served by investor-owned utilities.[4] A brief discussion of each type of organization is provided below.

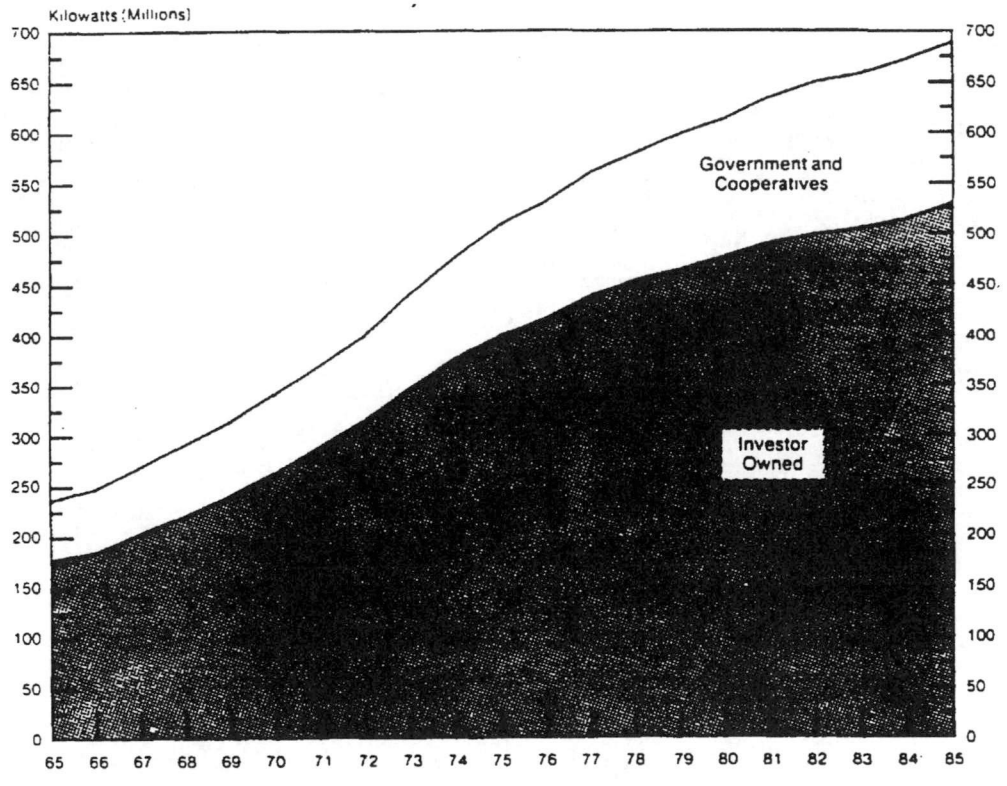
2.1.1.1 Investor-Owned Utilities

Investor-owned utilities account for about three-quarters of all U.S. electric utility generating capacity, generation, sales, and revenue. Investor-owned utilities are privately owned, profit-oriented businesses granted service monopolies in certain geographic areas. As franchised monopolies, they are obligated to provide service to all customers within their geographic area. In providing this service, investor-owned utilities are required to charge reasonable prices, to charge similar prices to similar

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 38 of 223

EXHIBIT 2-5

GENERATING CAPACITY IN THE UNITED STATES



Source: Edison Electric Institute, Statistical Yearbook for the Electric Utility Industry/1985, December 1986.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 39 of 223

customers, and to give customers access to services under similar conditions.[5] Investor-owned utilities operate in all states except Nebraska (which depends primarily on public power districts and rural electric cooperatives for electricity). In 1984, consumers paid an average of 6.5 cents per kilowatt-hour (kwh) for privately-produced power compared to the industry average from all ownership groups of 6.3 cents per kilowatt-hour (an average customer consumed 23,150 kwh in 1984).[6]

2.1.1.2 Federal Power

The U.S. Government is the second largest producer of electricity in the United States with roughly 10 percent of total U.S. generation and generating capacity. Consumers of Federal power paid the lowest rate among the different ownership groups -- only 3.5 cents per kwh on average in 1984, (compared to an industry average of 6.3 cents per kwh).[7] Federal power production is designed to provide power at the lowest possible rate, with preference in the sale of electricity given to public entities and cooperatives.[8] In this role the Federal Government is primarily a generator and wholesaler of electricity to other organizations, rather than a direct distributor to electricity consumers.[9]

2.1.1.3 Municipal Utilities

Municipal utilities are nonprofit local government agencies designed to serve their customers at the lowest possible cost. Most municipal utilities simply distribute power obtained from one of the other ownership groups (e.g., Federal facilities), although some larger ones also generate and transmit

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 40 of 223

power. Municipally-owned electric utilities rank third in the amount of installed capacity (5.5 percent of total generating capacity), but comprise the single most numerous ownership group (1,811 utilities in 1984).[10] Average revenue per kwh sold in 1984 was 5.69 cents compared to an industry average of 6.3 cents per kwh. Municipal utilities are exempt from local, state, and Federal taxes and have access to less expensive capital via public financing and less expensive Federal power. As a result, municipal utilities can generally afford to charge less than investor-owned utilities for the power they produce.[11]

2.1.1.4 Cooperatives

Rural electric cooperatives are owned by and provide electricity to their members and currently operate in 46 states. They have the lowest amount of installed capacity among all ownership categories (24.7 gigawatts in 1984 or less than 4 percent of all capacity).[12]

In 1984, average revenue for cooperatives from sales to consumers was 6.7 cents per kwh, the highest of all ownership types (the industry average was 6.3 cents per kwh). Large construction programs in the 1970's usually account for the high rates.[13]

2.1.1.5 Other Public Entities

There are a variety of other public organizations that provide electric power, including public power districts, state authorities, irrigation districts, and various other State organizations. These other public entities

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 41 of 223

operated a combined total of 32.8 gigawatts in 1984, or about 5 percent of all generating capacity in the U.S.[14] The public power districts are concentrated in five states -- Nebraska, Washington, Oregon, Arizona, and California. The average price paid for electricity from all of these entities was 4.37 cents per kwh in 1984, compared to an industry average of 6.3 cents per kwh.[15]

2.1.2 Economic and Environmental Regulation of the Electric Utility Industry[16]

The electric utility industry is regulated by several different regulatory bodies at both the Federal and State levels. According to the U.S. Department of Energy: "The basic purpose of public utility regulation is to assure adequate service to all public utility patrons, without discrimination and at the lowest reasonable rates consistent with the interests both of the public and the electric utilities."[17] This regulation involves both economic and environmental objectives. As natural monopolies, electric utilities are regulated to ensure that adequate, reliable supplies of electric power are available to the public at a reasonable cost. Additionally, since the operations of electric utilities can affect environmental quality, they are regulated to ensure the protection of the nation's air and water resources. This section briefly reviews the main regulatory bodies that affect the electric utility industry.

2.1.2.1 Federal Regulation

There are five major organizations at the Federal level that regulate some aspect of the electric utility industry -- the Federal Energy Regulatory Commission (FERC), the Economic Regulatory Administration (ERA), the

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 42 of 223

Securities and Exchange Commission (SEC), the Nuclear Regulatory Commission (NRC), and the Environmental Protection Agency (EPA).

- The Federal Energy Regulatory Commission (FERC) oversees various aspects of the electric utility, natural gas, hydroelectric, and oil pipeline industries. FERC approves the rates and standards for wholesale interstate electricity sales between investor-owned utilities and other investor-owned utilities, municipals, or cooperatives (these sales are about 15 percent of total U.S. electricity sales).[18] It determines whether these rates are reasonable and non-discriminatory. FERC also oversees utility mergers and the issuance of certain stock and debt securities, approves the rates of Federal Power Marketing Administrations, and administers agreements between utilities concerning electricity transmission.

- The Economic Regulatory Administration (ERA) has several responsibilities, including administering a program to ensure that all future power plants have the potential to burn coal, regulating international electricity transmission connections, and licensing exports of power.

- The Securities and Exchange Commission (SEC) is an independent regulatory agency established to regulate interstate transactions in corporate securities and stock exchanges. With respect to the electric utility industry, the SEC regulates the purchase and sale of securities, utility properties, and other assets.

- The Nuclear Regulatory Commission (NRC) is involved only in the regulation of nuclear facilities owned and operated by the utility industry. Its main responsibilities include licensing the construction and operation of nuclear facilities, licensing the possession, use, transportation, handling, and disposal of nuclear materials, licensing the export of nuclear reactors and the import and export of uranium and plutonium, and regulating activities affecting the protection of nuclear facilities and materials.

In addition to these regulatory bodies, the Environmental Protection Agency (EPA) is the main Federal regulatory authority for protecting the nation's air and water quality. As part of its overall authority, EPA sets limits on the level of air pollutants emitted from electric power plants and develops regulations to control discharges of specific water pollutants.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 43 of 223

Throughout this Report to Congress key regulations that affect the electric utility industry are discussed. While EPA often takes the Federal lead when these regulations are developed, the Agency also works closely with the States since they often retain primary authority for implementing and enforcing standards (for example, see Section 4.1 on state regulation of coal combustion wastes).

2.1.2.2 State Regulation

States are also involved in the environmental and economic regulation of the electric utility industry. As mentioned above, the States often share regulatory authority with the various Federal organizations. For environmental regulation the States often have their own environmental protection agencies to implement and enforce State and Federal environmental regulations. For example, they are responsible for drafting State Implementation Plans (SIP) that must be approved by the U.S. EPA to attain National Ambient Air Quality Standards (NAAQS). Similarly, as will be discussed in greater detail in Chapter Four, the States have authority for implementing and enforcing regulations concerning the disposal of solid wastes under Subtitle D of RCRA. Environmental regulations for which the States exercise regulatory authority are discussed throughout this Report to Congress.

States are also very involved in the economic regulation of the electric utility industry. The primary goals of state economic regulation is usually to provide adequate nondiscriminatory service to electricity consumers at reasonable prices.[19] This is usually accomplished by state regulatory

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 44 of 223

agencies such as public utility commissions. The amount of authority these state regulatory agencies have can differ widely from state to state. However, these agencies usually have the authority to approve electricity price levels and the rates of return allowed for utility stockholders. State regulators also approve the franchise under which the utility operates. Licensing for construction and operation and approval of the sites at which power plants will be built are also important functions of some state regulatory commissions. Other areas into which some commissions have entered to ensure that utility activities protect the public interest include setting rules about when competitive bids are required, promulgating company performance standards, deriving methods for allocating power during shortages, establishing billing and safety rules, and promoting conservation.[20]

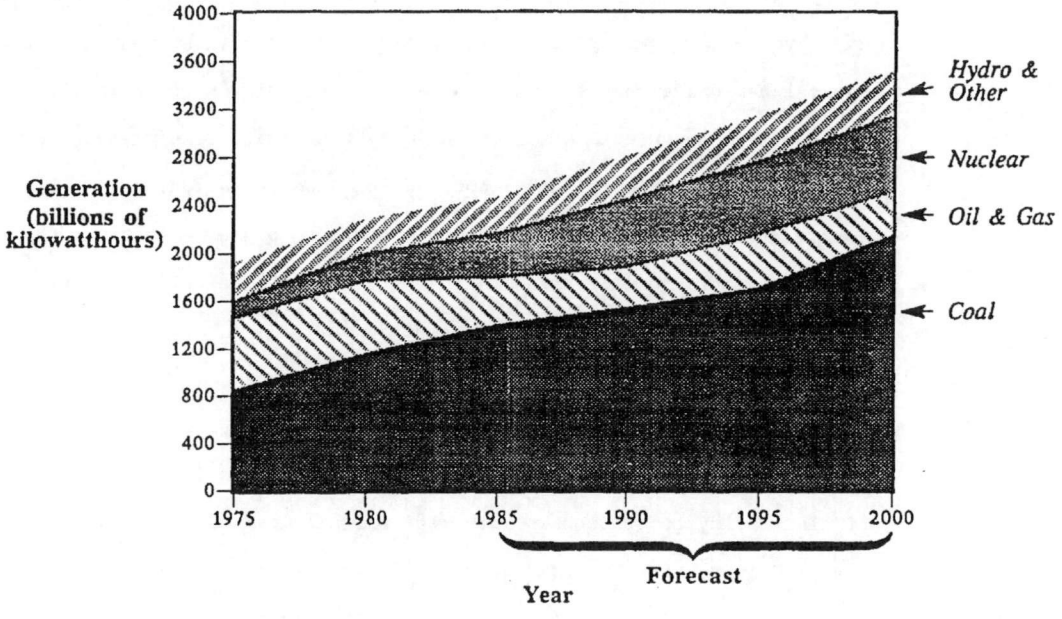
2.2 IMPORTANCE OF COAL TO ELECTRIC UTILITIES

Electric utilities use many different technologies and energy sources to generate electricity. At present, as shown in Exhibit 2-6, over 70 percent of electricity in the U.S. is generated by the combustion of fossil fuels (coal, oil and natural gas); most of the remaining 30 percent is generated by hydroelectric plants and nuclear power plants. A small portion of electricity demand is satisfied by alternative sources such as geothermal energy, renewable resource technologies (e.g., wood, solar energy, wind), purchased power from industrial and commercial cogeneration (cogeneration is the simultaneous production of electricity and process steam; the electricity is typically used by the cogenerator or sold to another industry while the steam is used for various production processes), and power imports (primarily from Canada).

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 45 of 223

EXHIBIT 2-6

**ELECTRICITY GENERATION BY PRIMARY ENERGY SOURCE
1975-2000**



Source: 1975-1985: Energy Information Administration, Electric Power Monthly DOE/EIA-0226 (85/12), December 1985, p. 10.

1985-2000: ICF Incorporated, Analysis of 6 and 8 million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 46 of 223

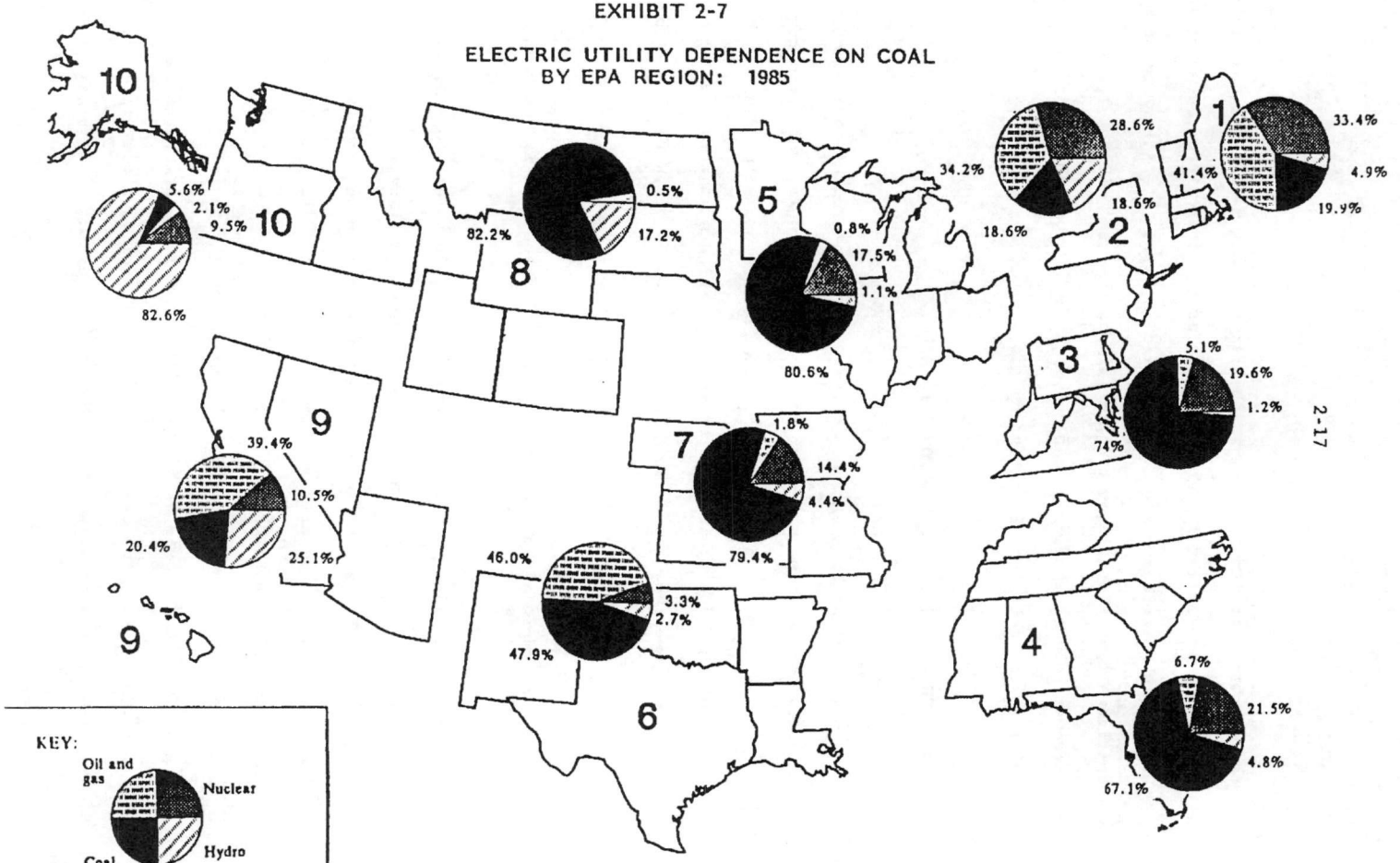
In 1984, coal accounted for more than half of all the electricity generated in the U.S.[21] The portion of electricity generated from coal is expected to remain at about this level throughout the rest of the century since coal-fired generation is expected to remain economically attractive. The relative contribution to total generation made by other fossil fuels and by hydroelectric power will likely continue to decline, while the contribution made by nuclear power plants will likely increase for the next few years as several new units come on-line. However, the addition of nuclear plants beyond those now under construction will be minimal, leading to an eventual decline in nuclear's relative contribution. Cogeneration, power imports, and emerging technologies are expected to continue to grow, but their share of total generation will remain small. As a result, coal will continue to be the major fuel source for electricity generation.

The extent of the electric utility industry's dependence on coal varies geographically. Exhibit 2-7 shows that coal accounts for over three-quarters of electricity generation in some regions, but less than half in others. For example, in the far West and southern Plains states, the local availability of oil, gas, and hydroelectric power has limited regional dependence on coal. In many of the eastern regions, where coal is relatively more accessible and less costly than oil or gas, coal is significantly more dominant. Despite these regional variations, however, coal-fired electricity generation is an important source of electricity in most regions of the United States.

The use of coal by electric utilities has also made the coal and electric utility industries highly interdependent; not only does coal-fired electricity generation account for over half of the electricity produced in the U.S., but

EXHIBIT 2-7

ELECTRIC UTILITY DEPENDENCE ON COAL
BY EPA REGION: 1985



Source: Energy Information Administration, Electric Power Annual 1985, DOE/EIA-0348(85), pp.17-30.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 47 of 223

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 48 of 223

the electric utility industry is the largest customer of the coal industry, purchasing approximately three-quarters of all coal mined, as shown in Exhibit 2-8. This interdependence has increased as electric utility coal consumption has grown from 406 million tons in 1975 to over 600 million tons in 1985.[22] Moreover, electric utility coal consumption is expected to continue to increase to about 1 billion tons by the year 2000.

2.3 OVERVIEW OF COAL-FIRED POWER PLANTS

Coal-fired power plants can vary greatly in terms of their generating capacity and the type of boiler technology they employ which, in turn, can affect the amount and type of combustion wastes produced. This section discusses the geographic differences in the size of plants and generating units and describes the three main boiler types along with the regional importance of each.

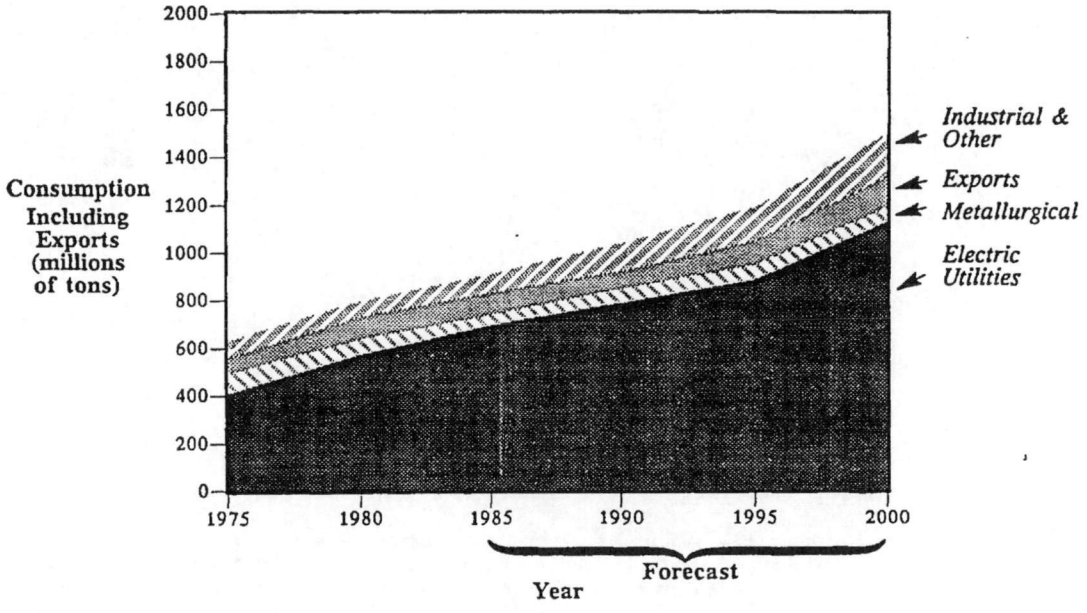
2.3.1 Regional Characteristics of Coal-Fired Electric Generating Plants

Coal-fired power plants can range in size from less than 50 MW to larger than 3000 MW. In many cases, particularly at the larger power plants, one power plant site may be the location for more than one generating unit (a generating unit is usually one combination of a boiler, turbine, and generator for producing electricity). Exhibit 2-9 shows the number of coal-fired power plants and number of units in each EPA region and their average size in megawatts. On average, each power plant site is comprised of about three generating units. The average generating capacity of coal-fired power plants in the U.S. is approximately 584 MW, with an average unit size of 257 MW.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 49 of 223

EXHIBIT 2-8

U.S COAL CONSUMPTION BY SECTOR
1975-2000



Sources: 1975-1985: Energy Information Administration, Annual Energy Review 1985, DOE/EIA-0384 (85), April 1985, pp. 167, 169.

1985-2000: ICF Incorporated, Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 50 of 223

EXHIBIT 2-9

TOTAL NUMBER AND AVERAGE SIZE OF COAL-FIRED PLANTS AND UNITS

EPA Region	Number of Plants	Average Size (MW)	Number of Units a/	Average Size a/ (MW)
1	6	374	18	158
2	17	297	39	138
3	57	753	144	308
4	93	799	295	301
5	171	492	492	185
6	39	852	87	580
7	66	400	149	186
8	48	454	109	250
9	13	603	34	383
10	4	479	11	382
U.S. Total	514	584	1378	257

Source: Utility Data Institute Power Statistics Database.

a/ The total amount of generating capacity indicated by multiplying the number of units by their average size (e.g., 1378 units X 257 Mw = 354,146 Mw) is greater than the amount indicated by multiplying the number of power plants by their average (e.g., 514 plants X 584 Mw = 300,176 Mw) because the information in the UDI Power Statistics Database by generating units includes units planned, currently under construction, etc. while the information by power plants refers only to power plants currently operating.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 51 of 223

Regional averages for power plant size range from 297 MW in Region 2 to 852 MW in Region 6. Unit sizes range from an average of 138 Mw in Region 2 to 580 Mw in Region 6. Individual power plants and units can be larger or smaller than these averages indicate.

The majority of coal-fired plants (60%) are smaller than 500 MW, while only about 4 percent of U.S. coal-fired power plants have a generating capacity exceeding 2000 MW. Exhibit 2-10 shows the distribution of coal-fired plant sizes across EPA regions.

2.3.2 Electricity Generating Technologies

The basic process by which electricity is produced with coal is shown in Exhibit 2-11. When coal is burned to produce electricity, there are three key components that are critical to the operation of the power plant: the boiler, turbine, and generator. As coal is fed into the boiler, it is burned in the boiler's furnace. In the boiler there are a series of water-filled pipes. As heat is released during combustion, the water is converted to steam until it reaches temperatures that can exceed 1000°F and pressures that approach 4000 pounds per square inch. This high pressure, high temperature steam is then injected into a turbine, causing the turbine blades to rotate. The turbine, in turn, is connected to a generator, so the mechanical energy available from the rotating turbine blades is transformed into electrical energy. The electricity produced by this process is distributed via transmission lines to residential, commercial, and industrial end-users who rely on the power to meet their electrical requirements. Although each step of this process is critical to the production of electricity, this study focuses on boilers only

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 52 of 223

EXHIBIT 2-10

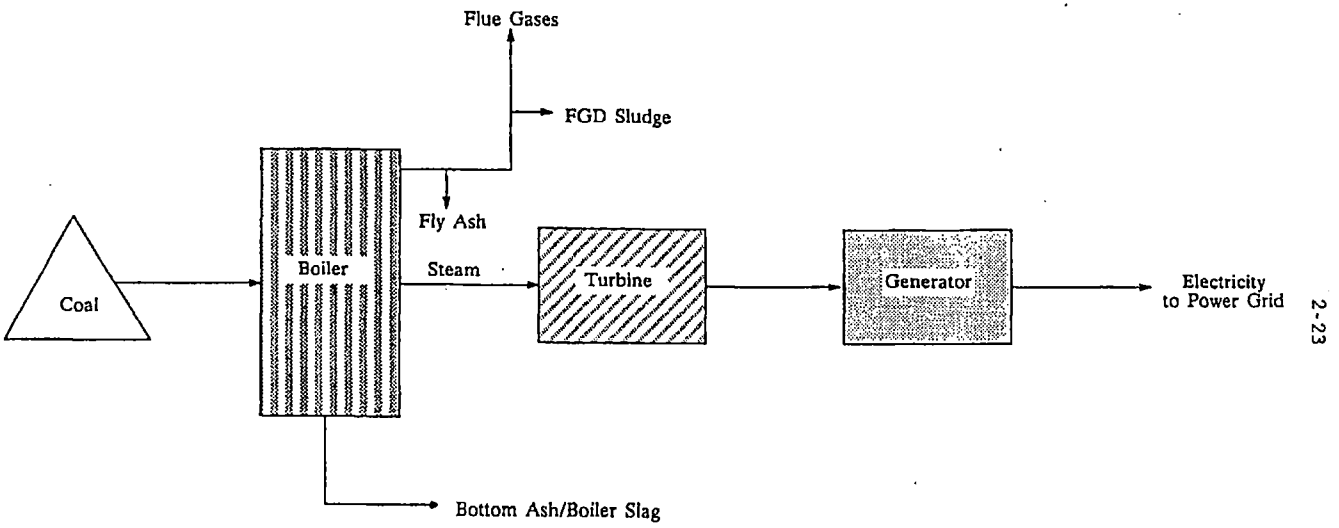
RANGE OF COAL-FIRED POWER PLANT SIZES
(number of plants)

	Power Plant Size					
EPA Region	<100 MW	101-500 MW	501-1000 MW	1001-2000 MW	≥2000 MW	Total
1	1	4	0	1	0	6
2	6	6	5	0	0	17
3	6	23	11	14	3	57
4	15	31	17	23	7	93
5	63	51	23	29	5	171
6	10	4	10	12	3	39
7	25	24	8	7	2	66
8	18	14	10	4	2	48
9	5	2	4	1	1	13
10	2	0	1	1	0	4
U.S. Total	151	159	89	92	23	514

Source: Utility Data Institute Power Statistics Database.

EXHIBIT 2-11

PROCESS FOR GENERATING ELECTRICITY
AT COAL-FIRED POWER PLANTS



Source: ICF Incorporated

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 53 of 223

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 54 of 223

since it is in the boiler where the combustion wastes are produced as the coal is burned.

There are three main types of boilers: (1) pulverizers, (2) cyclones, and (3) stokers. As discussed below in greater detail, the key differences between these boiler types are operating size and the procedures used for handling and burning the coal. Pulverized coal boilers are so-named because the coal is finely pulverized prior to combustion; most utility boilers are this type. Cyclones have been used in past utility applications, but have not been built recently. They are called cyclones because of the cyclone-like vortex created by the coal particles in the furnace during combustion. Stoker boilers are usually used when smaller capacities are required (e.g., 20-30 MW) and burn coal in a variety of sizes.

A brief description of each of these coal combustion technologies follows.[23]

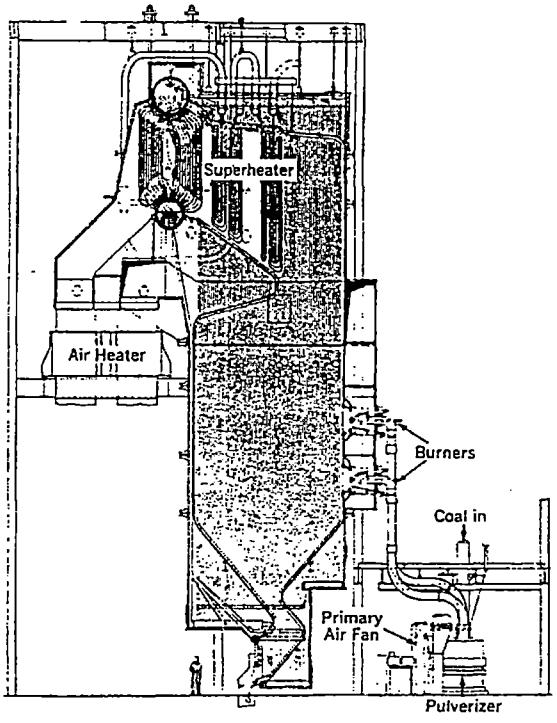
2.3.2.1 Pulverized-Coal Boiler

Exhibit 2-12 shows a typical pulverized-coal boiler setup. In a pulverized coal boiler, coal is ground to a fine size (about 200 mesh, which is powder-like) in a pulverizer or mill. The pulverized fuel is then carried to the burners by forced air injection and blown into the furnace, where it is burned in suspension. Much of the ash remaining after combustion remains airborne and is carried from the furnace by the flue gas stream (i.e., it becomes fly ash; see Chapter Three for a more detailed discussion of types of waste and how they are produced). Some ash is deposited on the furnace walls,

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 55 of 223

EXHIBIT 2-12

DIAGRAM OF A PULVERIZED COAL BOILER



Two-drum boiler direct-fired with pulverized coal.

Source: Babcock and Wilcox Co., Steam: Its Generation and Use, New York, NY 1978.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 56 of 223

where it agglomerates and may sinter or fuse. Ash that falls to the bottom of the furnace is removed via an ash hopper. Ash deposits and slagging are more of a problem in pulverized coal boilers than in stoker boilers.

Most modern pulverized-coal boilers have dry-bottom furnaces; that is, the ash is intended to be removed as a dry solid before complete melting occurs. As a result, for dry-bottom boilers, the ash-fusion temperature (the melting point) of the coal must be high enough to prevent the ash from becoming a running slag (i.e., a liquid form). Wet-bottom, or slag-tap, pulverized-coal boilers are designed to remove the ash as a flowing slag. These boilers depend on lower ash-fusion temperature coals so that the ash will melt to form slag for easier removal.

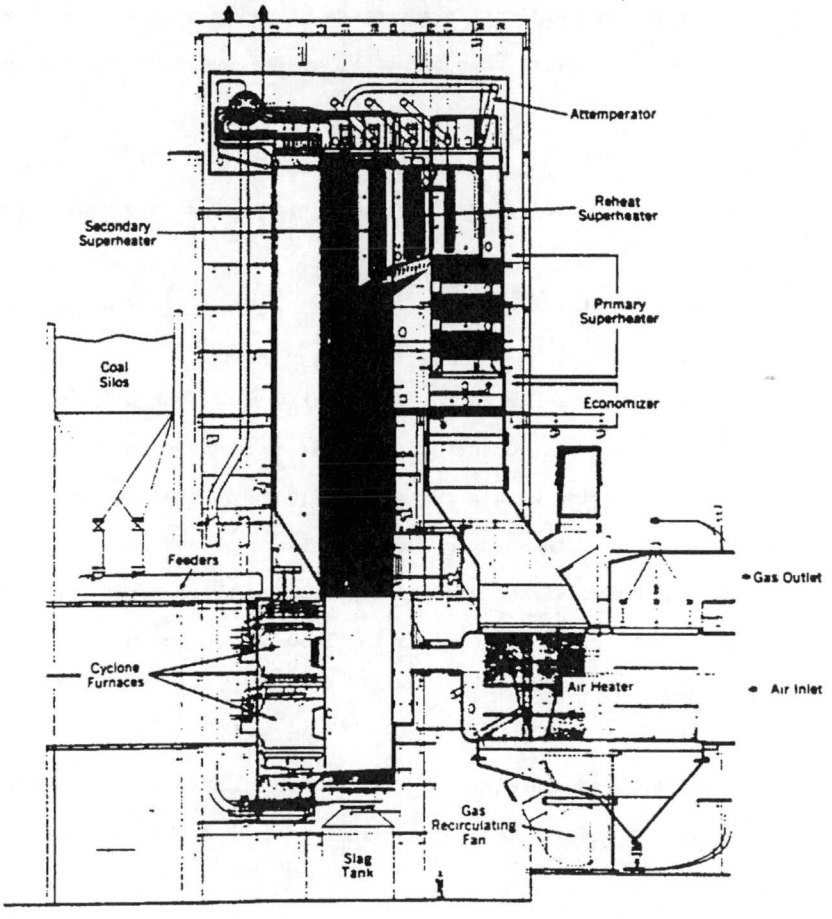
2.3.2.2 Cyclones

The cyclone furnace consists of a water-cooled horizontal furnace in which crushed coal is fired and heat is released at high rates, as shown in Exhibit 2-13. The temperature inside the furnace may reach 3000°F, which is sufficient to melt the ash into a liquid slag that forms on the walls of the furnace. Air circulation within the furnace typically creates a cyclone-like vortex that not only helps the coal to burn in suspension but also causes many coal particles to impinge upon the slag-covered walls of the furnace. This tendency for coal particles to adhere to the walls of the cyclone boiler aids the combustion process because the coal particles will burn more thoroughly before reaching the bottom of the boiler. Most of the ash is retained in the slag layer, thus minimizing the amount of fly ash that is carried out of the boiler. The slag,

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 57 of 223

EXHIBIT 2-13

DIAGRAM OF A CYCLONE BOILER



Source: Babcock and Wilcox Co., Steam: Its Generation and Use, New York, NY, 1978.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 58 of 223

or melted ash particles, is typically removed at the bottom of the furnace.

The cyclone offers the advantage of being able to burn low ash-fusion coals that create problems when burned in most conventional pulverized-coal burners. The cyclone design also helps to minimize erosion and fouling problems in the boiler. The smaller amounts of fly ash created compared to other boiler types reduces the costs associated with particulate collection.

2.3.2.3 Stokers

Stokers are designed to mechanically feed coal uniformly onto a grate within a furnace. Because most of the combustion takes place in the fuel bed, not in suspension within the furnace, the heat release rate of this type of boiler is lower than it is for pulverizers or cyclones. As a result, stokers are generally designed for smaller-sized applications. In fact, this boiler type is used by many manufacturing industries, but has seen only limited use by electric utilities.

Stokers are classified by the method of feeding fuel to the furnace and by the type of grate. The three most important stoker types include:

1) the spreader stoker, the most popular type of overfeed stoker,

2) other overfeed stokers, such as the chain-grate, travelling-grate stoker, or the vibrating-grate stoker, and

3) the underfeed stoker.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 59 of 223

The major features of each are summarized in Exhibit 2-14. An illustration of a spreader stoker is provided in Exhibit 2-15.

Use of the different boiler types varies by geographic region. As shown in Exhibit 2-16, about three-fourths of all boiler capacity in the U.S. uses pulverizers, with most of these dry-bottom pulverizers. Cyclones are the next most prevalent boiler type, representing only about 8 percent of all boilers. Stokers represent less than one-half of one percent of the total; due to their size limitations stokers are used primarily in other industrial applications for the production of steam.

Exhibit 2-17 shows the distribution of average capacity for each boiler type by EPA region. The range in average sizes is most pronounced in dry bottom boilers (127.8-610.0 MW), which reflects their substantial flexibility in terms of size and dominance in electric utility applications. Stokers tend to have the smallest capacities (an average of 14 MW nationwide), limiting their usefulness in utility applications compared to all of the other boiler types.

2.4 COAL CONSTITUENTS AND BY-PRODUCTS

Despite its attractiveness as a power plant fuel, coal has its drawbacks. As a solid fuel, coal is often more difficult and more costly to transport, store, and burn than oil or gas. Also, coal's many impurities require environmental control at various stages of the fuel cycle.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 60 of 223

EXHIBIT 2-14

CHARACTERISTICS OF VARIOUS TYPES OF STOKERS

Stoker Type & Subclass	Typical Maximum Capacity Range (pph steam) a/	Burning Rate (Btu/hr/ft^2) b/	Characteristics
1. Spreader			Capable of burning a wide range of coals, best ability to follow fluctuating loads, high fly ash carry over, low load smoke.
- Stationary and dumping grate	20,000-80,000	450,000	
- Travelling grate	100,000-400,000	750,000	
- Vibrating grate	20,000-100,000	400,000	
2. Overfeed			Characteristics similar to vibrating-grate stokers except these stokers experience difficulty in burning strongly caking coals
- Chain grate and travelling grate	20,000-100,000	600,000	
- Vibrating grate	30,000-150,000	400,000	Low maintenance, low fly ash carry over, capable of burning wide variety of weakly caking coals, smokeless operation over entire range.
3. Underfeed			Capable of burning caking coals and a wide range of coals (including anthracite), high maintenance, low fly ash carry over, suitable for continuous-load operation.
- Single or double retort	20,000-30,000	400,000	
- Multiple retort			

a/ pph = pounds steam/hr; 1 pph = 1000 Btu/hr.

b/ Maximum amount of Btus consumed per hour for each square foot of grate in the stoker.

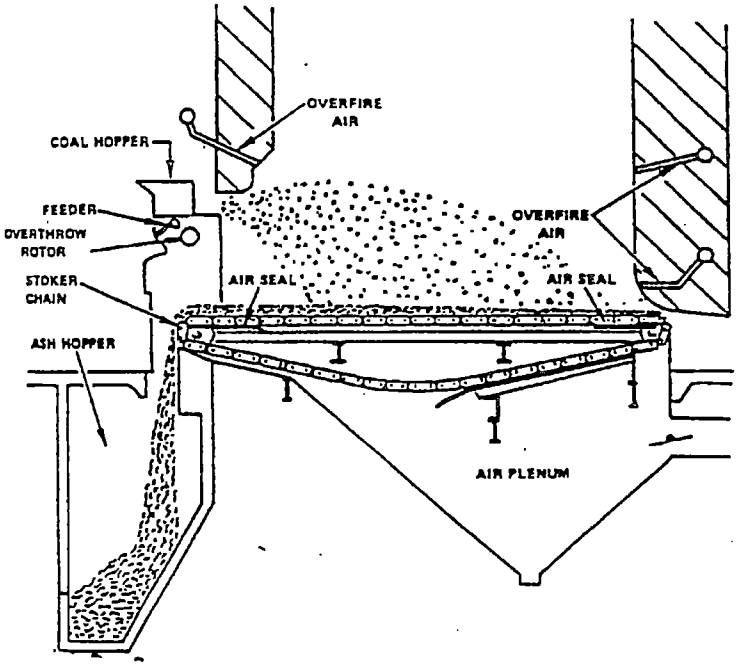
Source: Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, NY, 1981.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 61 of 223

2-31

EXHIBIT 2-15

DIAGRAM OF A SPREADER STOKER



Source: Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, NY, 1981.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 62 of 223

EXHIBIT 2-16

TOTAL COAL BOILER CAPACITY BY EPA REGION
(%)

EPA Region	Pulverizers		Cyclone	Stoker	Other a/	Total
	Dry Bottom	Wet Bottom				
1	69.2	11.3	16.7	0.0	2.8	100.0
2	60.6	19.4	5.0	2.7	12.2	100.0
3	87.6	0.3	2.8	0.0	9.2	100.0
4	71.6	5.3	5.2	0.1	17.7	100.0
5	70.4	4.9	14.0	0.5	10.1	100.0
6	48.6	12.5	0.0	0.0	38.9	100.0
7	58.3	3.5	19.2	1.0	18.0	100.0
8	60.3	5.4	10.6	1.1	22.5	100.0
9	77.5	0.0	0.0	0.0	22.5	100.0
10	100.0	0.0	0.0	0.0	0.0	100.0
U.S. Total	69.3	5.3	8.3	0.4	16.7	100.0

a/ Includes unknown, or other boiler types.

Source: ICF Coal and Utilities Information System Database.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 63 of 223

EXHIBIT 2-17

AVERAGE COAL BOILER SIZE BY TYPE OF BOILER
AND BY EPA REGION
(MW)

EPA Region	Pulverizers		Cyclone	Stoker
	Dry Bottom	Wet Bottom		
1	210.2	102.7	228.0	N/A
2	127.8	137.7	143.5	39.0
3	297.6	136.0	195.3	N/A
4	249.3	147.4	342.6	14.6
5	185.0	117.0	222.6	11.2
6	522.7	489.0	N/A	N/A
7	162.5	148.3	243.2	12.3
8	234.2	141.7	322.8	17.9
9	388.3	N/A	N/A	N/A
10	610.0	N/A	N/A	N/A
U.S. Total	231.8	162.9	243.2	14.0

N/A = Not applicable.

Source: ICF Coal and Utilities Information System Database.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 64 of 223

These impurities are typically referred to as "ash", whether the reference is to some of the constituents that compose the coal itself prior to combustion or the waste products that result from its combustion. Some coal ash is inherent to the coal seam, while other ash comes from non-coal strata near the coal seam which are intermixed during mining. The coal consumed by electric utilities is generally over 10 percent ash.[24] At current rates of coal consumption, about 70 million tons of ash pass through coal-fired power plants each year.[25]

The ash generated at utility power plants is produced inside the boiler furnace from the inorganic components as the organic components of the coal combust. The types of ash produced can vary -- some ash is swept through the furnace with the hot flue gases to form fly ash, while some settles to the bottom of the boiler as bottom ash or slag. The amount of each type of ash produced depends upon the boiler configuration as described in Section 2.3 and the characteristics of the coal (see Chapter Three for further discussion of ash types).

Air quality regulations have long restricted the amount of fly ash that may be released through a power plant's stacks. Primarily through the use of electrostatic precipitators or bag houses, power plants collect fly ash particles, leaving the flue gases nearly particulate-free as they are emitted from the stack. As a result, the fly ash, bottom ash, and slag that is collected during and after combustion is approximately equal to the amount of ash in the coal prior to combustion.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 65 of 223

For many power plants constructed since the 1970's, additional environmental controls also require that a portion of the sulfur oxides be removed from the flue gases. The dominant technology for removing sulfur oxides is known as flue gas desulfurization (FGD), in which alkaline agents, usually in liquid slurry form, are mixed with the flue gases to convert the sulfur into non-gaseous compounds. The resulting waste product is generally referred to as FGD sludge and can amount to 25 percent or more of the volume of coal consumed at a given plant.[26] In total, U.S. coal-fired power plants produce about 85 million tons of ash and FGD sludge per year. By the end of the century, this volume is expected to approximately double.

Exhibit 2-18 shows the number of coal-fired utility power plants and units that produce FGD wastes in each EPA region as of 1985. Regions 6, 8, and 9 have the highest proportion of both plants and units producing FGD wastes. For example, more than half of the coal-fired units in region 9 produce FGD wastes. The high proportion of FGD-producing plants in these regions is in part attributable to the fact that many of the coal-fired plants in these regions are relatively new and were required to incorporate scrubbers to meet air emission regulations.

Plants and units producing FGD waste represent a smaller percentage in other regions, primarily because these regions relied on coal-fired capacity for a major portion of their generation before units with FGD technology were installed. For example, the absolute number of both plants and units producing FGD waste is greatest in Region 4, reflecting this area's reliance on coal for generating electricity.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 66 of 223

EXHIBIT 2-18

ELECTRIC UTILITY PRODUCTION OF FGD WASTES: 1985

EPA Region	# of Plants Producing FGD waste	Percent of Plants Producing FGD Wastes	# of Units Producing FGD Wastes	Percent of Units Producing FGD Wastes
1	0	0.0	0	0.0
2	3	17.6	3	7.9
3	5	8.8	13	9.4
4	11	12.0	26	9.8
5	10	5.8	16	3.6
6	8	20.5	23	35.9
7	6	9.1	11	7.9
8	9	18.8	25	29.4
9	3	23.1	12	57.1
10	0	0.0	0	0.0
Total U.S.	55	12.0	129	14.4

Source: Utility Data Institute Power Statistics Database.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 67 of 223

Regions 1 and 10, at the other extreme, have no plants or units producing FGD wastes. These regions (New England and the Pacific Northwest) are not highly dependent upon coal and consequently, have relatively few coal-fired plants.

Numerous other types of wastes are produced during normal operation and maintenance at coal-fired power plants. These include, among others, boiler blowdown, coal pile runoff, cooling tower blowdown, demineralizer regenerants and rinses, metal and boiler cleaning wastes, pyrites, and sump effluents. These wastes are usually small in volume relative to ash and FGD sludge, but because they may have higher concentrations of certain constituents that may cause environmental concern, they also require care in handling and disposal. All of these wastes are discussed in greater detail in Chapter Three.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 68 of 223

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 69 of 223

CHAPTER TWO

NOTES

[1] Edison Electric Institute, 1985 Statistical Yearbook.

[2] Energy Information Administration, Annual Energy Outlook 1985, DOE/EIA-0383(85), p. 50.

[3] A gigwatt-hour (Gwh) is one million kilowatt-hours; a kilowatt-hour is the amount of electricity generated by 1 kilowatt of electric generating capacity operating for one hour.

[4] Energy Information Administration, Annual Outlook for U.S. Electric Power, DOE/EIA-0474(86), 1986.

[5] Ibid.

[6] Ibid.

[7] Ibid.

[8] Ibid.

[9] Ibid.

[10] Ibid.

[11] Ibid.

[12] Ibid.

[13] Ibid.

[14] Ibid.

[15] Ibid.

[16] The major portion of this discussion is taken from Annual Outlook for U.S. Electric Power, DOE/EIA, 1986. See this document for further information.

[17] Ibid., page 5.

[18] Ibid.

[19] Ibid.

[20] Ibid.

[21] Energy Information Administration, Electric Power Annual 1984, DOE/EIA-0348(84), p. 24.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 70 of 223

[22] Energy Information Administration, Electric Power Monthly, DOE/EIA-0226(85/12), December 1985, p. 21.

[23] For more detail, see Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, New York, 1981, pp. 378-431.

[24] Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1984, DOE/EIA-0191(84), July 1985, p. 6.

[25] American Coal Ash Association.

[26] For example, a coal with 2 percent sulfur would produce approximately 80 pounds sulfur dioxide per ton of coal consumed. A limestone scrubber capturing 90 percent of the sulfur dioxide, assuming a stoichiometric ratio of 1.4 and a sludge moisture content of 50 percent, would product almost 500 pounds of FGD sludge per ton of coal consumed. See Appendix B for a detailed discussion of the methodologies used to determine this calculation.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 71 of 223

CHAPTER THREE

WASTES GENERATED FROM COAL-FIRED ELECTRIC UTILITY POWER PLANTS

As part of EPA's responsibility under Section 8002(n) of RCRA, Congress directed that the study of wastes from the combustion of fossil fuels should include an analysis of "the source and volumes of such material generated per year." In response to this directive, this chapter examines the physical and chemical characteristics of the types and quantities of wastes that are generated currently and likely to be generated in the future.

3.1 OVERVIEW OF ELECTRIC UTILITY WASTES

As discussed initially in Chapter Two, the noncombustible material that remains after coal is burned is called ash. The proportion of noncombustible material in coal is referred to as the ash content. There are four basic types of wastes that can be produced directly from coal combustion: fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) sludge. The smaller ash particles entrained by the flue (exhaust) gas are referred to as fly ash and are produced in varying degrees by all plants. Larger ash particles that settle on the bottom of the boiler will form either bottom ash (if the particles have never completely melted) or boiler slag (if the ash particles have melted), depending on the furnace design. Another waste product, called FGD sludge, is generated when some of the sulfur dioxide (formed when the sulfur present in the coal combines with oxygen during combustion) is removed from other flue gases. This removal process is required by the Clean Air Act Amendments of 1979, which revised the New Source

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 72 of 223

Performance Standards for any electric utility boiler constructed after September 1978. These plants are required to remove 90 percent of the sulfur dioxide, which is usually accomplished with a flue gas desulfurization (FGD, or scrubber) system. Because they are generated in very large quantities, these four waste materials -- fly ash, bottom ash, boiler slag, and FGD sludge -- are referred to by the industry as high-volume wastes. This term will be used throughout this study to be consistent with the terminology that is commonly used for these wastes.

Electric utility power plants also generate waste streams that the industry typically calls low-volume wastes, which are formed during equipment maintenance and water purification processes. Types of low-volume wastes generated by coal-fired power plants include boiler blowdown, coal pile runoff, cooling tower blowdown, demineralizer regenerants and rinses, metal and boiler cleaning wastes, pyrites, and sump effluents. Because it is common industry terminology, the term "low-volume wastes" will be used throughout this report; however, some of these wastes (such as cooling tower blowdown) can be generated in substantial quantities, although generally in smaller quantities than high-volume wastes.

The remainder of this chapter describes each type of high-volume and low-volume waste stream, the various methods of collection used for each, the volumes produced, and the physical and chemical characteristics that determine the waste's behavior during disposal and its potential to leach.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 73 of 223

3.2 HIGH-VOLUME WASTES

High-volume coal combustion utility wastes are those waste streams generated in the boiler furnace -- fly ash, bottom ash, and boiler slag -- and in the cleaning of coal combustion flue gas. The following sections describe the volumes and the physical and chemical characteristics of these high-volume waste streams.

3.2.1 Ash

The noncombustible waste material that remains after coal is burned is referred to as ash. Some noncombustible materials are characteristic of the coal itself, originating from the chemical elements in the plants from which the coal was formed. These materials generally account for no more than two percent of the ash content of the coal. Other noncombustible materials extraneous to the coal, such as minerals lodged in the coal seam during or after its geologic formation and rocks near the coal seam that are carried away with the coal during mining, are burned during the fuel combustion process along with the coal itself. These materials account for most of the ash content.

3.2.1.1 How Ash is Generated

The type of ash produced from a boiler is determined by the type of coal that is burned and the design of the boiler furnace. As discussed in Chapter Two, the major types of boilers used by electric utilities are wet-bottom pulverizers, dry-bottom pulverizers, cyclone-fired boilers, and stokers.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 74 of 223

Pulverizers are the most widely used boilers in the electric utility industry because they can burn many different types of coal. Due to the very fine consistency of the coal after it is pulverized, the ash particles are easily carried out of the boiler along with the flue gases, resulting in a relatively large proportion of fly ash.

The amount of fly ash that accumulates in a pulverizer depends on whether it is dry-bottom or wet-bottom.[1] In dry-bottom pulverizers, which constitute the majority of electric utility boilers, ash particles in the coal generally do not melt during the combustion process because the ash fusion temperature (i.e., the melting point) is higher than the operating temperature in the boiler. In dry-bottom pulverizers, therefore, about 80 percent of the fine ash remains in the flue gas as fly ash. The remaining ash settles to the bottom of the boiler (hence the term bottom ash) where it is collected at a later time. In wet-bottom pulverizers, about 50 percent of the ash exits the boiler as fly ash, while the other 50 percent remains in the furnace. However, ash particles that remain in wet-bottom pulverizers become molten; this boiler slag remains in a molten state until it is drained from the boiler bottom.

Cyclone-fired boilers burn larger-sized coal particles than do pulverizers, since partial crushing is the only preparation required prior to injection into the furnace. The amount of fly ash that is generated in a cyclone boiler is less than that generated in a pulverizer because of the larger-sized coal particles and the design of the cyclone boiler. Because the air circulation within the boiler furnace is designed to create a cyclone-like

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 75 of 223

vortex, the coal particles have a tendency to contact the boiler walls. The operating temperature is high enough to melt the ash so that it adheres to the furnace walls as liquid slag. Excess slag continually drains to the bottom of the furnace, where it is removed for disposal. Only 20 to 30 percent of the ash formed in a cyclone boiler leaves the boiler as fly ash.

A few older and smaller power plants have stoker-type boilers, in which coal is burned on or immediately over a grate in the furnace. Stokers are designed to burn coals that do not contain too many small particles (fines), which can tend to smother the fire. Because there are fewer small particles, the amount of fly ash is reduced. For example, in a spreader stoker, the most common type of stoker boiler, the coal is uniformly fed over the fire in a manner that enables suspension burning of the finer pieces, while heavier pieces of coal fall onto the grate for further combustion. The large amount of coal that is burned on the grate reduces the amount of fly ash; the ash produced in a spreader stoker is generally about 50 percent fly ash and 50 percent bottom ash.

3.2.1.2 Methods of Ash Collection

As the flue gas leaves the boiler, it is passed through a mechanical ash collector to remove some of the fly ash particles. A mechanical ash collector operates by exerting centrifugal force on the fly ash particles, throwing them to the outside wall of the collector where they can be removed. These collectors are effective mainly for capturing the larger fly ash particles. To remove the smaller particles, the flue gas must then pass through some

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 76 of 223

other type of particulate control device, such as an electrostatic precipitator, a baghouse, or a wet scrubber.

The electrostatic precipitator (ESP) is the most common device for fine ash collection. ESPs operate by applying an electrical charge to the fly ash particles. In the presence of an intense electrical field, the charged particles are attracted to a grounded collection electrode. The collected dust is then discharged to a storage hopper by a process called rapping that dislodges the collected particles. ESPs are most efficient when coal with high sulfur content is used because the sulfur dioxide in the flue gas helps retain the electrical charge. When properly designed and maintained, an ESP is capable of collecting over 99 percent of the ash present in the flue gas.[2]

When coal with lower sulfur content is burned, baghouses (also called fabric filters) are often more appropriate to use as fly ash collection devices. If operated efficiently, they also can remove over 99 percent of the ash from the flue gas.[3] In this system, the flue gas passes through a filter that traps the ash particles. The ash builds up on the filter, forming a filter cake. As this process continues, the ash collection efficiency tends to increase as it becomes more difficult for particles to pass through the filter material. Periodically, the cake is dislodged from the filters, which reduces efficiency until buildup occurs again.

Some power plants remove fly ash by the wet scrubbing method, in which liquids are used to collect the ash. In one method, the ash particles are removed from the flue gas stream by contacting them with a scrubbing liquid in a spray tower. This process forms an ash slurry, which is then discharged.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 77 of 223

Alternatively, fly ash particles may be dislodged from the walls of the scrubber by a liquid flushing of the scrubber. Because the operation of a scrubber is very plant-specific, the collection efficiency of wet scrubbers varies, though wet scrubbers are generally not as efficient as ESPs and baghouses. The advantage of wet scrubbers, however, is that they can also be used simultaneously to collect sulfur oxides from the flue gas system.

Ash particles that do not escape as fly ash become bottom ash or boiler slag. In dry-bottom pulverizers and stokers, the temperatures are low enough to allow the molten ash to cool and reform into dry, solid ash particles, or bottom ash. In smaller boilers of this type, the ash falls onto a grate, which then is opened, allowing the ash to drop into a flat-bottom hopper. The large quantities of bottom ash produced in larger boilers often require hoppers with sloped sides for self-feeding. Some hoppers may contain water to quench the ash and to facilitate disposal.

In cyclone-fired boilers and wet-bottom pulverizers, the liquified ash particles that fall to the bottom of the boiler during combustion remain in a molten state and coalesce into large masses (called slag), which then drop onto the boiler floor. The slag is tapped into a water-filled hopper, or slag tank, which is periodically emptied and the slag disposed. Slag tanks for cyclone-fired boilers are similar to those used for pulverizers but have a higher relative capacity because a greater percentage of the ash in cyclones becomes boiler slag.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 78 of 223

3.2.1.3 Quantities of Ash Generated

Nearly all of the noncombustible material in coal ends up as fly ash, bottom ash, or boiler slag. As mentioned earlier, the coal industry and the electric utility industry refer to this material as a coal's ash content. As a result, the volume of ash generated is directly related to the amount of coal consumed and the ash content of the coal. The ash content of coal will vary according to several factors, including coal-producing region, coal rank (i.e., bituminous, subbituminous, anthracite, or lignite), mine, seam, and production method. Although the proportion of ash in coal may range from 3 to 30 percent, the industry-wide average for electric utility power plants is 10.1 percent.[4] Exhibit 3-1 shows the average ash content of coal that was delivered to coal-fired power plants in 1985 for some of the major coal-producing regions.

In 1984, electric utilities generated about 69 million tons of coal ash. Ash generation is expected to increase considerably, to about 120 million tons in the year 2000, an increase of about 72 percent over 1984 levels. This increase can primarily be attributed to the increase in the demand for coal by electric utilities. While there is some uncertainty over the amount of coal that will be consumed by electric utility power plants, coal-fired electricity generation is likely to increase significantly. For example, one estimate indicates that by the year 2000 electric utility power plants will burn over one billion tons of coal to meet 61 percent of total electricity demand,[5] an increase of 70 percent over the 664 million tons consumed in 1984.[6] Exhibit 3-2 shows historical and forecasted future ash generation by coal-fired electric power plants.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 79 of 223

EXHIBIT 3-1

REPRESENTATIVE ASH CONTENTS BY PRODUCING REGION AND COAL RANK: 1985

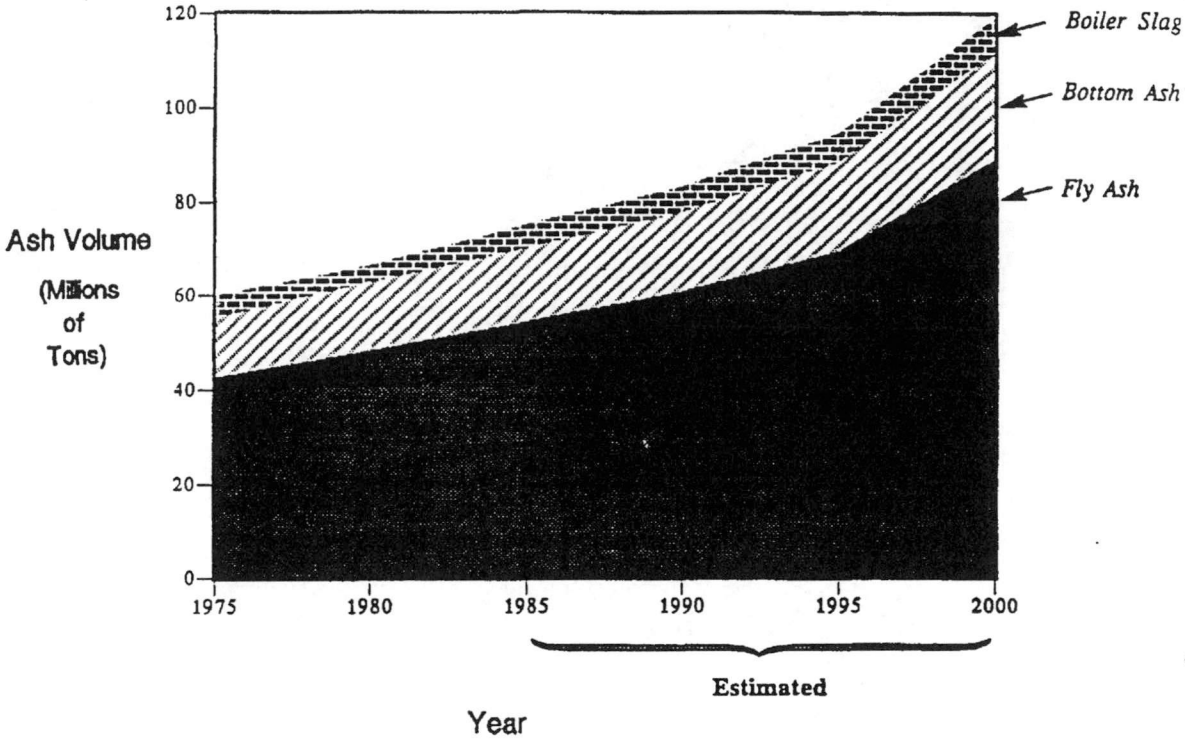
Coal Rank and Region	Percent Ash
Anthracite	
Northeastern Pennsylvania	29.4
Bituminous	
Western Pennsylvania	10.9
Northern West Virginia	10.4
Ohio	11.3
Eastern Kentucky	9.9
Alabama	12.2
Illinois	9.7
Colorado	6.2
Utah	9.4
Arizona	8.9
Subbituminous	
Wyoming	5.9
New Mexico	18.8
Lignite	
Texas	15.8
North Dakota	9.0
U.S. Average	10.1

Source: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1985, DOE/EIA-0191(85), July 1986.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 80 of 223

EXHIBIT 3-2

VOLUME OF ASH GENERATED BY COAL-FIRED
ELECTRIC UTILITY POWER PLANTS
1975 - 2000



Sources: 1975-1984: American Coal Ash Association.
1985-2000: ICF Incorporated. See Appendix B for in-depth discussion of the methodologies used to develop these estimates.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 81 of 223

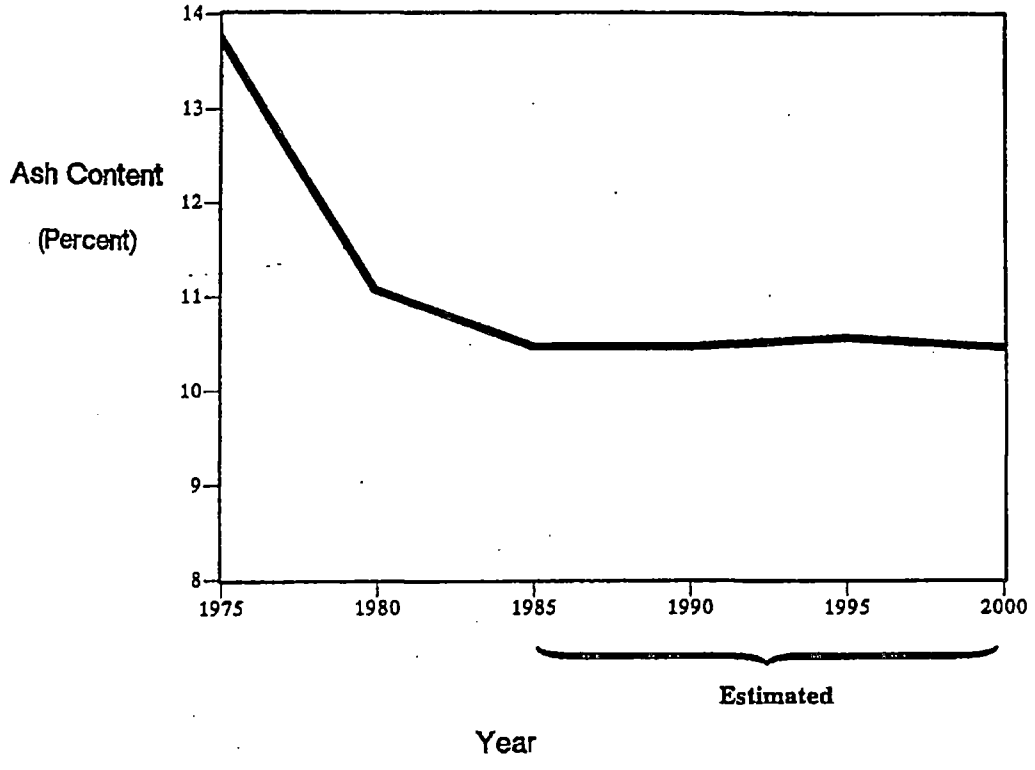
The average ash content of coal burned by electric utilities has declined from about 14 percent to slightly more than 10 percent over the past decade (see Exhibit 3-3). To meet particulate emission standards and to lower certain operating and maintenance costs, more electric utilities are now choosing to burn coal with lower ash contents. Although some coals are naturally low in ash, producers and/or utilities can also reduce ash content by cleaning the coal.[7] In some cases, cleaning can reduce ash content by as much as 50 to 70 percent. At present, utilities clean about 35 percent of all the coal they consume; most of the coal that is cleaned comes from eastern and midwestern underground bituminous coal-mining operations. Another reason for the increased use of coal with lower average ash content is the growth in Western coal production, particularly in the Powder River Basin area of Montana and Wyoming. These coals are naturally low in ash content, and little ash is extracted during the mining process.

The quantity of fly ash and bottom ash produced is likely to increase faster over time than the quantity of boiler slag because most new coal-fired plants will employ dry-bottom pulverizer boilers, which generate fly ash and bottom ash rather than boiler slag. Because dry-bottom pulverizers are capable of burning coal with a wide range of ash fusion temperatures,[8] they are able to burn a greater variety of coals compared with cyclone boilers and wet-bottom pulverizers. Another advantage of dry-bottom pulverizers is that they produce less nitrogen oxide emissions than do other boiler types, which enables electric utilities to meet requirements for nitrogen oxide emissions control more easily.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 82 of 223

EXHIBIT 3-3

**AVERAGE ASH CONTENT OF COAL BURNED
BY ELECTRIC UTILITY POWER PLANTS IN THE U.S.
1975 - 2000**



Source: 1975-1984: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants.

1985-2000: ICF Incorporated. See Appendix B for in-depth discussion of the methodologies used to develop these estimates.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 83 of 223

3.2.1.4 Physical Characteristics of Ash

The physical characteristics of coal combustion ash of interest are particle size and distribution, compaction behavior, permeability, and shear strength. Exhibit 3-4 provides representative ranges of values for these characteristics of fly ash, bottom ash, and boiler slag.

The greater the assortment of particle sizes in the material, the more it can be compacted to achieve greater density and shear strength and lower permeability. Generally, fly ash is similar in size to silt. Most fly ash particles are between 5 and 100 microns in diameter; within a single sample, the largest particles may be 200 times larger than the smallest particles.[9] The size of bottom ash and boiler slag particles can range from that of fine sand to fine gravel, or about 0.1 to 10 millimeters.[10]

Compaction behavior refers to the amount of settling that takes place after disposal and the rate at which such settling occurs. Compressibility, density, and moisture content are factors affecting compaction behavior.[11] When compacted and dry, most fly ash and bottom ash behave very similarly to cohesive soil.

Permeability reflects the rate at which water will seep through the waste material in a given period of time and provides a good first estimate of the rate and quantity of leachate migration. A number of factors can influence the degree of permeability, such as the size and shape of the waste particles, the degree of compaction, and the viscosity of the water. Properly compacted fly ash often has low permeability, similar to that of clay, while the

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 84 of 223

EXHIBIT 3-4

REPRESENTATIVE RANGES OF VALUES FOR THE PHYSICAL CHARACTERISTICS OF FLY ASH, BOTTOM ASH, AND BOILER SLAG

	Fly Ash	Bottom Ash/ Boiler Slag
Particle Size (mm)	0.001-0.1	0.1-10
Compaction Behavior:		
Compressibility (%)	1.8	1.4
Dry Density (lbs/ft^3)	80-90	80-90
Permeability (cm/sec)	10^{-6}-10^{-4}	10^{-3}-10^{-1}
Shear Strength		
Cohesion (psi)	0-170	0
Angle of Internal Friction (^{o})	25-45	25-45

Sources: For compressibility values, Arthur D. Little, Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, Volume I, Prepared for U.S. Environmental Protection Agency, June 1985, p. 3-29. For other values, Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, p. 3-3 - 3-8.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 85 of 223

permeability of bottom ash is usually slightly higher. Boiler slag is higher still, having a permeability comparable to that of fine gravel.

Shear strength is an important determinant of the shape and structural stability of wastes disposed in landfills; a strong material (i.e., one with high shear strength) can form steep slopes and support heavy loads from above. Two indicators of shear strength are cohesion, a measure of the attraction between particles due to electrostatic forces, and the angle of internal friction, an indicator of the friction between particles. Dry, nonalkaline ash has no cohesion. Dry ash that is alkaline demonstrates some cohesion and, when compacted, increases in strength over time. The angle of internal friction associated with ash varies with the degree of compaction, although it is similar to that for clean, graded sand.

3.2.1.5 Chemical Characteristics of Ash

The chemical composition of ash is a function of the type of coal that is burned, the extent to which the coal is prepared before it is burned, and the operating conditions of the boiler. These factors are very plant- and coal-specific.

In general, over 95 percent of ash is made up of silicon, aluminum, iron, and calcium in their oxide forms. Magnesium, potassium, sodium, and titanium are also present to a lesser degree. Exhibit 3-5 shows the concentration of these major elements typically found in fly ash, bottom ash, and boiler slag.

Ash also contains many other elements in much smaller quantities. The types and proportions of these trace elements are highly variable and not

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 86 of 223

EXHIBIT 3-5

LOW AND HIGH CONCENTRATIONS OF MAJOR CHEMICAL CONSTITUENTS FOUND IN ASH GENERATED BY COAL-FIRED POWER PLANTS (parts per million)

	Fly Ash		Bottom Ash/Boiler Slag	
	Low	High	Low	High
Aluminum	11,500	144,000	88,000	135,000
Calcium	5,400	177,100	8,400	50,600
Iron	7,800	289,000	27,000	203,000
Magnesium	4,900	60,800	4,500	32,500
Potassium	1,534	34,700	7,300	15,800
Silicon	196,000	271,000	180,000	273,000
Sodium	1,180	20,300	1,800	13,100
Titanium	400	15,900	3,300	7,210

Source: Utility Solid Waste Activities Group, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, Appendix A, Submitted to the U.S. Environmental Protection Agency, October 26, 1982, p. 31.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 87 of 223

readily categorized. Concentrations for various trace elements in coal ash are shown in Exhibit 3-6, which indicates the potential range of values and median concentration for such trace elements for coals from different regions of the U.S. A summary of how the concentration of elements in ash varies according to coal source is shown in Exhibit 3-7. For example, Eastern and Midwestern coal ashes usually contain greater amounts of arsenic, selenium, chromium, and vanadium than do Western coal ashes, while Western coals have larger proportions of barium and strontium. Coal mining and cleaning techniques can reduce the amount of trace elements that are ultimately found in the ash after combustion. For example, in some cases, coal cleaning can remove more than half of the sulfur, arsenic, lead, manganese, mercury, and selenium that is contained in the coal prior to combustion.

The proportions of elements contained in fly ash, bottom ash, and boiler slag can vary. Exhibit 3-8 provides ranges and median values for element concentrations in different types of ash -- bottom ash and/or boiler slag, and fly ash. The concentrations of elements formed in fly ash are shown for two types -- the larger particles removed from the flue gas by mechanical collection and the smaller particles removed with an electrostatic precipitator or a baghouse (see Section 3.2.1.2 for more detail on methods of ash collection). For example, much higher quantities of arsenic, copper, and selenium are found in fly ash than are found in bottom ash or boiler slag. The distribution of elements among the different types of ash is largely determined by the firing temperature of the boiler relative to the coal's ash fusion temperature, which in turn affects the proportions of volatile elements that end up in fly ash and bottom ash. Some elements, such as sulfur, mercury, and chlorine, are almost completely volatilized and leave the boiler

EXHIBIT 3-6

ELEMENT CONCENTRATIONS IN ASH FROM THREE GEOGRAPHIC SOURCES
(milligrams per kilogram)*

	Eastern Coal		Midwestern Coal		Western Coal	
Element	Range	Median	Range	Median	Range	Median
Arsenic	2.0-279	75	0.50-179	54	1.3-129	18
Barium	52-2200	892	300-4300	905	300-5789	2700
Boron	10.0-580	121	10-1300	870	41.9-1040	311
Cadmium	0.10-8.24	1.59	0.50-18	2.6	0.10-14.3	1.01
Chromium	34-437	165	70-395	172	3.4-265	45
Cobalt	6.22-79	40.6	19-70	35.7	4.9-69	13.0
Copper	3.7-349	136	20-330	125	29-340	74.8
Fluorine	0.40-89	8.8	3.2-300	75	0.40-320	50.1
Lead	1.3-222	18.0	3.0-252	149	0.40-250	26.1
Manganese	79-430	190	194-700	410	56.7-769	194
Mercury	0.02-4.2	0.192	0.005-0.30	0.044	0.005-2.5	0.067
Molybdenum	0.84-51	15.0	7.0-70	43	1.4-100	12.0
Nickel	6.6-258	78	26-253	121	1.8-229	38.0
Selenium	0.36-19.0	8.05	0.08-19	7.0	0.13-19.0	4.1
Silver	0.25-8.0	0.695	0.10-1.20	0.39	0.040-6.0	0.26
Strontium	59-2901	801	30-2240	423	931-3855	2300
Thallium	7.0-28.0	25.0	2.0-42	16.0	0.10-3.50	1.06
Vanadium	110-551	269	100-570	270	11.9-340	94
Zinc	16-1420	163	20-2300	600	4.0-854	71

* Values shown are for all types of ash combined.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 88 of 223

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 89 of 223

EXHIBIT 3-7

EFFECT OF GEOGRAPHIC COAL SOURCE ON ASH ELEMENT CONCENTRATION

Element	Concentration Pattern
Arsenic	low in western coal ash; eastern and midwestern coal ashes indistinguishable
Barium	highest in western coal ash
Cadmium	most concentrated in midwestern coal ash
Chromium	low in western coal ash; eastern and midwestern coal ashes indistinguishable
Mercury	highest in eastern coal ash; all distributions highly skewed toward high concentrations
Lead	highest in midwestern coal ash
Selenium	similar in eastern and midwestern coal ash; lower in western coal ash
Strontium	greater in eastern than in midwestern coal ash; greater still in western coal ash
Vanadium	similar in eastern and midwestern coal ash; lower in western coal ash
Zinc	greater in eastern than in western coal ash; greater still in midwestern coal ash

Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983, p. 3-30.

EXHIBIT 3-8

ELEMENT CONCENTRATIONS IN THREE TYPES OF ASH
(milligrams per kilogram)

	Bottom Ash/Boiler Slag		Fly Ash			
			Mechanical Hopper Ash		Fine Fly Ash	
Element	Range	Median	Range	Median	Range	Median
Silver	0.1-.51	0.20	0.08-4.0	0.70	0.04-8.0	0.501
Arsenic	.50-168	4.45	3.3-160	25.2	2.3-279	56.7
Boron	41.9-513	161	205-714	258	10.0-1300	371
Barium	300-5789	1600	52-1152	872	110-5400	991
Cadmium	0.1-4.7	0.86	0.40-14.3	4.27	0.10-18.0	1.60
Cobalt	7.1-60.4	24	6.22-76.9	48.3	4.90-79.0	35.9
Chromium	3.4-350	120	83.3-305	172	3.6-437	136
Copper	3.7-250	68.1	42.0-326	130	33.0-349	116
Fluorine	2.5-104	50.0	2.50-83.3	41.8	0.40-320	29.0
Mercury	0.005-4.2	0.023	0.008-3.00	0.073	0.005-2.50	0.10
Manganese	56.7-769	297	123-430	191	24.5-750	250
Lead	0.4-90.6	7.1	5.2-101	13.0	3.10-252	66.5
Selenium	.08-14	0.601	0.13-11.8	5.52	0.60-19.0	9.97
Strontium	170-1800	800	396-2430	931	30.0-3855	775
Vanadium	12.0-377	141	100-377	251	11.9-570	248
Zinc	4.0-798	99.6	56.7-215	155	14.0-2300	210

Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983, p. 3-24.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 90 of 223

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 91 of 223

in the flue gas rather than remaining in the bottom ash or boiler slag. Some of these more volatile elements may condense on the surface of the fly ash particles as the flue gas cools.

3.2.2 FGD Sludge

Another waste stream often generated in large volumes by coal-fired utility power plants is FGD sludge, which is created when utilities remove sulfur oxides from the flue gases. Emissions of sulfur oxides in the flue gases are due to the oxidation of sulfur during coal combustion. State and Federal regulations require power plants to control the amount of sulfur oxides released through the stack. To meet the applicable requirements most power plants use coals whose inherent sulfur content is low. If the sulfur content is so low that additional sulfur dioxide removal is not needed, then FGD sludge is not produced.

Present requirements for all new coal-fired plants, however, not only limit the amount of sulfur oxides that can be emitted, but also mandate a percentage reduction in the amount of sulfur dioxide emissions.[12] This requirement will substantially increase the number of sulfur dioxide control systems in use. The primary method of sulfur dioxide control currently available is a flue gas desulfurization (FGD) system through which the flue gases pass before being emitted from the stack. The wastes produced by this system are called FGD (scrubber) sludge. Other methods of control include newer technologies such as fluidized bed combustion (FBC) and limestone injection multistage burners (LIMB).[13] The technical and economic feasibility of the latter two technologies are currently under evaluation by private industry and the U.S.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 92 of 223

Department of Energy. If these technologies do become more widely available, they also will produce substantial volumes of wastes.

3.2.2.1 Methods of FGD Sludge Collection

There are two major types of FGD (scrubber) systems. Non-recovery systems produce a waste material for disposal. Recovery systems produce recyclable by-products. Exhibit 3-9 illustrates the different types of FGD systems currently in use. Non-recovery systems, which account for 95 percent of the scrubber systems now in use by electric utilities, are further classified as wet or dry systems. In wet non-recovery scrubber systems, the flue gas contacts an aqueous solution of absorbents, thereby producing waste in a slurry form. The wastes generated by dry non-recovery systems contain no liquids.

Direct lime and limestone FGD systems are the most common wet non-recovery processes. With these systems, flue gases pass through a fly ash collection device and into a contact chamber where they react with a solution of lime or crushed limestone in the form of a slurry. The slurry circulates between the contact chamber and a separate reaction tank, where the reagents are added. From the reaction tank, the slurry is fed to a thickening and dewatering device to be prepared for disposal. After dewatering, the resulting liquid is recycled back to the reaction tank and the sludge solids are removed for disposal. Under certain conditions, direct lime and limestone scrubbers have been able to remove over 95 percent of the sulfur dioxide in the flue gas.[14]

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 93 of 223

EXHIBIT 3-9

MAJOR TYPES OF FLUE GAS DESULFURIZATION SYSTEMS

Non-Recovery		Recovery	
Wet	Dry	Wet	Dry
Direct Lime	Spray Drying	Wellman-Lord	Alumina/Copper* Sorbent
Direct Limestone	Dry Sorbent Injection*	Magnesium Oxide	Activated Carbon* Sorbent
Alkaline Fly Ash			
Dual-Alkali			

*Systems are currently in development and testing phases, and are not as yet being used commercially.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, pp. 4-1 - 4-4.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 94 of 223

A variation on the direct lime and limestone systems is the alkaline fly ash scrubber. Several western power plants that burn coal containing high-alkaline ash use these systems, which can improve sulfur dioxide removal. Rather than being collected by a separate upstream device (such as an ESP or baghouse), fly ash particles remain in the gas stream as it passes through the scrubber. In the scrubber, the alkaline fly ash, augmented with an alkaline lime/limestone slurry, acts to remove sulfur oxides. Alkaline fly ash scrubbers are not as efficient as direct lime and limestone systems, removing on average only about 40 percent of the sulfur dioxide.[15]

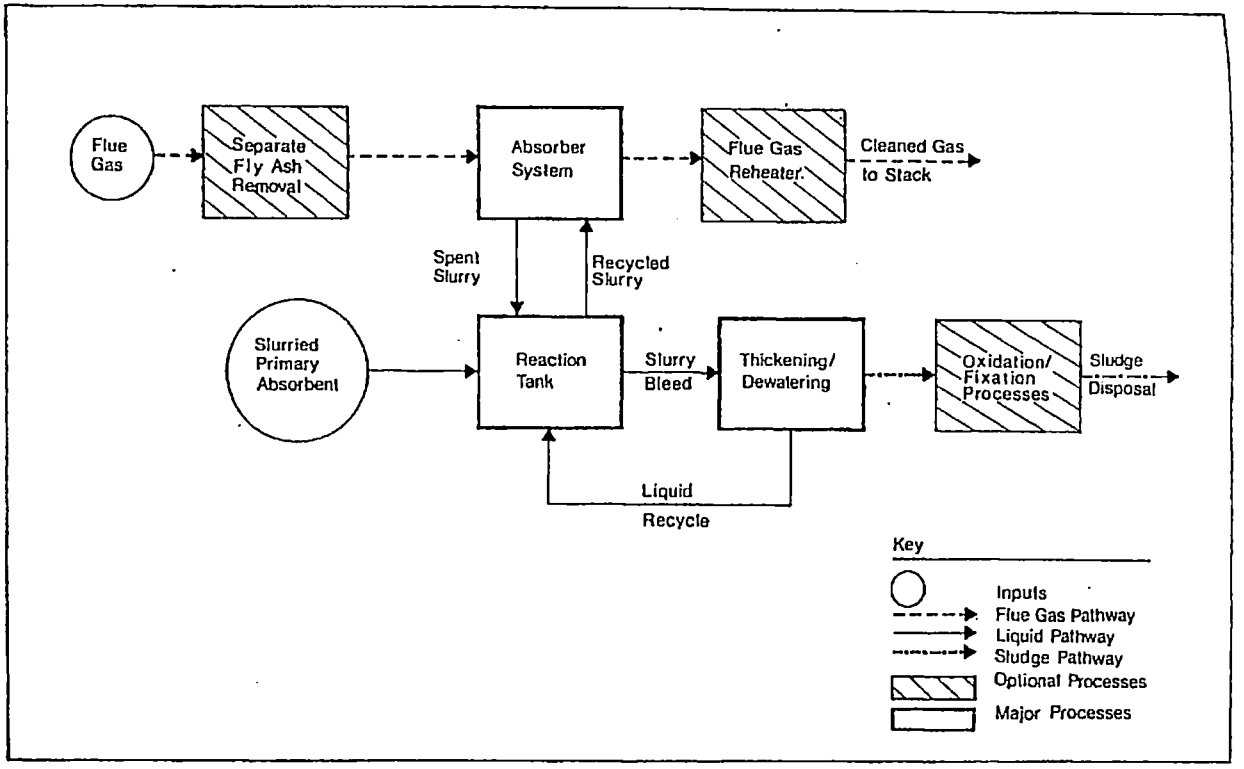
Another wet non-recovery system is the dual-alkali process. These scrubbers operate in much the same manner as the direct lime and limestone scrubbers. However, dual-alkali systems use a solution of sodium salts as the primary reagent to which lime is added for additional absorption. The soluble sodium salts are then recycled to the scrubber system and the insoluble portion of the slurry is left to settle so that it can be collected and disposed. Like direct lime and limestone systems, dual-alkali scrubbers remove up to 95 percent of the sulfur dioxide.[16]

Exhibit 3-10 presents a diagram of the operations of a wet FGD system. The flows shown for the flue gas, absorbent, slurry, and sludge are essentially the same for direct lime, direct limestone, alkaline fly ash, and dual-alkali systems.

At present, the two most popular methods of dry scrubbing under investigation are spray-drying and dry sorbent injection, although only the spray-drying process is now in commercial use at electric utility power plants.

EXHIBIT 3-10

FLOW DIAGRAM OF WET FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-3.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 95 of 223

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 96 of 223

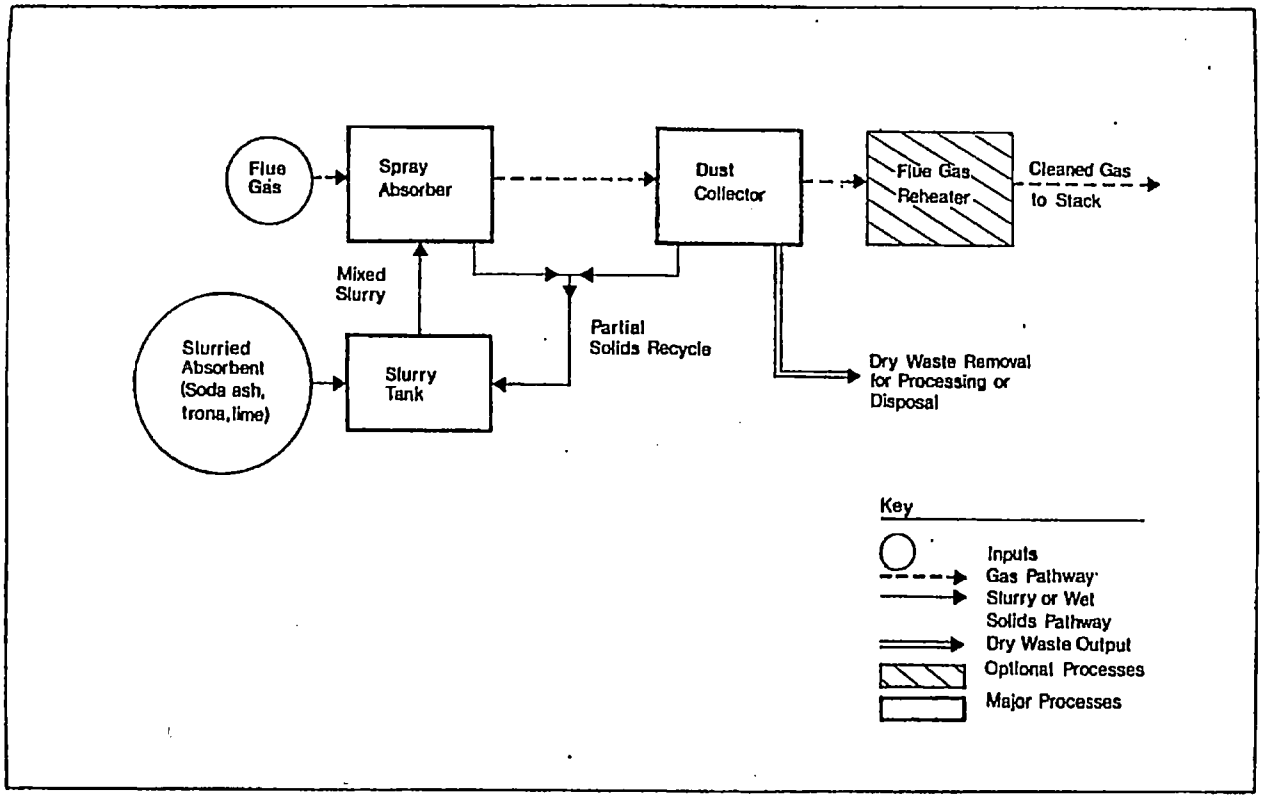
A flow diagram of a spray-drying system is presented in Exhibit 3-11. With this system, a fine spray of an alkaline solution is injected into the flue gas as it passes through a contact chamber, where the reaction with the sulfur oxides occurs. The heat of the flue gas evaporates the water from the absorbent solution, leaving a dry powder. This powder is then collected downstream of the contact chamber by a particulate collector, usually a baghouse. Spray-drying typically removes about 70 percent of the sulfur dioxide from the flue gas.[17] Because of the relatively low percentage reduction in sulfur dioxide achieved by spray-drying scrubbers compared with other scrubber technologies, this dry-scrubbing method is most commonly used for furnaces that burn lower sulfur coals.

Dry sorbent injection, illustrated schematically in Exhibit 3-12, is not yet used commercially by electric utilities, although one utility is designing a generating unit that will use this type of scrubber and which is due to begin operation by 1990.[18] This system involves the injection of a powdered sorbent, either nacholite or trona, into the flue gas upstream of a baghouse. Sulfur dioxide reacts with the reagent in the flue gas and on the surface of the filter in the baghouse. The dry wastes, which form a filter cake, are then removed during normal filter cleaning.

Dry injection offers several advantages over traditional wet scrubbing and spray-drying techniques: the required equipment is smaller and less expensive, no water is needed, flue gas reheating is not necessary, and sulfur dioxide and fly ash are removed simultaneously. Potential drawbacks of this process are the limited geographic availability of the sorbents and problems associated with waste disposal. For example, the waste tends to be very water soluble,

EXHIBIT 3-11

FLOW DIAGRAM OF SPRAY-DRYING FLUE GAS DESULFURIZATION SYSTEM

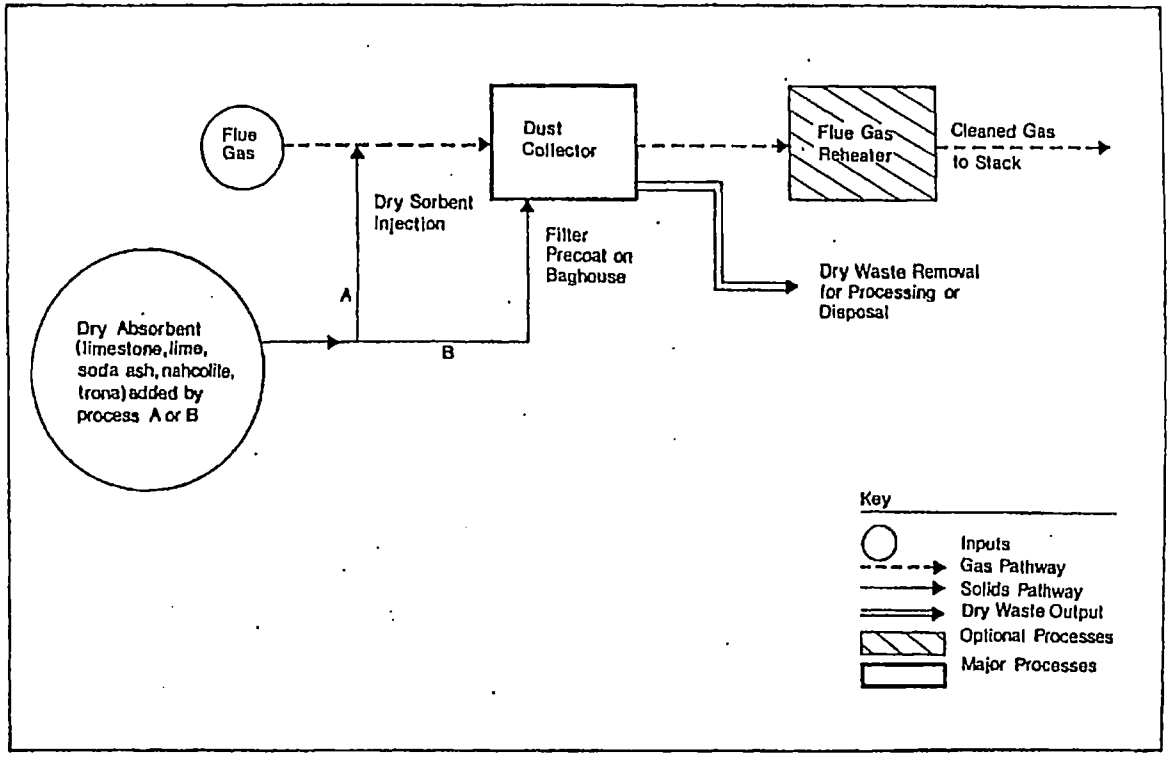


Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-5.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 97 of 223

EXHIBIT 3-12

FLOW DIAGRAM OF DRY INJECTION FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-6.

ELECTRONICALLY FILED - 2019 March 4 4:52 PM - SCPSC - Docket # 2018-318-E - Page 98 of 223