PLACE: Held via Videoconference REDACTED

DATE: Thursday, September 10, 2020

TIME: 9:00 A.M. - 12:30 P.M.

DOCKET NO.: E-7, Sub 1214

E-7, Sub 1213

E-7, Sub 1187

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-7, SUB 1214

Application of Duke Energy Carolinas, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

Noteworthy Reporting Services, LLC

DOCKET NO. E-7, SUB 1213

Petition of Duke Energy Carolinas, LLC,

for Approval of Prepaid Advantage Program

DOCKET NO. E-7, SUB 1187

Application of Duke Energy Carolinas, LLC,

for an Accounting Order to Defer Incremental Storm

Damage Expenses Incurred as a Result of Hurricanes

Florence and Michael and Winter Storm Diego

VOLUME 18

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T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

P R O C E E D I N G S

CHAIR MITCHELL: Good morning, everyone. It's 9:00. Let's go on the record, please.

Any preliminary matters to consider before we get started this morning?

MS. DOWNEY: Madam Chair, Dianna Downey.

CHAIR MITCHELL: Yes, Ms. Downey.

MS. DOWNEY: Good morning, Chair Mitchell and Commissioners. We're coming up on the Public Staff witnesses, and I wanted to make the Chair and the parties aware of a timing conflict related to one of our panels and just make a request. So that it's -- it's unlikely that we will reach Garrett and Moore today, but Mr. Moore is scheduled to appear at a hearing this afternoon, for just this afternoon in another matter that's been put off until today. If we do get to Garrett and Moore this afternoon, Public Staff is prepared to move to our next panel and request that Garrett and Moore be moved to tomorrow morning. But if we don't even get there, we don't have to worry about it, but I just wanted to raise that.

CHAIR MITCHELL: All right. Thank you, Ms. Downey. Any additional matters for my consideration before we begin?

(No response.)

CHAIR MITCHELL: All right. Hearing none, we will return to NCSEA witness Barnes.

Whereupon,

JUSTIN R. BARNES,

having previously been duly affirmed, was examined and continued testifying as follows:

CHAIR MITCHELL: I believe we were with questions on Commissioners' questions. Any questions on Commissioners' questions?

MS. EDMONDSON: I had a couple of questions.

CHAIR MITCHELL: Is that Ms. Edmondson?

MS. EDMONDSON: Yes.

CHAIR MITCHELL: Ms. Edmondson, you may proceed.

EXAMINATION BY MS. EDMONDSON:

Q. Good morning, Mr. Barnes. Lucy Edmondson with the Public Staff.

Mr. Barnes, do you agree that there is value to capacity in all hours?

A. That's an interesting question. There is a certain amount of value to having, you know, base load capacity, not just capacity that's available, say, only during peak times. You know, traditionally, though, we assign a value of capacity, or we assign, you know, responsibility for costs based on contribution to, you know, some measure -- some measure of peak load, though.

Q. Do you agree that some value should be allocated to off-peak loads?

A. From -- you know, from simply kind of a cost allocation standpoint; is that your question?

Q. Yes.

A. I guess it depends on system -- on system conditions and exactly, kind of, how you -- you know, there are different ways in which you might attribute, you know, some level of cost responsibility to off-peak load. You know, which one you choose depends on the circumstances and the system conditions, though.

Q. Are you advocating that ED rates should not be allocated any existing rate base cost?

A. Well, my specific recommendations on -- you know, would -- my specific recommendations were based on existing rates. So modifications of existing rates, such as OPT-V. It's less clear exactly how you would do it from the standpoint of residential rates, but since though existing rates include embedded costs, you know, simply translating them or, you know, modifying them in the way that I suggested, you know, would kind of automatically account for the fact that you do have embedded costs. So it wouldn't be strictly kind of marginal cost-based pricing if you're utilizing existing rates.

Q. Another question. Aren't there some incremental investments beyond the meter that will be required to serve this additional load?

A. I think it depends -- you know, there certainly could be. It depends on, you know, the specifics of that additional load as to what those costs might be. You know, it's certainly plausible that if a, say, residential customer installs a certain size level 2 charger, they could, you know, exceed their existing service entrance capacity and potentially have to, you know, have that replaced or exceed the transformer capacity or, you know, cause some form of upgrade to be incurred.

It's certainly also possible that, if you're thinking about larger loads, you know, DCFC chargers, especially, say, concentrations of them, that you could certainly -- certainly have impacts on, say, like the primary distribution system from loads of that type that are not, maybe strictly speaking, kind of customer specific, if that makes sense.

Q. Yes.

A. So yeah, it's certainly plausible there could be, you know, say, additional distribution costs that would be presumably recovered through rates.

Q. How would you recover those?

A. Well, the specific recommendation I had for nonresidential customers was that the existing on-peak demand rates be translated to volumetric rates. And what that would accomplish is, you know; one, mitigating the effects of demand charges on, you know, relatively low utilization rate stations; two, you know, making the charges effectively kind of based on average contribution to during peak -- to load during peak periods.

Now, I did not suggest that the economy-demand charge, which is president OPT-V, and which I interpret is kind of like a -- you know, basically it's a noncoincident distribution to band charge. I did not recommend that that be translated into a volumetric rate. So just to kind of make that clear, you would have -- still have this kind of demand rate component for facilities in close proximity to the customer, whereas you're kind of more system-level demand costs would be assumed through a volumetric rather than an on-peak demand rate.

Q. Have you done any analysis of the cost in revenue curves associated with the incremental load of EVs?

A. No, I have not.

Q. And how do you propose the incremental cost in revenues associated with the load of EVs be recovered?

A. Well, I suppose you don't know, you know, right off kind of right at the start, if we assume -- you know, we don't know exactly how much EV load we are going to have. We don't exactly know how much the costs are going to differ, say, from embedded rates. I think you could, you know, possibly -- you could possibly track it and true it up as we do in, you know, many other ways in a rate case or -- you know, I'm not sure what the, kind of, regulatory, you know, ratemaking implications are of tracking it kind of like in a programmatic way and possibly establishing some form of other kind of, like, review interrupt. I suppose that's one possibility. But I would imagine that, you know, existing mechanisms, such as rate cases, kind of function as true-ups as well.

Q. And my last question. You -- you're familiar with Mr. Floyd's proposal for a rate study.

If we didn't create an EV rate here, but what would you think if we were able to do the rate study and prioritize development of EV rate in that rate study?

A. I would certainly be supportive of if we didn't, you know, adopt an EV rate here, that EV rates be prioritized. I can -- not knowing what the timeline is or what prioritization means, I guess I'm a little bit reluctant to venture an opinion on, you know, a very specific, kind of, I-approve-of-that approach. But yes, in principle, expediting is better than not expediting.

Q. All right. Thank you.

CHAIR MITCHELL: All right. Additional questions on Commissioners' questions?

MR. NEAL: Chair Mitchell, this is David Neal.

CHAIR MITCHELL: Mr. Neal, you may proceed.

EXAMINATION BY MR. NEAL:

Q. Good morning, Mr. Barnes.

A. Good morning.

Q. Just a quick follow up on part of your conversation with Commissioner Clodfelter around the same issue that you were just talking about, in terms of timing of adopting new rates.

Are you -- you are familiar with the pending Duke Energy Carolinas electric transportation pilot in Docket E-7, Sub 1195, correct?

A. I am somewhat familiar, insofar as I've reviewed it. I was most specifically kind of looking at, you know, rate proposals and whether they're not -- whether there were or were not rate proposals, but I'm fairly conversant, I would say.

Q. Would you agree that one way to address the timing concern that you've expressed would be for the Commission to order adoption of pilot EV-specific rates in the ET pilot, itself?

A. I'm not sure if I would refer to them as pilots. But that's, I guess, one procedural venue. Whether or not that's, kind of, procedurally appropriate, I don't know, but it's -- you know, it is one opportunity to take a bite of the apple, I suppose.

Q. Thank you.

MR. NEAL: No further questions, Chair Mitchell.

CHAIR MITCHELL: Okay. Additional questions on Commissioners' questions?

MS. JAGANNATHAN: Chair Mitchell, this is Molly Jagannathan for the Company. We don't have any questions.

CHAIR MITCHELL: Okay. Mr. Smith, any questions from NCSEA?

MR. SMITH: No questions from NCSEA.

CHAIR MITCHELL: Okay. All right. With that, Mr. Barnes, I believe you are off the hook for now, and you of may step down.

Do I need to entertain any motions, Mr. Smith?

MR. SMITH: Yes. Madam Chair, as this concludes Mr. Barnes' testimony in the Duke Energy Carolinas rate case, I'd move that his eight exhibits which were included with his prefiled direct testimony be admitted into the evidence for this case.

CHAIR MITCHELL: All right. Mr. Smith, hearing no objection to your motion, it is allowed.

(Exhibits JRB-1 through JRB-8, were

admitted into evidence.)

CHAIR MITCHELL: All right. Mr. Barnes, thank you for your testimony.

THE WITNESS: Thank you. Have a nice day.

CHAIR MITCHELL: All right. We are now with Sierra Club.

MS. CRALLE JONES: Good morning. Cathy Cralle Jones on behalf of the Sierra Club. Good morning, Chair Mitchell and Commissioners.

CHAIR MITCHELL: Good morning, Ms. Cralle Jones. You may call your witnesses.

MS. CRALLE JONES: Sierra Club calls Mr. Mark Quarles to the stand.

CHAIR MITCHELL: All right. Mr. Quarles, there you are. Would you raise your right hand, please, sir.

Whereupon,

MARK QUARLES,

having first been duly affirmed, was examined and testified as follows:

CHAIR MITCHELL: All right. You may proceed, Ms. Cralle Jones.

DIRECT EXAMINATION BY MS. CRALLE JONES:

Q. Mr. Quarles, could you please state your full name and business address?

A. My name is Mark Anthony Quarles. Business address is 1616 Westgate Circle, Brentwood, Tennessee.

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

A. I'm a branch manager and senior consultant for BBJ Group.

Q. On February 18, 2020, did you cause to be prefiled in this docket, direct testimony consisting of 34 --

A. I did.

(Reporter interruption due to sound failure.)

CHAIR MITCHELL: Ms. Cralle Jones, you trailed off at the end. I believe you said 34 pages; is that correct?

MS. CRALLE JONES: Consisting of 34 pages and 4 exhibits.

THE WITNESS: I did.

Q. Do you have any changes or corrections to your prefiled testimony?

A. I do not.

Q. And if I asked you the same questions again here today, would your answers be the same?

A. They would.

Q. Mr. Quarles, did you also prepare a summary of your direct testimony?

A. I did.

MS. CRALLE JONES: Chair Mitchell, that summary was served and filed per the Commission order. At this time, we ask that Mr. Quarles' prefiled direct testimony consisting of 34 pages, and summary of his testimony, be moved into the record as if given orally from the stand, and that prefiled Sierra Club Quarles Exhibit 1 through 4 be marked for identification as premarked.

CHAIR MITCHELL: All right. Mr. Quarles' prefiled testimony will be copied into the record as if delivered orally from the stand, as will his summary that has been provided to the parties as well as the Commission. The exhibits to his prefiled testimony will be marked as they were when prefiled.

(Sierra Club Quarles Exhibit 1 through 4 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct

testimony of Mark Quarles and summary of testimony were copied into the record as if given orally from the stand.)

I. PROFESSIONAL QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. Please state your name, occupation, and business address.

A. My name is Mark Quarles. I am a Senior Consultant and Nashville office Branch Manager of BBJ Group, an environmental engineering and consulting services firm with multiple offices in the United States. My business address is P.O. Box 58302, Nashville, Tennessee.

Q. Please summarize your educational and professional experience.

A. I graduated from Western Kentucky University in 1985 with a Bachelor of Science of Environmental Engineering Technology. My professional experience includes over thirty years as an environmental consultant. My experience includes clients and projects for industrial manufacturers, municipal governments, non-profit organizations, and legal services. I am a Licensed Professional Geologist in the State of Tennessee, a Registered Professional Geologist in the State of Georgia, and a Licensed Professional Geologist in the State of New York.

My specific experience for coal combustion waste related projects involves numerous years performing coal combustion related investigations at approximately 100 disposal sites located across the United States. Most of that experience has been in these Southeastern states: Alabama, Florida, Georgia, Kentucky, North Carolina, South Carolina, and Tennessee. I also was actively involved in efforts to respond to the Tennessee Valley Authority Kingston, Tennessee coal combustion residuals (“CCR” or “coal ash”) impoundment collapse in 2008, and I have been extensively involved in various CCR-related projects since that time.

I have conducted hydrogeologic investigations related to the closing of industrial waste ponds ("surface impoundments") and the siting and design of municipal and industrial waste landfills; developed closure plans for industrial landfills; designed and implemented groundwater monitoring programs for industrial and municipal landfills; and completed investigations to define the nature and extent of environmental contamination.

I have published peer-reviewed technical investigation papers involving soil, groundwater, and surface water associated with industrial waste contamination at national trade association conferences. I have also lectured at regional environmental law conferences.

My CV is attached at Exhibit MQ-1.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Sierra Club in this proceeding.

Q. Have you testified previously before the North Carolina Utilities Commission?

A. Yes, I previously testified at the Duke Energy Progress ("DEP") rate case hearing in 2017, Docket No. E-2 Sub 1142, and the Duke Energy Carolinas ("DEC" or the "Company") rate case hearing in 2018, Docket No. E-7, Sub 1146. My previous 2018 DEC testimony provided factual background about coal ash and evaluated the methods by which DEC proposed to close existing CCR surface impoundments in-place by leaving wastes in existing disposal areas (i.e., "closure-in-place") at its Allen and Marshall coal plants. That testimony evaluated whether or not the Company could meet the closure performance standards established by the U.S. Environmental Protection Agency ("US EPA") in its Final Rule for Hazardous and Solid Waste Management System; Disposal of Coal

Combustion Residuals From Electric Utilities (codified at 40 C.F.R. Part 257) ("CCR Rule"). I concluded in that testimony that, because of the site characteristics and hydrogeologic conditions at the Allen and Marshall sites, closure-in-place would not meet the closure performance standards established in the CCR Rule and that groundwater contamination would continue into the foreseeable future.

Q. What is the purpose of your direct testimony in this proceeding?

A. It is my understanding that the Company is seeking recovery from ratepayers for costs associated with the closure of surface impoundments and other disposal units in which CCRs (or "coal ash") have been stored at its facilities in North and South Carolina.

My testimony for this rate case hearing will focus on determining ***when*** the Company knew or should have known that groundwater and/or surface water contamination was likely due to storage and disposal of CCRs in unlined areas located near—and even sometimes within—rivers and streams and where the ash is saturated with groundwater.

Q. What information did you consider when preparing your testimony?

A. I have researched electric power industry practices and standards dating to the 1970s and have reviewed historical governmental documents and regulations, recent investigative reports and analyses completed by the Company or by consultants on its behalf, the Company's Application and certain testimony, as well as documents produced by the Company during discovery in this proceeding and introduced as exhibits in the previous rate case proceedings. Specific documents that I rely upon include:

- Argonne National Laboratory, Environmental Control Implications of Generating Electric Power from Coal, 1976 (Public Staff Junis Direct Exhibit 4, Docket No. E-7, Sub 1146) (hereafter "1976 Argonne Report");

- Los Alamos Scientific Laboratory, The Disposal and Reclamation of Southwestern Coal and Uranium Wastes, May 1979 (Public Staff Junis Exhibit 6, Docket No. E-7, Sub 1146) (hereafter "1979 Los Alamos Report");
- Arthur D. Little, Inc./US EPA, Health and Environmental Impacts of Increased Generation of Coal Ash and FGD Sludges, Report to the Committee on Health and Ecological Effects of Increased Coal Utilization, Environmental Health Perspectives, 1979 (Public Staff Junis Direct Exhibit 7, Docket No. E-7, Sub 1146) (hereafter "1979 EHP Report");
- US EPA/Tennessee Valley Authority, Behavior of Coal Ash Particles in Water, Trace Metal Leaching and Ash Settling, Mar. 1980 (hereafter "1980 EPA Ash Report");
- Electric Power Research Institute, Coal Ash Disposal Manual, Second Edition, Oct. 1981 (Sierra Club Kerin Cross Exhibit 4, Docket No. E-7, Sub 1146) (hereafter "1981 EPRI Manual");
- Electric Power Research Institute, Manual for Upgrading Existing Disposal Facilities, Nov. 1981/Aug. 1982 (Public Staff Junis Direct Exhibit 8, Docket No. E-7, Sub 1146) (hereafter "1982 EPRI Manual");
- Duke Power Co., Investigations of Coal Ash Disposal and Its Impact upon Groundwater, Dec. 1984 (DEC Response to Sierra Club Data Request No. 5-3, January 28, 2020) (hereafter "Duke 1984 Groundwater Report"), attached as Exhibit MQ-2;
- Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, June 1985 (DEC Response to Sierra Club Data Request No. 5-3, January 28, 2020) (hereafter "1985 AD Little Report"), excerpts attached as Exhibit MQ-3;
- Duke Power Co., Evaluation of the Effect of Ash Disposal at the Riverbend Plant of Duke Power Company on Groundwater and Surface-Water Quality, 1987 (Public Staff Wells Cross Exhibit 8, Docket No. E-7, Sub 1146) (hereafter "1987 Riverbend Report");
- US EPA, Report to Congress, Wastes from the Combustion of Coal by Electric Utility Power Plants, Feb. 1988 (Public Staff Junis Direct Exhibit 10, Docket No. E-7, Sub 1146) (hereafter "1988 EPA Report to Congress");
- US EPA & US DOE, Coal Combustion Waste Management and Landfills and Surface Impoundments, 1994-2004, Aug. 2006 (hereafter "2006 EPA/DOE CCR Report");
- US EPA, Monitored Natural Attenuation of Inorganic Contaminants in Groundwater, Volume 2, Oct. 2007 (hereafter "2007 EPA Attenuation");
- Duke Energy Senior Management Committee, Ash Basin Closure Update, January 13, 2014 (Attorney General's Office Fountain Cross 6, Docket No. E-7, Sub 1146) (hereafter "2014 Duke Ash Update");

- Duke Energy, Comprehensive Site Assessment Report, Allen Steam Station, Aug. 2015 (hereafter "2015 Allen Site Assessment");
- Comprehensive Site Assessment Update, Allen Steam Station, Jan. 2018 (hereafter "2018 Allen Site Assessment");
- DEC Response to Attorney General's Office Data Request No. 2-18 (Attorney General's Office Kerin Direct Cross Exhibit 8, Docket No. E-7, Sub 1146) (hereafter "Ash Ponds DR");
- DEC Response to NC Public Staff Data Request 36-2, January 15, 2018 (hereafter "Voluntary Wells DR"), attached as Exhibit MQ-4.

Where appropriate, I will refer to specific pages of these documents in support of my conclusions.

Q. Please summarize your conclusions and recommendations for the Commission for this rate case hearing.

A. I recommend that the Commission make the following findings and give such findings due consideration as it evaluates the Company's request:

1. Historical documents, including the Electric Power Research Institute manuals, available to the Company, demonstrate that the environmental risks associated with the disposal of coal ash in unlined surface impoundments were understood by the electric utility industry in the late 1970s and early 1980s.
2. The Company's continued operation of unlined surface impoundments that were constructed directly in streams, adjacent to rivers and streams, with coal ash saturated in groundwater, without adequate groundwater monitoring for decades after the industry recognized the risks of such operation, was unreasonable and could be expected to result in the introduction of CCR constituents to surface and groundwater.
3. The Company's 1984 investigation at its Allen site that identified a leachate plume in groundwater was a warning sign and early indication that unlined

surface impoundments leaked and presented risks to groundwater quality. The Company's failure to take action following that investigation was unreasonable.

4. Standing water in the impoundments, leakage of that water into the shallow aquifer below, submerged CCRs in the impoundments, and the mounding effects and radial flow conditions of the aquifer, have resulted in more widespread contamination and increased groundwater flow velocities of the contaminated aquifer towards receptors and receiving streams.

5. Costs associated with excavation and groundwater monitoring likely would be lower if the Company had converted to dry disposal in lined landfills sooner.

II. PREVIOUS RATE CASE TESTIMONY AND SUBSEQUENT ACTIONS REGARDING COAL ASH POND CLOSURE

Q. Please summarize the conclusions you made as part of the 2018 DEC rate case.

A. My 2018 DEC testimony, based upon my review of internal Company documents, external research, and my experience conducting CCR-related investigations in multiple states, concluded that:

- The Company constructed CCR surface impoundments over existing streams and those former stream valleys became the disposal units over time. (As this current testimony will discuss, the CCRs were allowed to stack higher each year and to spread laterally throughout stream valleys, creating larger "footprints" of wastes.)

- The Company continued to build new unlined disposal areas and expand existing ones through the 1990s, to operate unlined surface impoundments through the present day, and to stack wastes on top of unlined disposal areas—even though utilities around the United States have been constructing lined disposal areas since the mid-

1970s and despite an understanding of contamination risks associated with disposal in unlined ponds.

- Since at least the mid-1970s, it was reasonable for the Company to expect CCR contamination of groundwater and surface waters because of its use of unlined surface impoundments.

- CCRs in the Company's unlined surface impoundments have been submerged and saturated in groundwater. On-going leaching of coal ash constituents has resulted in groundwater contamination beneath and downgradient of the disposal areas. That contamination has exceeded North Carolina Department of Environmental Quality ("NCDEQ") and US EPA standards.

- The Company's plan to close surface impoundments via closure-in-place did not include any mechanism to stop groundwater from flowing laterally into wastes and, therefore, would not have prevented continued leaching of metals and other constituents into groundwater or the introduction of those constituents into adjacent rivers and streams. Thus, the Company's closure plans could not satisfy CCR Rule performance standards.

- Excavation and removal of CCRs to lined, dry disposal areas would reduce the concentrations of groundwater constituents and would reduce the extent of groundwater contamination over time.

Q. Has the Company been required to excavate CCRs from its surface impoundments rather than closing those units in place?

A. Yes. In April 2019, the North Carolina Department of Environmental Quality ("DEQ") ordered the Company to excavate coal ash at its Allen, Belews Creek, Cliffside, and

Marshall sites. (DEQ also ordered the Company's sister utility DEP to excavate coal ash at the Mayo and Roxboro sites.) The Company challenged DEQ's decision, but the Company ultimately agreed to excavate and remove all coal ash except for some limited exceptions from the unlined ponds at the Allen, Belews Creek, Cliffside, and Marshall plants and conduct groundwater monitoring and groundwater remediation.

III. BACKGROUND ON COAL COMBUSTION RESIDUALS (CCRS)

Q. What are coal combustion residuals ("CCRs") and how are they generated?

A. CCRs are solid wastes that are created by the preparation and burning of coal to produce electricity. The primary solid wastes that are generated during that process include bottom ash, fly ash, pyrite/mill rejects, and synthetic gypsum. Bottom ash is heavier and consists of larger particles of ash that are generated during combustion and fall to the bottom of the furnace. Fly ash is the smaller, fine-particle ash that forms during combustion and is carried out of the boiler by the flue gases and is then collected by the air pollution control dust collection system. Synthetic gypsum is created when flue gas desulfurization ("FGD") air pollution control technology is used to scrub air emissions.

At the Company's facilities, CCRs have been mixed with large amounts of water and sluiced to surface impoundments ("ponds") located at the power plant sites. The heavier substances would sink to the bottom of the ponds, and the transport water would be discharged into a nearby waterway, evaporate, or seep into the ground (and groundwater) beneath the pond.

Q. What constituents are commonly found in CCRs?

A. Constituents that are found in the CCRs generally originate from the source coal that is burned. Aluminum, arsenic, boron, calcium, hexavalent chromium, iron, magnesium, manganese, silicon, strontium, sulfate, and sulfur are commonly present.

Q. Are CCRs constituents water-soluble?

A. CCR constituents are water-soluble, and that solubility depends on numerous factors such as the pH of the solid-to-water mixture and the geochemical conditions under which the CCRs exist. Those conditions can change over time after closure and therefore, constituents that had not previously migrated from a disposal unit can become mobile in the future.

Q. Are there risks to the environment posed by exposure to CCR constituents?

A. Yes. CCR constituents can leach from the solid waste when it comes into contact with water—including transport water, groundwater, rainwater, or stormwater run-off. The risks to the water environment originate when those constituents are leached from the solid CCR and then transported away from the disposal area in groundwater and surface water. Constituent risks vary by each constituent—with risks to humans, fish and aquatic life being common.

Q. How typical are surface water and groundwater impacts when CCRs are stored in unlined surface impoundments adjacent to surface waterbody and/or beneath the groundwater table?

A. In my experience of investigating coal ash disposal sites across the country as well as reviewing historic reports, contamination of surface water and groundwater by CCR constituents that are introduced into the environment via unlined ponds is quite common.

IV. KNOWLEDGE OF RISKS ASSOCIATED WITH DISPOSAL OF COAL ASH IN UNLINED SURFACE IMPOUNDMENTS

Q. How early were the risks associated with disposing of coal ash in unlined surface impoundments recognized by the scientific community?

A. The risks of groundwater contamination from unlined coal ash ponds were understood as early as the late 1970s. For example, a report prepared by the Argonne National Laboratory in 1976 identified the "potential problems of pollution of surface and subsurface water" associated with ash disposal and noted that "[u]tilities are well aware of these problems." (1976 Argonne Report at 169 [PDF page 57].) A 1979 report by Arthur D. Little consultants and US EPA identified groundwater and surface water contamination as major "impact issues" associated with the storage or disposal of coal ash in unlined units. (1979 EHP Report at [PDF pages] 2, 10, 19, 23.)

In addition, a 1979 report regarding the disposal of coal and uranium waste noted a "growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination." (1979 Los Alamos Report at 6 [PDF page 7].) The report went on to explain: "Many trace contaminants that are present in the fly ash or sludge can be mobilized by the waters present in the ponds. The transport of contaminants from the disposal ponds into shallow or deep aquifers could result in the degradation of the quality of these waters." (1979 Los Alamos Report at 7 [PDF page 8].)

Q. Did the US EPA recognize the risks to groundwater associated with coal ash disposal?

A. Yes. Recognition of such risks is reflected in the fact that fly ash, bottom ash, and other coal combustion residuals have been regulated as solid wastes under the Resource

Conservation and Recovery Act ("RCRA") since 1979. Those regulations prohibit solid waste disposal facilities, including coal ash disposal sites, from contaminating underground drinking water sources beyond the solid waste boundary or state-approved alternative boundary. (40 C.F.R. § 257.3-4(a).) When promulgating those regulations, US EPA highlighted the importance of groundwater monitoring in order to ensure that solid waste disposal sites were not causing such contamination: "Existing monitoring of ground-water contamination is largely inadequate; many known instances of contamination have been discovered only after groundwater users have been affected. The Act and its legislative history clearly reflect Congressional intent that protection of ground water is to be a prime concern of the criteria." (44 Fed. Reg. 53,438, 53,445 (Sept. 13, 1979).)

In addition, US EPA reports published in 1980 and 1988 documented the agency's concerns about leaking, unlined disposal units. The conclusions of those reports were based on self-reported data regarding industry waste disposal practices from at least the mid-1970s. EPA's key conclusions include:

- "[A]sh deposited in the bottom of the ash pond may continue to leach where the ash is in contact with groundwater if the surrounding environment is changed to anaerobic and low-pH conditions." (1980 EPA Ash Report at 7 [PDF page 20].)
- "The most significant problems associated with ash disposal in ponds are . . . quantities of trace metals in groundwater leachate." (1980 EPA Ash Report at 3 [PDF page 16].)
- "The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause groundwater contamination." (1988 EPA Report to Congress at E-3 [PDF page 17].)

Q. What about the utility industry? When did it recognize the risks associated with disposing of coal ash in unlined surface impoundments?

A. In 1981, the Electric Power Research Institute ("EPRI")—a well-known industry research collaborative—published a manual regarding the handling and disposal of coal ash that noted: "leachate from ash disposal sites is of concern due to the possibility that the heavy metals . . . present in the ash may enter the groundwater system and contaminate present or future drinking water sources." (1981 EPRI Manual at 2-17.)

In addition, that report discussed EPA's solid waste disposal guidelines and noted that "[g]roundwater resources in the vicinity of the site should be surveyed to establish background data on water quality; depth, direction, and rate of flow of groundwater; and potential interaction between the landfill and ground and surface waters; and hydraulic conductivity and attenuating capacity of the site soils" (1981 EPRI Manual at 4-12), that "the bottom of the landfill should be maintained at least 5 feet [] above the seasonal high water table" (1981 EPRI Manual at 4-12), and that "[a] groundwater monitoring system should be installed if the landfill has potential for discharge to underground drinking water sources" (1981 EPRI Manual at 4-14).

While the RCRA regulations discussed in the EPRI report applied to solid waste landfills, the risks created by the storage or disposal of coal ash in unlined units—whether dry landfills or wet impoundments—are comparable. Addressing the risk of groundwater contamination by unlined ash ponds directly, the 1982 EPRI manual stated that "inadequately lined ponds provide a greater opportunity for groundwater contamination, because the soil immediately below the pond is always saturated and under a constant head of pressure from the overlying water. Consequently, seepage may be constant and greater in volume than leachate from a landfill." (1982 EPRI Manual at 2-11.) The manual laid out what any professional engineer, and certainly anyone involved with the construction or operation of an acres-large ash surface impoundment, should understand—that sluicing and impounding waste together with large amounts of water creates a "constant driving force for movement of potentially contaminated water (leachate) through the settled waste and into the surrounding soil." (1982 EPRI Manual at 2-2.)

Q. Did the utility industry recognize the need to monitor groundwater at coal ash disposal sites?

A. Yes. In 1982, EPRI made clear that regulatory compliance by itself might not ensure environmental protection and advised that utilities must achieve both, noting that "[p]otential deficiencies in utility waste disposal practices may be defined by two sets of standards: [1] The disposal practice does not comply with specific federal and/or state regulatory requirements; [2] The site has the potential to contaminate the environment." (1982 EPRI Manual at 4-1.) Accordingly, EPRI reached this conclusion: "[a]n engineering assessment of site adequacy must therefore address (1) whether the operation complies with prevailing regulations, and (2) whether the site poses a threat to the local environment. Both problems must be addressed simultaneously." (1982 EPRI Manual at 4-2.)

The 1982 EPRI manual reported on a survey it had conducted of existing coal ash disposal sites and highlighted the "potential deficiencies . . . noted during several of the site visits" including that "[g]roundwater monitoring was inadequate or nonexistent" and "leachate monitoring was not practiced." (1982 EPRI Manual at 4-19.) The manual further emphasized the risks of groundwater contamination and advised utilities to conduct groundwater monitoring:

> "[A]lthough the requirement for groundwater and leachate monitoring is not specified in federal standards for solid waste disposal facilities, the regulations do emphasize groundwater protection. While groundwater can be protected and leachate generation can be minimized with sound engineering design and site operation, ***monitoring of groundwater and leachate, is nevertheless necessary to provide convincing proof of safe disposal practice***. . . .
>
> "Finally, the potential for groundwater degradation should be noted, ***especially when an unlined ash pond is constructed on a site with relatively permeable soils and a shallow groundwater table***. . . . The existence of a constant hydraulic head (standing water) in the pond ***makes leachate generation and migration inevitable***." (1982 EPRI Manual at 4-19, emphasis added.)

Indeed, the 1982 EPRI Manual identified North Carolina state regulatory requirements designed to protect groundwater at coal ash disposal sites: prohibiting siting of disposal units where the water table is near the surface or within a 100-year floodplain (1982 EPRI Manual at 3-18) and requiring groundwater monitoring at sites with marginal soil permeability characteristics (1982 EPRI Manual at 3-19). Describing federal groundwater monitoring requirements, the 1981 EPRI Manual noted that "the location and depth of a groundwater monitoring well(s) is the single most important aspect of a groundwater monitoring program." (1981 EPRI Manual at 7-10.)

Q. Were disposal options that could lessen the risks associated with disposing of coal ash in unlined surface impoundments available in the 1980s?

A. Yes. For example, the 1981 EPRI Manual noted the trend toward dry ash handling systems (1981 EPRI Manual 3-1), and the 1982 EPRI manual identified as a "promising upgrading technique" "the conversion of a wet disposal system (pond) to a dry system (landfill)." (1982 EPRI Manual at S-2.) EPRI also recognized that "ponding is not considered a method for permanent disposal" and that the "increased land requirement and eventual problem of site closure favor dry disposal." (1982 EPRI Manual at 2-2.)

In addition, the 1988 EPA Report noted a trend toward the construction of disposal units with some sort of clay or composite liner to protect groundwater. Notably, EPA found that:

- "40 percent of the generating units built since 1975 have liners." (1988 EPA Report to Congress at ES-3 [PDF page 17].)
- "Lining is becoming a more common practice, however, as concern over potential ground-water contamination from 'leaky ponds' and, and to a lesser extent, from landfills has increased." (1988 EPA Report to Congress at 4-24 to 4-25 [PDF pages 164-165].)
- "Mitigation measures to control potential leaching include installation of liners, leachate collection systems, and ground-water monitoring systems and corrective action to clean up groundwater contamination." (1988 EPA Report to Congress at ES-5 [PDF page 19].)
- Regarding the trend towards disposal of coal ash in landfills rather than surface impoundments: "These trends in utility waste management methods have been changing in recent years, with a shift towards greater use of disposal in landfills located on-site. For example, for generating units built since 1975, nearly 65 percent currently dispose of coal combustion wastes in landfills, compared to just over 50 percent for units constructed before 1975." (1988 EPA Report to Congress at 4-25 [PDF page 165].)
- ". . . landfilling has become the more common practice because less land is required, and it is usually more environmentally sound (because of the lower water requirements, reducing leaching problems, etc.)." (1988 EPA Report to Congress at 6-5 [PDF page 323].)

By the 1990s, liners were the rule: from 1994 to 2004, "virtually all newly built or expanded units (97 percent of landfill and 100 percent of surface impoundments)" were constructed with liners. (2006 EPA/DOE CCR Report at 37 [PDF page 67].)

V. DUKE ENERGY'S MANAGEMENT OF COAL COMBUSTION RESIDUALS IN THE CAROLINAS

Q. How has Duke Energy managed CCRs at its North and South Carolina sites?

A. Historically, CCRs generated by the Company's coal-burning units have been stored in unlined pits located at the power plant sites. For its eight power plants in the Carolinas—

Allen, Belews Creek, Buck, Cliffside, Dan River, Marshall, Riverbend, and W.S. Lee (South Carolina)—the Company constructed surface impoundments in the 1950s, 1960s, and 1970s and expanded many of those impoundments between the 1960s and 1980s (as shown in figure below). Not a single impoundment was constructed with a liner and, at each one, wastes were placed in direct contact with groundwater. (See Ash Ponds DR.) The Company also continued to construct new storage and disposal areas over those unlined impoundments.

Plant Name	Unlined Disposal Area	Built	Expanded
Allen	Retired Ash Basin Active Ash Basin	1956-1957 1972	1965, 1968 None
Belews Creek	Ash Basin	1972-1974	None
Buck	Ash Basin 3 (Primary Basin) Ash Basin 2 (Secondary Basin) Ash Basin 1 (Primary Basin)	1956-1957 1956-1957 1982	None 1977 None
Cliffside	Unit 1-4 Ash Basin Unit 5 Ash Basin Active Ash Basin	1956-1957 1971-1972 1974	None None 1974
Dan River	Ash Basin	1956	1968
Marshall	Ash Basin	1962-1964	None
Riverbend	Ash Basin	1956-1957	1979
WS Lee	Original Ash Basin New Ash Basin	1951 1973-1974	1956, 1959 1975, 1985

Q. When did the Company first monitor groundwater at its coal ash disposal sites?

A. According to its responses to data requests in this proceeding, the Company began "voluntary" monitoring of groundwater at the Dan River site in 1993, at Cliffside in 1995, and at its other sites between 2004 and 2006. (See Exhibit MQ-4, Voluntary Wells DR.)

Plant	Voluntary Monitoring Well Installation	"Required" Monitoring Well Installation	Detection of 2L Standard Exceedances	Years Between Construction and First Monitoring
Allen	2004, 2005	2011	2004	48
Belews Creek	2006	2012	2007	34
Buck	2006	2011	2006	50
Cliffside	1995, 2005, 2007, 2010	2011	2008	39
Dan River	1993, 1995, 2007	1993	1993	37
Marshall	2006, 2016	2011	2007	44
Riverbend	2006, 2016	2011	2008	50
WS Lee	Not Provided	Not Provided	Not Provided	Not Provided

Q. What were the results of the Company's initial "voluntary" groundwater monitoring?

A. Voluntary monitoring results indicated exceedances of state groundwater standards (as set forth in the North Carolina Administrative Code, Title 15A, Subchapter 2L and commonly referred to as "2L Standards") at coal ash sites within the first year or two after monitoring commenced (except Cliffside).

Q. Upon learning of such exceedances, did the Company take any action to limit the introduction of coal ash constituents into groundwater or abate the contamination?

A. No. Instead, the Company took the position that the groundwater monitoring results "appeared consistent with natural-occurring conditions." (See Exhibit MQ-4, Voluntary Wells DR.)

Q. Was the Company's conclusion that CCR constituents detected during groundwater monitoring were naturally occurring a reasonable one?

A. No. That conclusion has been shown to be incorrect. In fact, the Company itself concluded in 2014 that "our coal ash is impacting groundwater at all locations," when referring to its Coal Ash Program. (See 2014 Duke Ash Update at 3.)

Q. Were any groundwater investigations undertaken at the Company's coal ash sites in the 1980s prior to "voluntary" monitoring programs?

A. Yes. In the early 1980s, a contractor retained by the US EPA (Arthur D. Little, Inc.) conducted a "generic assessment" to characterize utility wastes and to evaluate the engineering aspects and costs associated with disposal. (Exhibit MQ-3, 1985 AD Little Report.) The assessment identified six power plant sites—including the Allen site—as representative of nationwide conditions and conducted sampling of groundwater, waste, and surface water at each site.

Q. What did the 1985 Arthur D. Little Report conclude about groundwater contamination at the Allen site and its effect on water quality?

A. At the Allen site, twenty monitoring wells were sampled as part of the Arthur D. Little analysis. (Exhibit MQ-3, 1985 AD Little Report at 5-4 [PDF page 14].) Arsenic concentrations in groundwater beneath the Allen site exceeded drinking water standards. (Exhibit MQ-3, 1985 AD Little Report at 5-14, 5-5-22 [PDF pages 24, 32].) Nevertheless, the report concluded that impacts were expected to be "insignificant," apparently looking only at impacts to the adjacent surface waterbody but not to groundwater quality. The "insignificant" conclusion relied upon the dilution of groundwater discharges into the receiving stream due to the stream flow volume being more than the volume of groundwater discharges into the stream.

Q. Was the Company's reliance on the 1985 Arthur D. Little Report for its decision not to conduct groundwater monitoring at the Allen and other coal ash disposal sites reasonable?

A. No. The report acknowledged that steady-state groundwater conditions at the Allen site had not yet been reached in downgradient groundwater monitoring wells—meaning that the full contaminant plume had not yet reached downgradient wells and contaminant concentrations could get much worse. (Exhibit MQ-3, 1985 AD Little Report at 5-23 to 5-24 [PDF page 33-34].) Also, soil attenuation estimates made using laboratory leaching tests using on site soil and wastes did not accurately predict actual groundwater well concentrations. (Exhibit MQ-3, 1985 AD Little Report at 5-22 [PDF page 32].)

Lastly, the report concluded that increasing constituent concentrations in downgradient wells "would be expected;" available data "cannot support a precise estimate of future groundwater quality;" and steady-state concentrations "may range between existing concentrations and concentrations typical of ash leachate." (Exhibit MQ-3, 1985 AD Little Report at 5-24 [PDF page 34].) And despite its deficiencies, the report did highlight the potential threat to groundwater resources, documenting existing contamination and the risk of downgradient concentrations of CCR constituents increasing over time. Indeed, as discussed before, EPRI recognized that site-specific geologic and hydrogeologic characterizations were necessary to evaluate risks of surface and groundwater contamination.

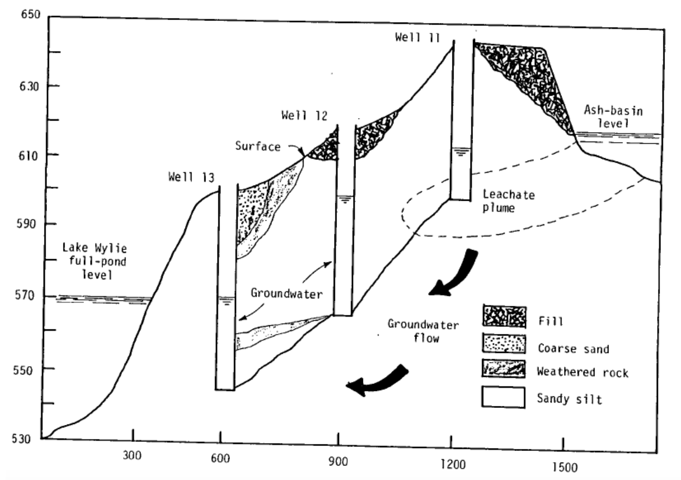
Q. Did other Company groundwater studies in the 1980s determine that contaminants can leach from CCRs and degrade groundwater quality?

A. Yes. In 1984, the Company reported the results of an internal investigation that was completed in response to the "question of any leaching of ash constituents to groundwaters raised in 1978 in light of the increased scrutiny by regulatory agencies." That study included leaching tests for wastes from all Company power plants and groundwater monitoring at the Allen site. (Exhibit MQ-2, Duke 1984 Groundwater Report at 1-2 [PDF pages 4-5].)

The 1984 investigation evaluated the performance of the Allen impoundments and sought to determine their effect on groundwater movement and water quality. (Exhibit MQ-2, Duke 1984 Groundwater Report at 14 [PDF page 17].) More specifically, the investigation sought to determine the soil attenuation capacity—that is, determining how long soils beneath the Allen coal ash pond could retain CCR constituents that had been introduced via leaching from the pond to prevent downgradient migration of contaminants in groundwater. Duke collected groundwater samples from thirteen wells (reportedly installed in 1978) and conducted leaching tests for CCRs. (Exhibit MQ-2, Duke 1984 Groundwater Report at 2, 9, 10, 19 [PDF pages 5, 12, 13, and 22].)

The results of the laboratory leaching tests at Plant Allen indicated that leachate produced from fly ash exceeded the allowable Maximum Contaminant Level ("MCL") for arsenic at that time (50 ug/L). (Exhibit MQ-2, Duke 1984 Groundwater Report at 9-10 [PDF pages 12-13].) Groundwater results from one well (MW-4, 112.5 ug/L) located beneath the Inactive Ash Pond exceeded the MCL for arsenic. (Exhibit MQ-2, Duke 1984 Groundwater Report at 29 [PDF page 32].)

The Company also determined that a "leachate plume" existed in the groundwater, as illustrated below. (Exhibit MQ-2, Duke 1984 Groundwater Report at 28 [PDF page 31].)



Q. Did the 1984 investigation at Allen support the Company's belief that groundwater monitoring wells were not necessary due to soil attenuation capacity?

A. No. The Company did not reach any conclusion about the ability of soil to attenuate or prevent the migration of constituents away from the impoundments. (Exhibit MQ-2, Duke 1984 Groundwater Report at 26-27 [PDF pages 29-30].) As a result, the Company had no data to support its belief that soil attenuation capacity would mitigate contamination in the short or long-term. In fact, the investigation demonstrated leakage from the impoundment to groundwater—but the results could have been much worse if monitoring wells had been properly constructed. Six of the thirteen wells likely under-reported constituent concentrations because those wells were constructed with screened intervals deeper than the uppermost portion of the aquifer (missing the "perched" water table), and two of those wells (of the three along Lake Wylie) likely under-reported constituent concentrations that discharged into the river. (Exhibit MQ-2, Duke 1984 Groundwater Report at 19, 23 [PDF pages 22, 26].)

Q. What is soil attenuation capacity?

A. Soil attenuation capacity is a process in which contaminants can be “attenuated” by chemical processes in aquifer solids (i.e., soil) and the groundwater. Using arsenic as one example because it is prevalent in CCRs, the US EPA concluded that long-term attenuation is dependent upon numerous factors such as pH, changes in the redox potential, the presence of iron oxides and sulfides, and microbial interactions—geochemical conditions are site-specific. (2007 EPA Attenuation at 43-47.) According to the US EPA, those conditions can change at a disposal site over time and, if such conditions occur, previously immobilized contaminants like arsenic can be remobilized to a new contaminant plume. (2007 EPA Attenuation at 49.)

EPRI also recognized in 1982 that site-specific geochemical conditions dictate the attenuation capacity of contaminants by subsurface materials. According to EPRI, the degree of retardation—or the attenuation capacity of the soil—is based upon site-specific factors such as the clay and organic content of the soil, leachate pH over time, the buffering capacity of the soil, the amount of iron and aluminum oxides in the soil, and the oxidation states of metals, as examples. (1982 EPRI Manual at 2-12.) EPRI further concluded that the nature and extent of the leaching threat to groundwater “will have to be evaluated for each waste and disposal site.” The key takeaway is that each waste and each site is unique and requires its own analysis to determine the ability of soil to prevent contaminants from migrating over time. (1982 EPRI Manual at 2-13.)

Q. Can soil attenuation protect against migration of CCR constituents over the long term?

A. As previously discussed, the ability of soil to attenuate contaminants is based upon numerous waste and site-specific geologic, hydrogeologic, and geochemical factors. Sluiced water, leachate, and groundwater conditions such as pH can change over time and as a result, the attenuation capacity of the soil can also change. Also, the ability of soil to immobilize contaminants is affected by the "mass" or contaminant loading of contaminants added to the aquifer over time as the leaching continues. (2007 EPA Attenuation at 50.) The longer the impoundments are operated, the more contaminant mass is added to the surface.

The dike fill materials, the underlying alluvium, and the residuum soils at the Allen site are very gravelly and sandy (2015 Allen Site Assessment at 73, 123), with limited amounts of clay. Gravel and sand are much less effective in attenuating contaminants compared to clay, for example, because they are preferential pathways for faster groundwater flow. The Company built impoundments throughout its system within streams channels, stream valleys, and within floodplains. The soils at each of those sites would contain significant amounts of sand and gravel. As such, the attenuation capacity of the soil within the aquifers at DEC's ash disposal cannot be relied upon as a long-term mitigator of contaminants that leak from unlined impoundments.

Q. Was the Company's conclusion in 1984 that soil attenuation capacity would prevent contaminant migration reasonable?

A. No, for numerous technical reasons as discussed above. Each power plant site would have unique conditions that would affect the soil attenuation capacity over time. For example, soil conditions of clay, sand, and gravel and the associated preferential flow pathways would be site-specific. Also, the contaminant mass loading would increase over the life of the impoundments as new sluice waters were discharged into the impoundments. The contaminant plume would also enlarge because the impoundment footprint would also enlarge. Lastly, the geochemical conditions of the subsurface would also change over time. The 1984 investigation apparently did not consider those changing site conditions. Although one purpose of the 1984 investigation was to predict the attenuation capacity over time, the Company did not conclude that attenuation would prevent groundwater contaminants from migrating away from the disposal areas over time.

Q. Did the Company rely on assumptions about soil attenuation capacity at sites other than Allen?

A. Yes. The Company decided not to conduct groundwater monitoring at the Riverbend site based on its incorrect assumption that soil attenuation would protect against CCR constituent migration. In connection with a permit application for a new ash basin in 1987, North Carolina state regulators required the Company to assess groundwater quality; to determine the effects of groundwater discharge on the Catawba River; and to propose a monitoring well network "sufficient to detect any contaminants which could reach the river." (1987 Riverbend Report at 2.) However, following the investigation, the Company concluded that a groundwater monitoring program was not needed at the Riverbend Plant because any pollutants released from the ash ponds would be immobilized in the soils beneath the ponds. (1987 Riverbend Report at 2, 3.) In support of this conclusion, the Company pointed to similarities between soil and hydrogeologic conditions at the Allen and Riverbend sites, located twelve miles apart.

Q. Do you agree with the conclusions made in the 1987 Riverbend report?

A. No. The Company assumed incorrectly (and without collecting site-specific data on soil type, waste type, and aquifer conditions) that enough similarities existed between the Allen and Riverbend sites to warrant not installing monitoring wells at Riverbend. The Company also incorrectly assumed that aquifer and soil geochemical conditions would not change over time, ignoring the fact that the contaminant mass loading to the subsurface would increase over time as the impoundments aged and the geochemical conditions would also change.

Q. Was it reasonable for the Company to operate its unlined coal ash surface impoundments for decades without monitoring groundwater quality?

A. No. As discussed earlier, the industry was well aware of the risks of contamination associated with the storage or disposal of CCRs in unlined ponds near waterbodies and groundwater. The only prudent option for learning whether a given impoundment was causing contamination of water resources was to install and sample monitoring wells.

Q. Was it reasonable for the Company to continue operating existing unlined CCR disposal units and to expand or build new unlined units during and after the 1980s?

A. No. The utility industry and US EPA recognized since at least the mid-1970s that unlined surface impoundments and landfills represented a threat to groundwater quality. Disposal of municipal and industrial solid wastes in engineered disposal units (e.g., designed with a liner, leachate collection system, etc.) has been commonplace since the mid-1970s. The understanding of these risks only grew in the years that followed. As such, construction or expansion of unlined disposal units after the mid-1970s was unreasonable.

The continued operation of unlined coal ash disposal units after the 1980s also was unreasonable. Despite the industry-wide understanding of the risks of disposing of coal ash in unlined areas near water resources, the Company did not operate adequate groundwater monitoring systems around its coal ash disposal areas—most if not all of which were located in stream beds or directly in contact with groundwater—until the 2000s, decades after it began CCR disposal. This was unreasonable. The ample information available to the Company regarding the risks associated with unlined disposal unit operations should have led the Company to begin to transition away from wet handling and disposal of coal ash much sooner. And at the very least, the Company should have begun monitoring the groundwater at its sites much sooner.

Q. Has the Company's storage and disposal of coal ash in unlined surface impoundments caused impacts to groundwater?

A. Yes. The Company itself concluded in 2014 that "our coal ash is impacting groundwater at all locations," when referring to its Coal Ash Program. (See 2014 Duke Ash Update at 3.) Contamination has reportedly migrated off-site at several of the Company's sites (in the Carolinas and in other states) and towards groundwater supplies.

In numerous cases, rather than initiating corrective actions to eliminate or mitigate the contamination, Duke Energy companies have responded by purchasing affected properties or providing alternative drinking water sources. (2014 Duke Ash Update at 46, 65.) For example, at the Sutton site, DEP removed two public drinking water wells from service and provided an alternative supply. At the H.F. Lee site, DEP purchased the land within 500 feet of the site. At the Mayo site, DEP purchased property immediately downgradient of its ash basin. Both DEC and DEP have provided bottled water to residents near ash sites. In Indiana, Duke Energy bought and demolished one home and connected others to the municipal water supply.

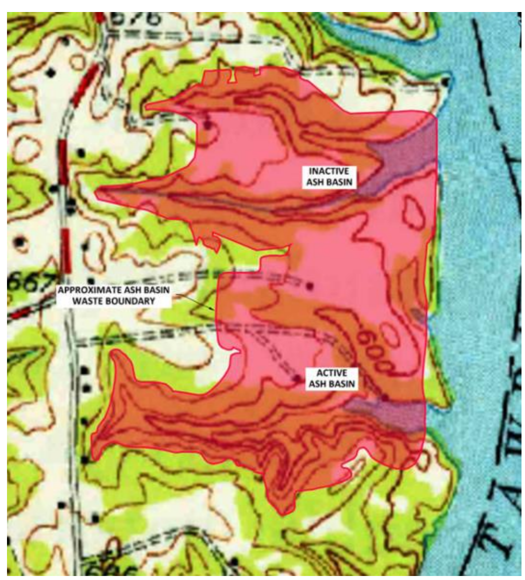
V. <u>GROUNDWATER CONTAMINATION AT THE ALLEN SITE</u>

Q. How has DEC stored CCRs at its Allen facility?

A. Historically, DEC has stored CCRs in an on-site ash basin complex consisting of: the unlined Original/Inactive Ash Basin (132 acres, built between 1956-57); also called the "Retired Ash Basin"); the unlined Active Ash Basin (169 acres, built in 1972); two unlined "Ash Storage Areas" (construction began in 1996); two unlined "Structural Fills" (34 acres, built between 2003 and 2009); and a double-lined "Retired Ash Basin Ash Landfill" (47 acres, built in 2009). (See 2015 Allen Site Assessment at 61-62.)

As I explained in detail in my testimony in the 2018 DEC rate case, key characteristics of the Allen site and its disposal areas are as follows:

- Both the Active Ash Basin and the Original/Inactive Ash Basin were constructed without liners, over unnamed tributary streams by constructing dams across the stream valleys at the Catawba River, as illustrated below:



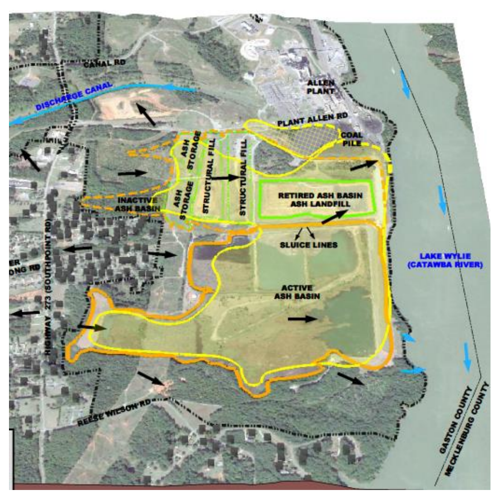
- The Original/Inactive Ash Basin and the Active Ash Basin have expanded over time. Historical aerial photographs from 1960 (three years after the original basin was constructed), 1968 (eleven years after the original basin construction), and 1978 (six years after the Active Basin was constructed) depict the growing footprints of the basins. Estimated basin perimeters are identified with red lines.

1960 Original Ash Basin

1968 Original Ash Basin

1978 Original Basin and Active Basin

2018 Contaminant Plume (yellow)



- On top of the Inactive Ash Basin, DEC constructed the (now) Retired Ash Basin Ash Landfill with a liner and leachate collection system; two dry ash storage areas where ash dredged from the Active Ash Basin was stored; and two structural fill areas (also containing ash from the Active Ash Basin).

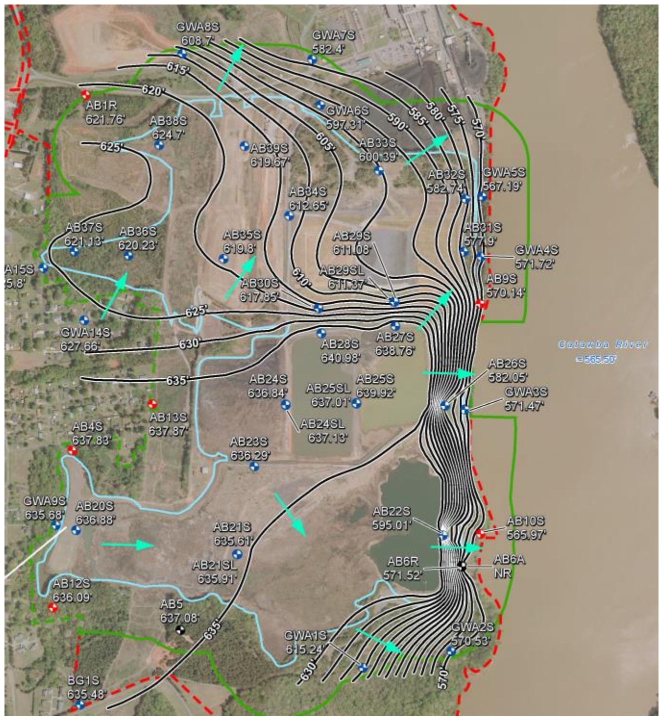
Q. As the lateral extent of the Company's Allen coal ash ponds expanded over time, did maximum depth of ash also increase?

A. Yes. As discussed before, the Company created the Allen ponds by dumping ash into existing stream beds and building earthen dams around the edges to contain the waste. Later, the Company increased the heights of the dams to increase the retention time for "settling" of particles suspended in the transport water and to increase the overall storage volume. As the dam heights increased, the depths of settled CCRs also increased, unless the impoundment was dredged.

Q. Based on your review of the Company's own reports, can you describe the site characteristics with respect to groundwater?

A. The original uppermost aquifer or water table at the site was located very close to the ground surface because the impoundments were constructed within stream channels and floodplains. Sluice water that was added to the impoundments raised the elevation of the uppermost aquifer even higher than the original ground surface in some areas. Thus, CCRs in the Inactive and Active Ash Basins are saturated by shallow groundwater.

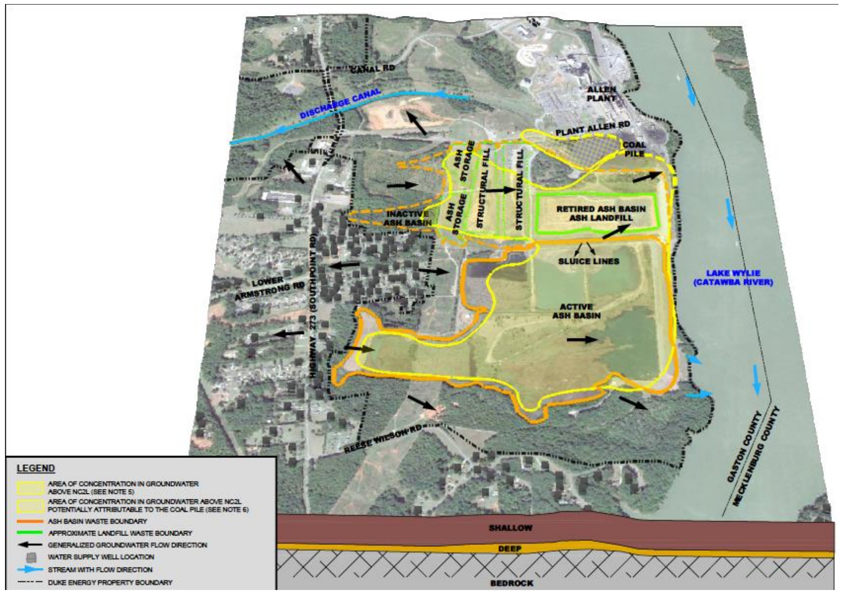
Groundwater flows towards and into the cooling water canal north of the Inactive Basin and towards and into the Catawba River/Lake Wylie to the east, as illustrated by the green arrows in the figure below (from 2015 Allen Site Assessment):



Q. Have CCR constituents in groundwater at the Allen site been found at concentrations above groundwater quality standards?

A. Yes. An investigation performed on behalf of the Company determined that groundwater beneath and around the footprints of the main coal ash ponds at the Allen site (the original pond, since decommissioned and referred to as the Inactive or the Retired Ash Basin and the Active Ash Basin) contains CCR constituents at concentrations above North Carolina 2L Standards for groundwater.

Unsurprisingly, the contamination plume closely matches the disposal area footprints, as illustrated in yellow in the figure below (from 2018 Allen Site Assessment).



Q. Is it reasonable to expect that a surface impoundment with more CCRs and with more standing water would have a higher leakage rate than a pond with less waste and water?

A. Yes, and not just because there is more waste from which pollutants can be mobilized and released. The increased thickness of the saturated and submerged CCRs and greater volumes of standing water above would create a higher "hydraulic head," leading to additional downward pressure (known as a "vertical gradient") on the underlying water table aquifer, pushing contaminants deeper into the aquifer. That increased hydraulic head would also create a radial groundwater flow pattern (known as "mounding") away from the disposal unit footprint in all directions, in addition to the preferential groundwater flow direction into the nearest stream or river. The "mounding" effect on the uppermost aquifer would then increase the gradient or slope of the groundwater, thereby increasing the velocity of groundwater that migrates away from the impoundment.

Q. Is it reasonable to assume that the extent of the groundwater contaminant plume would have been smaller if the Company had ceased disposing of coal ash in and above the Inactive and Active Ash Basins earlier?

A. Yes. The size and shape of the current contaminant plume closely mimics the size and shape of the unlined surface impoundments, which grew progressively larger over time. If the Company would have stopped sending CCRs mixed with water to the unlined impoundments and instead converted to a dry disposal system at any point during the 1980s and 1990s, for example, I would expect the lateral and vertical extent of the current plume to be significantly smaller.

In addition, had the Company switched to dry handling of ash sooner, the volume of ash that now sits in its ponds (and that must now be excavated from those ponds) would obviously be much smaller. Consequently, required corrective actions (i.e., excavation) would be less burdensome.

Q. Could the costs that the Company has incurred or will incur to excavate the Allen coal ash ponds have been smaller if the Company had switched to dry ash handling sooner?

A. Yes. Excavation costs can be understood, in large part, as a dollar-per-ton figure. Thus, there is an additional cost for every additional ton of coal ash that was disposed of in a pond and now must be excavated.

Q. Could the costs associated with groundwater monitoring at the Allen site have been smaller if the Company had switched to dry ash handling sooner?

A. Yes. A smaller, more geographically limited plume would require fewer monitoring wells. Today, more than 200 wells have been installed to monitor the extent of groundwater contamination that has spread across the Allen site.

VI. CONCLUSIONS AND RECOMMENDATION

Q. Do you have any recommendations for the Commission in this proceeding?

A. Yes. I recommend that the Commission make the following findings and give such findings due consideration as it evaluates the Company's request:

1. Historical documents, including the Electric Power Research Institute manuals, available to the Company, demonstrate that the environmental risks associated with the disposal of coal ash in unlined surface impoundments were understood by the electric utility industry in the late 1970s and early 1980s.

2. The Company's continued operation of unlined surface impoundments that were constructed directly in streams, adjacent to rivers and streams, with coal ash saturated in groundwater, without adequate groundwater monitoring for decades after the industry recognized the risks of such operation, was unreasonable and could be expected to result in the introduction of CCR constituents to surface and groundwater.

3. The Company's 1984 investigation at its Allen site that identified a leachate plume in groundwater was a warning sign and early indication that unlined surface impoundments leaked and presented risks to groundwater quality. The Company's failure to take action following that investigation was unreasonable.

4. Standing water in the impoundments, leakage of that water into the shallow aquifer below, submerged CCRs in the impoundments, and the mounding effects and radial flow conditions of the aquifer, have resulted in more widespread contamination and increased groundwater flow velocities of the contaminated

aquifer towards receptors and receiving streams.

5. Costs associated with excavation and groundwater monitoring likely would be lower if the Company had converted to dry disposal in lined landfills sooner.

Q. Does this conclude your testimony?

A. Yes.

Summary of Direct Testimony of Mark Quarles, P.G., for Sierra Club
Docket No. E-7, SUB 1214

In 2008, approximately 5.4 million cubic yards of coal ash were released into the environment following a dike failure at a coal ash pond at the Tennessee Valley Authority's Kingston coal plant. The Kingston spill brought national attention to the risks associated with the mismanagement of coal ash disposal areas, including risks of catastrophic releases as well as contamination of groundwater and surface waters. In connection with spill response efforts, I was involved with the development of a monitoring program to determine the lateral extent of the release, and I have since been involved with investigations at more than 100 coal ash disposal sites in the U.S. I have gained significant experience regarding coal combustion waste, the potential for constituents of concern to migrate in the environment, the toxicity of such constituents, and sampling programs to determine their extent in soil, surface water, sediment, and groundwater. Based on this experience, I have an acute understanding of the dangers presented by storing coal ash in unlined disposal units—and especially unlined surface impoundments.

For this proceeding, I evaluated the Company's historical coal ash management practices against the backdrop of what the Company knew or should have known, from a scientific and engineering perspective, about the dangers posed by storing millions of tons of coal ash in unlined pits in contact with groundwater and adjacent to lakes and rivers. Historical documents available to the Company demonstrate that the risks of groundwater contamination from unlined coal ash ponds were reported as early as the late 1970s and were well understood by the early 1990s. The fact that the US EPA did not finalize its federal coal ash regulations until 2014 does not diminish the fact that the Agency concluded in the 1980s that "[t]he primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause groundwater contamination." (1988 EPA Report to Congress at E-3 [PDF page 17].)

Summary of Direct Testimony of Mark Quarles, P.G., for Sierra Club
Docket No. E-7, SUB 1214

Given this understanding, the Company's continued operation of unlined surface impoundments that were constructed directly in streams, adjacent to rivers and streams, and with coal ash saturated in groundwater, could be expected to result in the introduction of coal ash constituents to surface and groundwater and was therefore unreasonable. At the very least, the Company should have conducted more robust groundwater monitoring at its coal ash sites.

Indeed, industry manuals available in the 1980s also highlighted the risks to groundwater resources and recommended that groundwater monitoring systems be installed where there was the potential for discharge of contaminants to underground water resources. A 1982 EPRI manual explained clearly the hydrogeological underpinnings of such risks, stating that: "the potential for groundwater degradation should be noted, especially when an unlined ash pond is constructed on a site with relatively permeable soils and a shallow groundwater table. . . . The existence of a constant hydraulic head (standing water) in the pond makes leachate generation and migration inevitable." (1982 EPRI Manual at 4-19.) In addition, that manual made clear the importance of adequate groundwater monitoring, stating that: "monitoring of groundwater and leachate, is nevertheless necessary to provide convincing proof of safe disposal practice." (Id.)

Nevertheless, the Company's monitoring of groundwater at its coal ash sites was far from adequate. Groundwater well sampling at the Company's Allen site in the mid-1980s revealed arsenic concentrations in groundwater beneath the site that exceeded drinking water standards. In general, the Company did not begin routine monitoring of groundwater until the early 2000s—that is, several decades after the impoundments were put into use. Detections of contaminants above regulatory standards were quick—usually within the first year of monitoring. Nevertheless, upon learning of such exceedances, the Company did not take any action to limit the introduction of coal ash constituents into groundwater or abate the contamination. Unsurprisingly, this lack of action led to widespread contamination of groundwater at every single one of the Company's coal ash disposal sites—a fact that the Company finally admitted in 2014.

Had the Company switched to dry handling of ash sooner, the volume of ash that sat submerged in the ponds for decades and that now must be excavated would be much smaller. Consequently, the costs that the Company has incurred and will continue to incur to excavate its coal ash ponds would have been smaller if the Company had switched to dry ash handling sooner. For every additional ton of coal ash that was disposed of in a pond and now must be excavated, the Company will incur additional costs. Similarly, groundwater monitoring costs would have been smaller if the Company had switched to dry ash handling sooner because properly designed landfills are less likely to leak and if so, the plume would be smaller. A smaller more geographically limited plume would require fewer monitoring wells and less associated monitoring costs.

In conclusion, the combination of the historical documents available to the Company and the Company's own identification of a leachate plume at its Allen site in 1984 should have led the Company to take action to mitigate the risks posed by its unlined ash ponds at some point in the thirty years before the adoption of the federal coal ash rule and the enactment of the North Carolina coal ash law. Instead, the Company sat on its hands. The Company's inaction resulted in more widespread contamination of the state's groundwater resources, jeopardy to present and future drinking water sources, the need for alternative drinking water supplies, and millions of tons more ash to be dewatered, excavated, and redisposed of, all driving higher cleanup and risk reduction costs.

MS. CRALLE JONES: Mr. Quarles is available for cross examination.

CHAIR MITCHELL: All right. Thank you, Ms. Cralle Jones. Public Staff, you're up first.

MS. LUHR: The Public Staff has no questions.

CHAIR MITCHELL: Okay. Attorney General's Office?

MS. TOWNSEND: No questions, Chair Mitchell.

CHAIR MITCHELL: All right. Duke?

MR. MEHTA: Good morning, Chair Mitchell. It's Kiran Mehta, and I do have a few questions.

CHAIR MITCHELL: Okay. Please proceed, Mr. Mehta.

MR. MEHTA: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. MEHTA:

Q. Good morning, Mr. Quarles.

A. Good morning.

Q. Mr. Quarles, the purpose of your testimony, as I understand it, and I'll just paraphrase, is to determine when -- and you emphasize if your testimony the word "when" -- Duke Energy Carolinas knew or should have known that environmental contamination was likely due to storage and disposal of coal ash in unlined basins.

Did I capture the purpose of your testimony correctly?

A. You did.

Q. What do you mean by the term, quote, contamination, Mr. Hart -- Mr. Quarles?

A. Contamination relates to 2L standards. It could also relate to any constituent concentration above naturally occurring background.

Q. So the way you use the term, it's essentially an increase over naturally occurring background and/or an exceedance of 2L standards?

A. So that is a common way of defining contamination. In fact, like in the CCR rule, the Company is required to evaluate constituent concentrations over time relative to other wells and naturally occurring background wells.

Q. And the CCR rule was promulgated in 2015, correct?

A. 2015.

Q. Now, on pages 3 and 4 of your testimony, you provide a list of the documents upon which you relied to inform your conclusion about when DEC knew or should have known about the likely impact of its ash storage in unlined ponds, correct?

A. That's correct.

Q. And I wanted to ask you about a few of them. But let me first see if I can understand how you believe a reader today of these documents should understand and place into context something that was written, you know, in some cases, decades ago.

So first, Mr. Quarles, if you are attempting to assess what was known or understood at some earlier point in time, would you agree that you should refrain from applying today's knowledge to an evaluation of what was known and understood during the time period that you are assessing?

A. The reports that I cited in review were reports that were available and published at the time by governmental agencies, by EPRI, by the industry in terms of what was known and what was expected to happen in the future regarding coal combustion waste disposal.

Q. I understand that, Mr. Quarles, but my question was slightly different. And let me try to restate it.

If you are attempting today to assess what was known or understood at some earlier point in time, would you agree that you should refrain from applying today's knowledge to an evaluation of what was known and understood during that period of time; rather, you should apply that period's knowledge about what was known and understood?

A. So I am -- I am reviewing documents that were written in the late '70s, early '80s that were written at that time, and, of course I was not employed in a capacity as a scientist in the late '70s, early '80s. So my work was evaluating what was known at the time, and those documents describe what was known in terms of the risks associated with coal combustion waste disposal.

Q. Well, I guess my question to you, Mr. Quarles, is as you read them today, are you reading them today through the lens of today, or are you reading them today applying the lens of the late '70s or the 1980s?

A. I am reading them as a scientist. And what information that is available in the documents, putting myself in a position, if I was a consultant back in the '70s, or if I did work for the Company back in the '70s, what kind of data would I find to be important to make decisions at that time.

Q. Okay. So if I understand you correctly, Mr. Quarles, what you're trying to do is read the documents that were written in some cases, you know, 30, 40 years ago through the lens of someone reading them at that time?

A. You trailed off.

Q. Let me try it again. If I understand you correctly, Mr. Quarles, you are reading those documents obviously in present day, but trying to read them through the lens of somebody who was reading them or would have been reading them back at the time that they were written and published and available for review by whoever was reading them; did I capture that correctly?

A. Yes. You're reading them as if somebody was reading them back in the '70s and '80s, and what the conclusions and what the data said as a whole means.

Q. Have you reviewed the testimony of Marcia Williams, Mr. Quarles?

A. I reviewed her rebuttal testimony.

Q. Yeah, I think that might be the only testimony that she -- well, I think she also had some supplemental rebuttal, but that deals with Mr. Hart, not you.

The -- on page 67 of her testimony, right at the top of the page --

A. Okay. Is this the PDF page or the hard copy page of the testimony?

Q. I guess it would be the hard copy page.

A. Okay.

Q. And in her testimony -- it's actually the top of page 68, see the reference is -- are you there?

A. I am, yeah.

Q. Okay. She references what she refers to as the, quote, weight of evidence approach; do you see that?

A. I do.

Q. Is that the approach that you also applied in your review of the historical documents that you reviewed that are listed on pages 3 and 4 of your testimony?

A. I didn't refer to my review as a weight of evidence approach. I reviewed those documents and provided my opinion and interpretation of those documents.

Q. Okay. But you didn't -- you didn't follow what she calls the weight of evidence approach?

A. I don't know what her -- how she defines a weight of evidence approach.

Q. Well, I guess she defines it starting on the preceding page. And if you could just read -- you can just read it to yourself, we can all read it ourselves as well. Starting on page 67, line 12, and going on to the top of page 68. I want to know if that is the approach that she outlines called the -- that she calls the weight of evidence approach, if you used that approach.

A. (Witness peruses document.)

Yeah. On page 67 she talks about specifically:

"It's key to recognize that a single research study or a statement on a report does not represent consensus that a particular activity has -- is or is not reasonable."

And then she goes on to say that Mr. Hart, Junis, and I selectively refer to various documents weighing the broader -- without, in my opinion, weighing the broader set of available knowledge.

Q. And the -- weighing the documents within the broader set of available knowledge is what she calls the weight of evidence approach, correct?

A. Yeah. And I would say that I followed the weight of evidence approach, because I had authoritative numerous documents that were specifically related to disposal of coal combustion waste. Information that was available to the industry and written by the industry, and information that was written by EPA specifically related to coal combustion waste at that time.

Q. So would you agree that you, in fact, were trying to follow what Ms. Williams calls the weight of evidence approach? You might call it a different term, but that's what you were trying to do?

A. So what I did was I reviewed numerous documents that were written at the time specific for coal combustion waste.

Q. And does that mean that you were trying to follow what Ms. Williams calls the weight of evidence approach?

A. Whatever you want to call it. Weight of evidence is there were numerous documents that all supported the same conclusions relative to the risk associated with coal combustion waste disposal.

Q. Would you agree that when one looks at a particular publication or study done in the past, that one should try to place that study in the context of what else was going on and what else was known at that time?

A. That's a fair statement.

Q. And would you also agree that it is inappropriate to take a little snippet of a study out of the context in which the study was developed, published, and presented?

A. The -- as you call it, the snippets -- snippets there are important sentences that are included in the documents related to the risks associated with coal combustion waste disposal.

Q. So you would stay that it's appropriate to use a snippet in -- with reference to how you are presenting your testimony, you know, again, relying on these past documents but presenting a point of view with respect to those documents in your testimony today?

A. It's important to review all of the findings of the documents, in addition to bringing out those points regarding the purpose of my testimony.

Q. Okay. But it would be inappropriate, would it not, Mr. Quarles, to take one of those snippets and then portray it today as supporting some proposition on which the study came to a contrary conclusion; is that correct?

A. I would tend to disagree with that statement. Sometimes these studies, for example, they would look at -- when I say some of the studies, particularly some of the studies that Ms. Williams cited in her testimony. Her studies looked at the use of surface impoundments, for example, as a whole around the country, not just coal combustion waste disposal. So she looked at impoundments that were related to oil and gas, or municipal wastewater, or any sort of industrial-type scenario.

And so, for example, if there was a conclusion out of a report, that was a conclusion that said the risks were minimal, or there was little risk, or no harm, whatever you want to call those kinds of paraphrased conclusions, I would tend to disagree. And actually those documents -- many of the documents would also have other snippets, as you call it, that talk about, for example, a larger impoundment in the greater scheme of things has a greater opportunity for leakage as compared to an impoundment that's less than one acre, for example.

So the context is important in the conclusions that I brought out relative to the surface impoundments that were typical of the Company.

Q. Well, I guess to put maybe a finer point on my question, Mr. Quarles, perhaps it was too broad a question.

If you had a study, for example, that was done in 1980 that concluded the sky is blue except sometimes at sunset it kind of looks red and gold, it would be inappropriate for someone to come along decades later and say only that that study concluded that the sky was red and gold?

A. If I was a scientist in the early 1980s like I am now, I would review the documents in the same way. And, you know, just to use your analogy the sky is blue, let's talk about the A.D. little report as an example. It did come to the conclusion that, you know, the risks were minimal nationally for the six -- using the six sites that were evaluated, but let's put it in the context of six sites, and there were approximately 500 coal combustion waste impoundments around the country. Those six sites represented 1 percent approximately, of the total. And then when you actually get back into the details of the report, was not very flattering at all about what was actually going on at plant Allen as one of those six sites.

So, as a scientist, I reviewed the report in the context of the broader conclusions, not just the -- what was written in the abstract or the findings and conclusions at the end.

Q. And I think you did mention this, but plant Allen was one of the six sites out of 500 or however many there were nationwide, correct?

A. That's right.

Q. That was the focus of the Arthur D. Little report?

A. There was one. The Allen site was one of the six, yes.

Q. Okay. Now, Mr. Quarles, let's actually talk about some of the more -- some -- more specifically about some of the documents that you've cited.

And on page 12 of your testimony, you reference and talk about a manual authored by the Electric Power Research Institute, or EPRI, in 1981, correct?

A. That's right.

Q. And that document is one of the ones that we have marked as a joint exhibit, and I believe it is Joint Exhibit Number 7. And you can certainly refer to Joint Exhibit Number 7, or there are multiple copies of the EPRI 1981 manual floating around, and whichever one you want to refer to is fine.

And you note, on page 12 of your testimony, the concern raised in the manual about the potential for heavy metals to leach into the groundwater system and contaminate present or future drinking water sources, correct?

A. That's right.

Q. And, Mr. Quarles, this particular manual, the 1981 EPRI manual, was published by EPRI for use in designing new landfill facilities; is that correct?

A. That's right.

Q. And Ms. Williams indicates in her testimony, I think it's on page 77 -- and you can certainly look there if you like, but you may just remember it -- but she indicates that the 1981 manual was written in anticipation of EPA regulations that, in fact, were never promulgated.

Do you recall that in her testimony?

A. I do.

Q. Do you agree with her testimony?

A. That's right.

Q. So, for example, Mr. Quarles, on page 12, lines 8 through 16 of your testimony, you list a whole series of things that the EPRI 1981 manual says should be done in connection with new landfills that are developed post publication of the 1981 manual, correct?

A. Yes.

Q. And did those -- did those requirements that are laid out on page 12, lines 8 through 16 of your testimony ever actually become requirements that anybody had to follow?

A. Well, according to EPRI, they referred to at least a couple of those standards as being applicable -- already applicable in North Carolina at the time. For example, not building solid waste disposal facility in a flood plain, or separation between the waste and the water table. So the context of the 1981 EPRI document certainly laid out -- if you were not schooled, educated, or experienced in the risk associated with unlined impoundments in the late '70s, early '80s, this document, although for a new facility, should have informed you that there are risks associated with unlined disposal.

And it talked very methodically about the processes that you should go through on determining whether or not your -- whether or not you have any contamination. For example, I list like eight or nine different factors, if you will, on establishing background data quality -- groundwater quality, the depth, direction, rate of flow, hydraulic conductivity, the attenuating capacity of the soil, the separation distance between the bottom of the waste and the uppermost aquifer.

So it should have spurred that thought process to say if I don't -- if I have an existing facility, is it -- have I done that evaluation to know whether or not my -- my unit is leaking to groundwater. And on that same page, I make reference to a 1982 EPRI document which was a follow-up document for upgrade. And it, again, talks about that same thought process of you should consider an upgrade by following the steps of a groundwater evaluation to know whether or not you're contaminating the underground source of drinking water.

Q. Yeah. We'll get -- I promise you we will get to the 1982 EPRI document shortly. But let me just stick with the 1981 one for a moment.

Mr. Quarles, do you have any information that suggests that, when Duke Energy Carolinas built a new landfill after 1981, that it did not comply with whatever the regulation -- regulatory framework was with respect to building that landfill?

A. When you say "landfill," are you talking landfill, or are you meaning a surface impoundment, or both?

Q. I'm talking about a landfill, since the 1981 document is specifically dealing with landfills.

A. Ask your question again, please.

Q. Do you have any information, Mr. Quarles, that suggests that, when Duke Energy Carolinas built a landfill after 1981, that Duke Energy Carolinas did not comply with whatever regulatory framework governed the development of that landfill?

A. So some of the landfills, like the retired ash basin landfill at plant Allen, had a liner, right. Some of the other landfills perhaps do not have a liner. And then if you didn't have a groundwater monitoring system of a landfill water surface impoundment until the, you know, mid, what, 2011, voluntary monitoring perhaps began in 2005, 2006, then obviously they would not be following the recommendations on establishing groundwater quality, which is a component of design and operation of a landfill.

Q. Well, my question was a little different, Mr. Quarles.

Do you have any information that suggests that, when Duke Energy Carolinas built a landfill after 1981, that it did not follow whatever the regulatory framework that governed the building of that landfill?

A. And which landfill are you referring to?

Q. Any landfill.

A. Which landfill did they build post 1980?

Q. Well, for example, Mr. Quarles, we know that, as a result of the Belews Creek -- Belews Lake incident in the mid-1980s, that Duke Energy Carolinas changed its operating process, and instead of sluicing fly ash into the ash pond, it started to handle fly ash on a dry basis and built a landfill to store that fly ash, correct?

A. I did hear that yesterday in the testimony of Mr. Hart, but I have not investigated the details of Belews Creek.

Q. Okay. And so, presumably, this -- well, the mid-1980s is after 1981, correct?

A. It is.

Q. And so if they built a landfill to handle the fly ash that was produced as part of the operating process at Belews Creek, they built a landfill, as far as you know, in complete compliance with whatever the regulatory framework was for building that landfill?

A. I can't -- you know, I can't say as far as I know, because I haven't investigated those landfills. The 1981 EPRI document that I referred to, really the context of that was that if you're going to do this sort of evaluation and consider those eight or nine factors for a landfill, you should especially be considering those factors for surface impoundment because the opportunity for leakage is much greater.

So that -- that is why the '81 EPRI document is so very much relevant. And, in fact, if you look at the bottom of my testimony page 12 -- and again we'll get to it, the 1982 EPRI document -- but it says:

"Inadequately lined ponds provide a greater opportunity for groundwater contamination because the soil immediately below the pond is always saturated and under a constant head of pressure from the overlying water. Consequently, seepage may be constant and in greater volume than leachate from a landfill."

So what that means, if I am a manager in the company that is responsible for CCR disposal, that kind of comment and the eight factors of evaluating the groundwater quality in the '81 document should have --

should have raised some flags and required the Company to ask really hard questions about whether or not my unlined surface impoundments are leaking.

Q. Well, since you're already at the 1982 document, why don't we just go to the 1982 document, Mr. Quarles. And I believe that is Joint Exhibit 8. And it is certainly a lengthy exhibit. I think it's about 500 pages or so.

And first, just to level set us, Mr. Quarles, I think you mentioned this earlier, and do you -- are you actually looking at what we've marked as the joint exhibit, or are you looking at a different version?

A. I don't have that joint exhibit open. You haven't asked me to review a certain page, so if you would like me to do that, I would.

Q. Yeah. I mean, if you're in the joint exhibit, since they have a specific identifying document page at the top of the -- at the top, primarily because all of these came from the appellate record, it would be page 1,455. If you're not in the joint exhibit, it is page romanette v.

A. So if I'm in a hard copy, what page would you like me to look at?

Q. It's the little Roman numeral v.

A. Of the -- I'm sorry, the '82 or the '81?
Q. '82.
A. Oh.
(Witness peruses document.)
So the page numbers of the '82 document are, like, 1-3, 2-14.
Q. Yeah. Well, this is before you get to the 1- --
A. Oh, okay.
Q. It's in the -- sort of in the preliminary stuff. It's called -- the title of the -- or the title at the top of the page is "EPRI Perspective."
A. Yes, sir, I see that.
Q. And in the section right below EPRI perspective, it talks about the project description, correct?
A. It does, yup.
Q. And it says this document is one of a series of manuals, and the '81 document was in that series, correct?
A. Yes, sir.
Q. And it's actually mentioned there, the -- I think that's the coal ash disposal manual, correct, is the 1981 document?

A. Yeah. Coal ash disposal manual, second edition.

Q. Okay. And it goes on to say that:

"Whereas the aforementioned manuals," which would include the 1981 manual, "are intended for use in designing new disposal facilities, this manual," the 1982 manual, "is primarily intended for upgrading existing waste disposal facilities."

Did I read that correctly?

A. Yes, you did.

Q. So if you're interested in EPRI's view on upgrading existing facilities, this is the one you should be looking at as that early 1980s reader or engineer trying to figure out what they're supposed to do, correct?

A. Yeah. And I would add to that, is -- part of the context of this upgrade document is to assist a utility manager to decide whether or not he or she needs to upgrade a disposal facility. So that's where it talks about -- you know, like on page 12 in my testimony, and this specifically mentions it for that purpose, that inadequately lined ponds provide a greater opportunity for groundwater contamination. It's always saturated, it's under constant head of pressure, and seepage may be constant and in greater volume.

So part of that manual was meant to enable a utility manager to make decisions on whether or not it contaminated the groundwater and whether or not they should upgrade because of that greater opportunity for leakage to a dry disposal facility.

Q. Okay. And your testimony goes on on page 13 to make additional reference to more specific pages of the 1982 EPRI manual, which is Joint Exhibit 8, correct?

A. Yes.

Q. And you cite to pages 4-1 and 4-2, correct?

A. I do.

Q. And again, if anybody is following along with me, joint exhibit, those pages are DOCX 1529 and 1530. But if you just -- if you've got the 4-1 and 4-2, we can certainly use those.

A. Okay.

Q. And at the top of 4-1, there is a paragraph under introduction that I think is what you were alluding to.

That is the utility environmental engineer or other individual responsible for waste disposal needs to figure out, you know, what's coming down the pike and does my facility comply, right?

A. Yes, sir.

Q. And that last little parenthetical says if the sites are ultimately required to comply with whatever the new regulations that are coming down the pike are, correct?

A. Yes, sir.

Q. And you then, at the bottom of page 4-1, I think you quote the language from there in your testimony on page 13, correct?

A. I did quote from that page; yes, sir.

Q. So you indicate that potential deficiencies in utility waste disposal practices may be defined by two sets of standards, right? And those two sets of standards are what is down at the bottom, those two bullets at the bottom of page 4-1, correct?

A. Yes, sir.

Q. And the first one is the disposal practice does not comply with, you know, whatever the specific rules and regulations are, correct?

A. Yes, sir.

Q. And then the second one is the site has the potential to contaminate the environment, correct?

A. Correct.

Q. So, Mr. Quarles, what did the authors of the EPRI manual mean by "the site has the potential to contaminate the environment"?

A. Well, if it's an unlined surface impoundment that receives millions of gallons of water every day in a stream valley next to a water body, clearly the site has the potential to contaminate the environment.

Q. Well, I guess by my question, Mr. Quarles, what I'm asking is, do you know whether the authors of the 1982 EPRI manual apply the same definition of contaminate that you do, that is any level above background?

A. I don't know how they define contamination, but, you know, I've been in the environmental consulting business for over 30 years, and the interpretation of contaminate, whether or not -- particularly related to whether or not a facility is leaking and has the opportunity to contaminate the environment, is really -- it's really -- it hasn't really changed in the 30-plus years.

Q. Well, again, if you think back to Ms. Williams' testimony, Mr. Quarles, she made a distinction between contaminate, meaning any level above background, and environmental harm, meaning somebody could actually be hurt by it, correct?

A. I do remember her making that statement.

Q. Okay. Well, do you know if the authors of the 1982 EPRI report used the word contaminate in the sense of any level above background, or did they use the word contaminate in the sense of something that could really hurt?

A. So let's go back to the first part on that page 4-1. And you made reference to this sentence. "If the sites are ultimately required to comply with the regulation." So the 2L regulation did apply, and I think it was promulgated in North Carolina in 1979. So the 2L standards applied in 1979 and certainly in 1982 with this upgrade manual. So we need to understand that those standards were there, and the state had established those standards, and they were -- at a minimum, they have to be at least as stringent as the EPA standards and perhaps -- or even more stringent for North Carolina situation.

So in terms of contaminate the environment, we first need to remember that the regulators have already established those standards on what is an acceptable or not concentration of groundwater; and then secondly, contaminate again could be whether or not there's evidence of leakage beyond background.

So it's -- certainly, the prevailing regulation at the time was the 2L standard.

Q. Mr. Quarles, is it your testimony that the authors of the EPRI 1982 report had in mind the 2L standards when they wrote this report?

A. I can't speak for the authors of the report, but I can tell you that these documents were meant to discuss CCR disposal and risks associated with unlined disposal and the opportunity to contaminate groundwater. That's very consistent in all of the documents.

Q. Okay. Mr. Quarles, if you would -- we'll come back to pages 4-1 and 4-2, but if you would go to -- at the very beginning of the document before the Arabic-numbered pages start, Roman number VI.

A. Roman numeral number VI?

Q. Yes. And for anybody following along in the in the joint exhibit, that would be DOCX 1456.

And you see the section on that page that's headed "Project Results"?

A. Yes, sir.

Q. And the second paragraph there under that page -- under that heading reads as follows:

"Regulations governing the disposal of utility wastes are in a state of suspension at this time. Congress, in the 1980 amendments to RCRA requested a detailed study of the effects of utility waste disposal practices. And the EPA has a multimillion dollar project underway to address some of the questions. The answers are not expected to be known until late 1983. Until that time, there will be no firm design or performance standards applicable to utility waste disposal that can be applied with confidence by the industry. At the present time, state standards for nonhazardous wastes, which are also undergoing change -- undergoing change, apply to utility waste disposal. For these reasons, it may be premature for any utility to embark on a program to update their existing disposal facilities."

Did I read it correctly?

A. You did.

Q. Okay. Mr. Quarles, the authors of this manual were essentially telling the reader, changes in the rules are coming, we want you to get ready for those changes, but don't do anything just yet because they're coming. Is that what that paragraph said?

A. It does say that changes are coming, and it may be premature. I think "may" is a very key word. And that was the whole idea of the EPRI documents is that -- is that you're not going to be able to flip a switch and snap your finger and immediately make decisions without collecting information. And so what these documents, particularly the '82 document on the upgrade, is that you need to start now to assess your facilities on whether or not you're -- you have an opportunity to be out of compliance or contaminate the environment, if you will.

And one of the most important things here in the first part of that paragraph, it says:

"Need to remember that there may not have been design and disposal standards on how to design a CCR disposal facility, but RCRA, itself, and the requirement that you not pollute groundwater has been in effect since 1979."

So while there may not have been design standards for how to build and design a CCR disposal unit, the requirement to protect groundwater has been there since 1979, right. So with that in mind, I think the terms -- the only way to provide convincing proof that you're meeting the 1979 RCRA groundwater standard is to install wells. Wells are necessary, according to EPRI.

So while there may not have been national design standards for CCR landfills, there was certainly a requirement to comply with the groundwater standard.

Q. And when you say "groundwater standard," are you speaking of the federal RCRA standards, or are you speaking of the 2L state standards?

A. So they were both promulgated, my understanding, in 1979, so both would apply.

Q. Okay. If you go back, Mr. Quarles, to pages 4-1 and 4-2.

A. Okay.

Q. And on page 13 of your testimony, you quote from 4-2. That quote, if -- well, the paragraph on 4-2 that you're quoting from starts "if evidence of contamination problem exists."

A. Are you reading from my testimony or are you reading from page 4-1?

Q. I am sorry, that was a confusing question. I'm actually reading from page 4-2.

A. All right. Okay.

Q. And the paragraph that you quote from in your testimony says, "if evidence of contamination problems exist."

A. Uh-huh.

Q. Is that right?

A. Yes, sir.

Q. And there again, you don't know in what sense of the word contamination the authors of the EPRI report used the word contamination, correct?

A. That is correct. The context of determining whether or not there's evidence of contamination, certainly according to EPRI, you need groundwater monitoring wells for convincing proof for what they call inevitable and constant seepage. So if evidence of contamination problem exists, the only way that you will know with convincing proof is to have a groundwater monitoring system.

Q. And then the part in your testimony that you do quote is down at the bottom of that paragraph.

"So if evidence of contamination problems exists, then an engineering assessment of site adequacy must therefore address; one, whether the operation complies with prevailing regulations; and two, whether the site poses a threat to the local environment."

Do you see that?

A. Yes.

Q. And then that is the part that you quoted in your testimony, correct?

A. It is; yes, sir.

Q. And again, the authors don't tell us what they mean by a, quote, threat to the local environment, do they?

A. Perhaps they do in the other parts of the document.

Q. Well, if you look immediately above those words, there may be a clue, because they talk about current federal regulations promulgated under Superfund authority ultimately hold the operator liable for environmental degradation regardless of what regulations applied or who permitted the facility, correct?

A. Yes, sir.

Q. Now, the Superfund law is what Congress enacted following the Love Canal disaster to deal with hazardous waste dumps, right?

A. Yeah. Uncontrolled -- initially it was for these uncontrolled hazardous waste sites, correct.

Q. Now, Mr. Quarles, there are no Duke Energy Carolinas ash basins that are Superfund sites, are there?

A. I'm not aware, but I haven't researched to know if they are.

Q. Well, as far as you know, there are no Duke Energy Carolinas ash basins that are Superfund sites, correct?

A. Yes, as far as I know.

Q. But in any event, you indicate, again on page 13 of your testimony, that through the EPRI 1982 manual, the utility industry should have known that it should engage in groundwater monitoring, right?

A. I did.

Q. And you've stated that repeatedly this morning, correct?

A. I did.

Q. And, Mr. Quarles, you know that, when this manual was published by EPRI in 1982, Duke Energy Carolinas was already engaged in a multiyear study of the impact of coal ash basins on groundwater, focused specifically on the Allen plant, but intended to apply to all of DEC's power plants; isn't that correct?

A. I am aware of the 1984 document, yes.

Q. Are you also aware that it was not just DEC's own internal investigation at plant Allen, but also an EPA investigation under contract with Arthur D. Little and an EPRI investigation under contract with another contracting environmental entity altogether, all in the same general time frame?

A. Same general time frame, yes.

Q. And the Duke study indicated -- which is Joint Exhibit 9; we can certainly look at it if you'd like -- but indicated that this groundwater monitoring program had been in place since 1978, correct?

A. That's right, at plant Allen.

Q. At plant Allen. 1978 is four years before 1982 EPRI manual was published, correct?

A. Before the upgrade manual in 1982, yeah.

Q. And the report of that study, which again is Joint Exhibit 9, concluded when it was published in 1984, two years after the 1982 EPRI manual came out, that there was no significant impact on groundwater, didn't it?

A. Are you referring to the internal Duke 1984 or the A. D. Little report? I'm sorry.

Q. I'm referring to the 1984 Duke report.

A. Okay. I'm sorry, repeat your question.

Q. The 1984 Duke report, which is Joint Exhibit 9, and was published two years after the EPRI manual, 1982 EPRI manual, it concluded that there was

no significant impact on groundwater, didn't it?
    A.   Maybe you can refer me to that conclusion. I have a hard copy, if you'd would like to tell me what page that is.
    Q.   I will -- I will find it. It's Joint Exhibit 9, and if anybody's following with the joint exhibits, it's DOCX 9395. It's an unnumbered page directly in front of the introduction on page 1, and the page is headed "Executive Summary."
    A.   I see that, yes.
    Q.   And the executive summary -- what is an executive summary, Mr. Quarles?
    A.   It's supposed to summarize what the author feels are the main conclusions of the report.
    Q.   Okay. And then, so the executive summary starts:
          "Beginning in 1978, field and laboratory investigations of the composition of leachate and its behavior in the disposal environment were conducted by Duke Power and outside contractors," correct?
    A.   Yes.
    Q.   And the outside contractors would include the Arthur D. Little contractor and whoever did the work for EPRI, correct?

A. I believe -- yeah. In the back, starting on page 31, A. D. Little is shown as the prime contractor.

Q. Okay. And the executive summary continues sort of in the middle of that paragraph:

"Groundwater monitoring in 13 test wells installed by Duke Power around a retired and active ash basin found, over a four-year period, that drinking water quality was maintained in the wells downgradient of the sites after groundwater stabilization had occurred following well installation."

It goes on to say in the next sentence:

"Additional groundwater monitoring and soil testing from the same sites done by an EPA contractor," and that's Arthur D. Little, "also found the downgradient groundwater to be drinking water quality, and suggested the high ion exchange capacity of the soil lining the ash basin to be the mechanism preventing migration of soluble metals from the ash basin."

Did I read that one correctly?

A. You did.

Q. And then the executive summary concludes:

"These field and laboratory studies confirm that wet disposal of coal ash by Duke Power has no significant impact on groundwater," correct?

A. Correct.

Q. Mr. Quarles, let's take a look at a couple of other documents on that list.

A. Can we talk -- would you like to talk more in depth about the 1984 study?

Q. I have no further questions to you on the 1984 study, but I'm sure, if your counsel would like to ask you more questions about it, they are free to do so.

A. Well, what I'd like to do is I would like to respond to the executive summary, the conclusion. So in the beginning of this testimony today, you asked me if you read a summary and conclusions, should you -- should you believe all of that information that's in that one-page executive summary, as you have here. And I responded by saying, well, many times if you look further back into the document, you'll find that it's -- the executive summary really doesn't give the whole picture.

And I can walk you through why this executive summary doesn't give the whole picture relative to the findings. And, for example, the second sentence, the leach test.

Q. Before you go further, Mr. Quarles, let me just ask you this, and you can certainly answer it as fully as you want.

Are you saying that the -- that last sentence in the executive summary is incorrect?

A. Well, what I'm saying is that they have some bad information. For example, to keep it really simple, midway in the paragraph, all results -- "toxic metals to be nonhazardous according to EPA criteria." And what that means, nonhazardous --

Q. Where are you? I'm sorry.

A. There's no line numbers, but I'll count them. One, two, three, four, five lines down beginning with the word "all" on the right-hand side.

Q. Okay. So the sentence immediately above. Okay. I got you.

A. So what that means is that the nonhazardous, according to EPA criterion -- and they make reference to the EPA and ASTM protocols on the leach test. And leach tests were designed to determine whether or not a waste is a characteristically hazardous waste by definition according to EPA, not -- not which would regulate it as a subtitle C waste versus a subtitle D.

So just because it's a nonhazardous waste doesn't mean that it doesn't have hazard constituents and hazards and risk associated with it. And the next sentence:

"Groundwater monitoring in 13 test wells installed by Duke found over a four-year period that the groundwater quality was maintained."

All right. So a couple of points to that. The groundwater testing results showed that we had arsenic in well number 4 up to 112.5 part per billion. That's over 10 times the current arsenic standard, and over two times the arsenic standard at the time, which was 50. All right. That's --

Q. Where was groundwater monitoring well number 4, Mr. --

A. It was -- it was in the area of the inactive basin. The other thing that I think is especially relevant, if you go to page 23 of the hard copy, 23, there's a Table 7. And remember, they talked about they make that conclusion based on the results of 13 test wells. And most importantly, as it relates to the Table 7, as far as being a good scientist and relying upon an executive summary, is that you'll see that the wells -- 6 of the 13 wells were finished what they call below the perched water table.

So the relevance of what that means is it hasn't changed for the 30-plus years that I've been an environmental consultant. EPRI pointed out the two most important aspects of a groundwater monitoring program are the locations and depth of the wells. So if you installed 6 of your 13 wells below a perched water table, that implies that you've installed your wells too deep and not closest to the bottom of the ash pond of the part of the aquifer. Particularly when we recognize that it ash is sitting in the water table. So from a groundwater monitoring design program, you would want to monitor the uppermost portion of the uppermost aquifer.

And then if you refer for simplicity purposes to try to illustrate that, there is a diagram on page 28 that I included in my testimony, but it refers -- and it illustrates a leachate plume coming from the ash basin, shows the groundwater flow, but what it doesn't show in those wells is the screened interval.

So what they're implying -- or what they're saying in Table 7 is that the screen portion of the interval that they're collecting water from is below the uppermost portion of the aquifer. So, therefore, it's quite possible that they're not reporting the highest concentrations of constituents. All right.

So the -- you know, again, when you read beyond the executive summary and get into the details as a scientist of what really matters, that would -- that would have raised a flag -- red flag to any competent engineer or hydrogeologist back in the early '80s.

Q. Did it raise a red flag to Arthur D. Little?

A. Apparently not. And we -- I'd love to talk to you about the A. D. Little report, but if you'll let me proceed. For the '84 report, it goes on to say:

"Also found that the downgradient groundwater to be of drinking water quality and suggested the high exchange capacity of the soil lining to be the mechanism preventing migration of soluble metals from the ash basin."

Q. And, Mr. Quarles, let me just interrupt you just there for a moment, but that suggestion came from the Arthur D. Little report; did it not?

A. Perhaps it did. I guess my point is, suggested is much different than concluded.

The other thing that I would add is that one of the purposes of this '84 investigation was to determine leachable -- it's on page 14 of the hard copy document. The objectives of the monitoring program were to provide data documenting the condition and quality of the groundwater at the ash basin site. Number 2, predict and assess the effects on the adjacent groundwater, chemical quality of adjacent groundwater. And then number 3, determine the projected length of time that the ash basin substrate; i.e., the soils, can retain leachate. And that gets into the argument about attenuation of soils, of contaminates. And then number 4, predict and calculate the life expectancy with respect to the ion exchange capabilities of the underlying soils.

What this report did not do -- that's why they said "suggested" -- is that they didn't make any conclusions about the length of time that the substrate/soil can retain the leachates. Nor did they predict or calculate the life expectancy of that attenuation.

So with that said, when you read the details of this report, if you only read the executive summary, it sounds like there's no harm, no foul; but a competent engineer, or environmental manager, or hydrogeologist would have made the same evaluation and conclusions that I just made.

And so now when we're talking about A. D. Little, the A. D. Little report again refers to this, and there's been, you know, some discussions about soil attenuation capacity, and that the Piedmont soils are very clay -- clayey soils. But the A. D. Little report for plant Allen actually refers to the soils as sandy soils.

And then just as a review for this testimony, I looked back at a comprehensive site assessment, CSA that was done by HDR in 2015, and they create a conceptual site model for plant Allen. And again, the predominant type of soil at the site plant Allen is a sandy, gravelly soil, right.

So in terms of, you know, this prediction, they weren't able to make a prediction because their leaching tests didn't -- didn't match the results of the groundwater monitoring, and that's perhaps because the wells were too deep. And -- and what, in fact, is more prevalent is that there's less clay and more sandy soils, according to HDR, the consultant that recently completed the comprehensive site assessment.

So the body of work of this '84 document is -- it's impressive if you want to just read the executive summary, but if you read the details behind it, it has lots of technical problems.

Q. So, Mr. Quarles, you would disagree with the conclusion drawn by the report that there is no significant impact on groundwater from the operations of the ash basin?

A. I would. I mean, the data in this report shows that arsenic was over 10 times higher than the current drinking water standard.

Q. And you would disagree with whatever the conclusions -- the similar conclusions made in the Arthur D. Little report, correct?

A. So when we talk -- when you're ready to talk about the A. D. Little report, it's a very similar -- it's a very similar situation where the executive summary is. If you only read the executive summary, then you can be led to believe that all is well and there's no risk associated with it. But when you dig into the details of the A. D. Little report, similar to this 1984 Duke document, there's all kinds of limitations, and exceptions, and generalizations that are made by A. D. Little that I don't agree with.

Q. Okay. I think we understand that you don't agree with those conclusions, and we can move on.

A. Okay.

Q. But I did want to talk to you a little bit about the -- about -- I think there were a couple of your documents that relate to the EPA. Let me see if I can locate where they are referred to in your testimony. Bottom of page 11.

A. Okay.

Q. And you refer to two different EPA reports. One published in 1980, and then the 1988 report to Congress, correct?

A. I did, yeah.

Q. And the 1980 report -- again, they're both in the joint exhibits. 1980 report is Joint Exhibit 6, and looks like sort of a joint effort by the EPA and the TVA, correct?

A. That's right.

Q. And it's called "Behavior of Coal Ash Particles in Water," correct?

A. Correct.

Q. And, Mr. Quarles, you site a couple of sentences from the report that indicate impacts on groundwater, or refer to impacts on groundwater, correct?

A. It did.

Q. This particular report is really focused on ash pond effluents, correct?

A. It is talking about pond effluents, standing water in the pond.

Q. And, Mr. Quarles, if you -- just so we can get our terms defined -- if you look in the DEC exhibits to Exhibit 16.

A. What document is that?

Q. DEC Cross Exhibit 16.

A. (Witness peruses document.)

What is -- what is the title of that document?

Q. Let's see. It is your testimony, or a portion of your testimony in the prior Duke Energy Progress proceeding. So it's transcript Volume 13, Docket Number --

A. So under DEC cross exhibits -- what is the -- what exhibit number am I looking for?

Q. 1-6, 16.

A. (Witness peruses document.)

Is that a -- it looks like at the top it says Dobbs Building, Raleigh, North Carolina?

Q. That would be it, yes; you're right.

A. Okay.

MR. MEHTA: Madam Chair, if we could, let's go ahead and mark this as DEC Quarles Cross Exhibit 1.

CHAIR MITCHELL: The document will be so marked.

(DEC Quarles Cross Examination Exhibit 1 was marked for identification.)

Q. And just to get us straight here, Mr. Quarles, I'm looking at page 196 of the transcript. Are you there?

A. No. I'm trying to -- it's --

Q. If you're looking at it on a PDF, it's probably PDF page 14.

A. So I haven't downloaded this. Hold on. What page did you say?

Q. The page number of the transcript page number is 196.

A. So I'm looking at -- mine shows that there are 27 pages. What --

Q. Right. If you're looking at it in the PDF form on your computer, it's probably going to be PDF page 14.

A. 14. Okay.

(Witness peruses document.)

Okay.

Q. And, again, I'll represent to you, Mr. Quarles -- and this is actually a very simple question, so maybe we didn't have to go through all of this setup -- but the -- on page 196, you are answering questions that were posed to you by Chairman Finley in the DEP -- the last DEP case, Docket Number E-2-1142. And in the -- starting at line 7, you are answering one of Chairman Finley's questions and you talk about the reasons utilities sluice.

And you state that the reasons utilities sluice is, quote, to take an ash that's created at the boiler, then mix it with water, then they pump it to a pond so that the solids can settle out. And then the water, some of it will evaporate, some of it seeps into groundwater, and some of it overflows through a permitted, regulated, what we call an outfall to a receiving stream.

A. Correct.

Q. Chairman Finley then asks, "Is a technical name for whatever that is discharged, that is that's going through the outfall to a receiving stream," and you indicate, "We call it effluent," correct?

A. That's right.

Q. So I apologize. That was a long setup for probably what was a very simple question.

So the 1980 EPA TVA report that you reference at page 11, which is Joint Exhibit 6, deals with effluent, correct? I mean, I'm looking, for example, at page 1, I believe.

A. So -- yeah. The report -- the report was written to primarily talk about -- it's titled "Behavior of Coal Ash Particles in Water." And sub to that, "Trace Metal Leaching and Ash Settling," and it does speak a lot about the effluent of the water that is the sluice water that's pumped to a pond, and the quality of the effluent in the pond, in addition to talking about, as I have cited here, what happens or what their conclusions were about leaching of constituents from the effluent in the ash to groundwater.

Q. Okay. And I'm looking -- I was actually looking for what the report, itself, indicated was its scoping document. Scoping -- the scoping for the report. And it's located at the bottom of page 3, top of page 4. If you're following in the joint exhibits, those are DOCX 17 and 18.

A. Are we looking at the -- I'm sorry, are we looking at the EPA 1980 report now?

Q. Yes.

A. And what hard copy page are we looking at?

Q. 3 to 4.

A. 3 to 4 of the abstract or -- Roman numeral III and IV or --

Q. No, Arabic numeral 3 and 4.

A. Okay. So let me get to that. I'm sorry. And what was the joint exhibit number?

Q. 6.

A. (Witness peruses document.)

So the DEC Exhibit 6, I must be in the wrong one. This looks --

Q. Yeah. Mr. Quarles, it should be the Joint Exhibit 6, not the DEC Exhibit 6.

A. (Witness peruses document.)

There we go.

Q. But if you have a different copy of -- your own copy of the 1980 EPA report, we can walk through there.

A. I have it open now in the PDF. So I'm looking for hard copy page 3 and 4?

Q. Yes. And if you're on a PDF, it's probably about page 17 or 18.

A. Okay. I'm on 17 and it begins, first word is "considerations is still an important factor for ash disposal."

Q. Right. So the last paragraph on that page says:

"The scope of this study involves field survey, et cetera."

A. Yes.

Q. And the report addresses six major areas of concern. And those areas of concern relate to -- primarily to effluents, correct?

A. It says:

"This report addresses six major areas of concern in wet ash disposal, namely the characteristics of ashes, which is the solid, and ash pond effluent. Number 2, the effects of ash, solids, and raw water characteristic on the pH. And then" --

Q. pH of ash pond water, correct?

A. That's right. And then methods for pH adjustment, number 3. And then 4, settling characteristic --

Q. Well, and number 3 is methods of pH adjustment of ash pond effluents, correct?

A. That's right, yes.

Q. And then the settling characteristics, and the leaching of minerals, and the relationship of trace metals to pH --

A. Yes.

Q. -- and the concentration of suspended solids.

A. Yes.

Q. And then in the next paragraph it says:

"This report is complimentary to two other studies, one of which is the effects of coal ash leachates on groundwater quality," correct?

A. It -- yup.

Q. And that was one that we discussed with Mr. Hart yesterday. It's Joint Exhibit 5.

Do you recall any of that discussion?

A. I don't.

Q. Okay. You did not refer to the EPA TVA report titled "Effects of Coal Ash Leachate on Groundwater Quality" in your testimony, correct?

A. I don't think so, no. I have not reviewed that document.

Q. Okay. I mean, is there some reason why -- I mean, they are both done by the TVA and the EPA. They're both March of 1980. One of them is titled "Effects of Coal Ash Leachate on Groundwater Quality," which I thought was a focus of your testimony, and you didn't refer to it. But you referred to the other one that deals with effluents.

A. Yeah. So part of the issue is, you know, finding documents through the old NEPIS EPA website and downloading those documents, you know, and you do it by keyword searches, and so sometimes you get a thousand documents that show up. So you try to identify. And I would have -- yeah, I would've loved to have seen this document and reviewed it. If -- particularly if it's written by EPA and TVA, I'm quite familiar with TVA coal ash disposal.

Q. Okay. Mr. Quarles, why don't we move on to the other EPA document that you reference on page 11, which is 1988 report to Congress.

A. Can I close this document?

Q. Yeah. We're done with both 5 and 6, so you can close out of those.

A. Okay. So now we're moving to the report to Congress in '88?

Q. Yes.

A. (Witness peruses document.)

And what -- what is the exhibit name of that?

Q. It is Joint Exhibit 13.

A. Okay.

Q. And at the bottom of page 11, you -- I guess you have three bullets. The first two deal with the 1980 document that we just talked about, and the third bullet deals with the 1988 EPA report to Congress, correct?

A. That's right.

Q. And immediately above the bullets, you state:

"EPA's key conclusions include" --

And then with respect to the 1988 report to Congress, the third bullet is:

"The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause groundwater contamination."

Did I read that correctly?

A. You did.

Q. So, Mr. Quarles, the EPA report to Congress has a whole chapter on conclusions and recommendations; does it not?

A. It does, yeah.

Q. Okay. And we can read that whole chapter, which is Chapter 7, backwards, forwards, and upside down, and we won't find what you call a key conclusion in that chapter, will we?

A. So the key conclusion relative to the likelihood of contamination of groundwater from coal combustion sluicing in unlined basins, which was the context of my testimony.

Q. Well, did you think that the actual conclusions of the EPA report to Congress were not relevant to your testimony?

A. Again, it's the key conclusion related to concerns about leaking impoundments relative to groundwater quality, that is a -- that's an obvious conclusion made by EPA.

Q. It is not a conclusion that it chose to include in Chapter 7 called "Conclusions and recommendations," is it?

A. Okay.

MR. MEHTA: Madam Chair, I think I'm finished with Mr. Quarles for right now.

CHAIR MITCHELL: All right, Mr. Mehta, thank you. Any additional cross examination for this witness?

(No response.)

CHAIR MITCHELL: All right. Redirect for the witness?

REDIRECT EXAMINATION BY MS. CRALLE JONES:

Q. Mr. Quarles, we began talking about Joint Exhibit 6, which I believe was the 1980 EPA report, and you were asked why you focused on that report related to effluent in the context of concern about impacts to groundwater.

Would you explain why those you found were important conclusions from that report?

A. Yes. So let me pull that report, please. The ash transport water -- I will read you from the abstract of that document.

"The chemical characteristics of ash pond effluents are affected by the ash material and the quantity and quality of the water for sluicing." And it says, "TVA ash pond effluents vary from a pH of 3 to 12."

So when we talk about the opportunity of degradation of water, we have to remember that effluent is what is pumped to the surface of the ash pond. And one of the -- one of the factors associated with the leachability of constituents from coal ash is pH. And so, therefore, pH, if it ranges from 3 to 12, according to TVA, what that means is two things. Their surface discharge permit probably has a pH limitation that they are required to meet, and sometimes that requires the addition of chemicals, like ferric chloride, for example, to adjust the pH.

The pH also plays a role in the leachability of the constituents that adhered to the particles of fly ash, for example. Some metals preferentially leach in an acidic environment. Some metals preferentially leach at neutral, near neutral, and some at basic. And then some leach regardless of pH. All right?

So understanding effluent quality to the pond is important, according to this document and according to my experience. All right? So -- and then my experience too is that the quality of the water beneath the standing effluent in the pond, in the pore space of the ash, can vary as well. Can change pH dissolved oxygen, those geochemical changes, which can also affect the leachability of metals.

That's why this document was kind of a good starting point, in terms of understanding how constituents might get to groundwater from an effluent sluicing operation.

Q. And then also earlier we were talking about the studies done at Allen, and you noted that 6 of the 13 monitoring wells were located below the water table and unlikely to provide helpful data for assessment.

Do you know, why would -- why would a
decision be made to place wells so deep?

MR. MEHTA: Objection, Chair Mitchell.
This calls for sheer speculation.

CHAIR MITCHELL: All right.
Ms. Cralle Jones, respond, please.

MS. CRALLE JONES: Okay. I'm just -- if
he -- he may not -- he may read in the documents,
in the A. D. Little report, I'm just not sure
whether or not there was a rationale for that being
there, or if, by putting them so deep, you're not
going to get the data that you need.

CHAIR MITCHELL: All right. I'm going
to overrule the objection, allow the question to
proceed, and we'll give it the weight that it's
due.

THE WITNESS: I'm sorry. Does that mean
that I can answer the question?

CHAIR MITCHELL: It means that your
counsel may proceed to ask -- please ask the
question again, Ms. Cralle Jones, for purposes of
the record.

Q. You noted in the Allen study that 6 of the 13
wells were located below the perched water table.

Are you aware of -- or aware of any reason for placing those wells below where the upper -- below -- below the -- in the deepest aquifer? What would the reason for that be?

A. Well, if your goal is to understand that the -- whether or not an unlined disposal area, or any disposal area, or any pile of waste, if you want to know the effects of the uppermost aquifer on any leakage from those disposal units, good engineering, good hydrogeology, good geology, good common sense practices say that you would want to screen your well in the interval that is most likely to be nearest the waste, and therefore would have the highest concentrations, if the impoundment is leaking. All right?

So if -- and I'll refer you to page 21 of my -- of my testimony as a good exhibit, if you will, for the Commission and other folks to understand what that means. So if you look at those -- that's a cross section, and the ash basin is shown on the right. And this comes from the 1984 internal Duke report. The wells are the vertical rectangles that have the dark triangles in them. The dark triangles are water levels. Okay? Water levels meaning they drilled the well, and after they completed the well, those are the water levels that rose in the well.

You'll see that we have a leachate plume at well 11, and Lake Wylie off to the left. And notice that the triangle in well 13 is nearly the same as the full pool level of Lake Wylie, which is what you would expect in a water table aquifer, because the water table flows into the nearest receiving stream.

So if the -- and the scale of this drawing is on the left, and it looks like every notch is 10 feet. A well screen is typically 10 feet. Sometimes I've seen 5 feet and sometimes 15. They're not shown on here. But the bottom line is, if you drill a well and screen it deeper than the triangles, and what they called the perched water table, then, in all likelihood, they missed the evidence of leakage and perhaps the highest concentrations of constituents that would be indicative of that leakage that's flowing into Lake Wylie.

So it's fundamentally -- I would -- I'm not going to, you know, try to answer why they chose to not sample the purchased water, but I can tell you that a competent hydrogeologist who's trying to determine whether or not a surface impoundment is leaking would not have done that.

CHAIR MITCHELL: All right. We are going to stop at the moment. We will go off the record. We will take a 15-minute break, and we'll go back on at 11:00.

(At this time, a recess was taken from 10:48 a.m. to 11:00 a.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please. We will continue with redirect of Mr. Quarles. Ms. Cralle Jones, you may proceed.

MS. CRALLE JONES: I have no more questions.

CHAIR MITCHELL: All right. Questions from Commissioners, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: All right.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Quarles, can you hear me?

A. Yes, ma'am.

Q. At -- in your testimony, on page 18, starting at the top there, you were answering a question about the Company's conclusion that CCR constituents detected during the groundwater monitoring were naturally occurring, and whether that conclusion was reasonable. And your answer was no. And you go on to say, because it's been shown to be -- or at least you offer one of the reasons, it's to be shown to be incorrect. That in -- that in 2014, the Company concluded that it was the coal ash that was impacting the groundwater.

A. Yes, ma'am.

Q. And that conclusion that the Company made, was that based -- from your understanding, that was -- you were speaking of it emanating from the voluntary monitoring they were doing from the mid-'90s up to, say, 2007 or so?

A. No. That -- that statement came from a 2014 internal corporate slideshow where they concluded our coal ash is impacting groundwater at all locations.

Q. So -- so they made -- this conclusion was made in 2014, that it was naturally occurring?

A. No. 2014, they admitted that the coal ash disposal is impacting groundwater at all locations, which would override any prior determinations that any constituents were related to naturally occurring conditions.

Q. And so the question was about the reasonableness of that conclusion, about the naturally occurring. And you said no, that -- am I interpreting you correctly that no, that conclusion was not reasonable at that time, or just that it has since been shown to be incorrect?

A. Well, without doing a thorough evaluation, you would not know if it is naturally occurring or not, and so you can only do that by installing wells and having a representative background determination of your constituents. That's step number 1. And step number 2 is ultimately sampling the water. And then they made the determination in 2014, and DEQ agreed with that conclusion, that's why they had to excavate their ash. That it was not all related to naturally occurring conditions or concentrations.

Q. So at what point in time had they made the naturally occurring conclusion; do you know?

A. There was a --

Q. That's the basis of the question.

A. Yeah. There was a -- there was a direct -- I might be able to find it. Yeah, here we go. It's in my Exhibit 4. Exhibit 4, and I have a hard copy, but it's the Public Staff Request 36-2. And the timing of this Exhibit 4 is dated January 2018. And at the bottom of page 1 of 2, it says:

"Initial results appeared consistent with naturally occurring conditions. So between the installation of voluntary monitoring wells in 2009, DE Carolinas continued monitoring the wells and submitted semiannual reports."

So what they're saying -- what they said in 2018 was that initial appeared to be naturally occurring. And then if you look at page --

Q. And initial is 2009; is that how you interpret it, or earlier?

A. Yeah. So on page 17 of my testimony, it has a table that shows the voluntary monitoring well installation, which the Company used the term "voluntary," and I'm assuming that that was the USWAG information, and then required monitoring installations. And then you'll see that the detection of a 2L standard generally came within the same year, perhaps a year after the voluntary monitoring. So that's when they would have apparently made that conclusion that it was all naturally occurring.

Q. With the exception there of Cliffside, there's a 1995 --

A. Yeah. And Dan River 1993, yeah.

Q. Well, Dan River 1993, there's a detection in

1993.

A. That's right.

Q. Cliffside 1995 -- there was 1995, 2005, and 2007 --

A. Yes, ma'am. Oh-oh.

CHAIR MITCHELL: It seems that we have lost connection to Commissioner Brown-Bland. Let's give it a few seconds to see if she returns.

(Pause.)

CHAIR MITCHELL: All right. Looks like she's back.

Commissioner Brown-Bland, can you hear us?

COMMISSIONER BROWN-BLAND: Are we back?

CHAIR MITCHELL: Commissioner Brown-Bland, are you there?

COMMISSIONER BROWN-BLAND: Yes, I hear you.

CHAIR MITCHELL: All right. We lost you temporarily.

COMMISSIONER BROWN-BLAND: That's my morning departure. Hopefully that's the last time.

Q. So I was just getting to what's your basis for the answer to the question there, that it was --

that the naturally occurring conclusion was not reasonable at the time that that -- that they came to that conclusion, which appears to be after 2009 is according to what you were reading; is that right?

A. Let me see that again.

(Witness peruses document.)

That's right.

Q. So what was your basis for saying it was not reasonable? Should they have known at that point, or was there a failure to do a certain degree or type of monitoring?

A. So it's hard to imagine how we've gone from -- let me back up. So I've looked at coal combustion waste disposal sites across the country, a lot of them, and I've seen arguments for what is background and what is naturally occurring, and it's very, very true that metals, arsenic, boron, they do naturally occur. All right? But you also have indicator parameters like sulfate that are directly associated with coal combustion waste. It naturally occurs too, but it's very prominent in coal combustion waste.

So it was -- as a scientist, it was hard to imagine how the Company could have claimed in 2009 that every disposal facility and all the contamination, the constituents that are in the well is all naturally occurring. That's just not reasonable given the size and the way that these materials were disposed of.

So it's not surprising that they changed their mind and came to the conclusion that it was related to coal combustion waste.

Q. And so your answer was based on more than -- I mean, is it correct that your answer was based on more than just the fact that ultimately they got it wrong, but even at the time that they came to that conclusion, it was an unreasonable conclusion?

A. Yeah. So my statement was really is ultimately it was -- they admitted in 2014. I haven't looked at each of the individual facilities where they perhaps tried to make the argument that they were naturally occurring or not to know how valid or not that was back in 2009, if they made such a -- you know, a public determination of that.

Q. But is that a basis for the unreasonableness that -- I guess that's what I'm trying to get at. Is it unreasonable in your mind just because ultimately it was proven and shown to be wrong, or was it unreasonable because of some action, or inaction, or misunderstanding, or something like that on their part, on the Company's part?

A. I think it's unreasonable -- it's unreasonable to make a blanket determination that everything was naturally occurring, in my experience. Because the signature of coal combustion waste constituents from a leaky disposal unit is very clear.

Q. And did the Company, at that point in time when they became aware of the detection of these CCR constituents, did they have a specific response that you learned about as a result of that, you know, at that time when they first learned about the constituents?

A. My research didn't look at the Company's responses to those post 2009, per se.

Q. All right. And on page 19 there, you're answering the question:

"Was the Company's reliance on the Little 1985 report for a decision not to monitor groundwater at Allen and other disposal sites; was that reasonable?"

And you answered no, and you give some reasons. And what I'm looking at is lines 8 through 10. And there you address the soil attenuation estimates and say that they did not accurately predict.

What's the significance of that?

A. So what they tried to do is they tried to -- one of the purposes of the '84 study, the internal document, and then the A. D. Little too, they looked at -- leaching tests are laboratory tests where you can collect samples of CCR, and then you can -- they referred to the EPA leaching method and the ASTM leaching method. What those methods try to do is to predict, at those laboratory conditions, what the concentrations of constituents are going to be that come out of or come away from the solid and get into water, right?

Those -- and then -- and then you make calculations based upon the clay content of the soil and the ability of the clay to capture or attenuate the constituents. And it's true, soil attenuation is one of the eight factors that EPRI talked about in the early 1980s as an important consideration. But the report did not accurately -- they didn't accurately predict whether or not it would attenuate and whether or not -- and how long that attenuation would last. So they couldn't rely on that portion of the investigation.

Q. Now, is that a flaw of the -- of the study, or was that a flaw of some of Duke's work? Whose -- whose estimate, I guess?

A. It was -- I'm not sure what A. D. Little -- if they relied upon the study that Duke did for their 1984 study or not. But the bottom line was that the laboratory test, and then the calculations that they used to predict that the constituents would be attenuated by the clay soils did not come true. Therefore, they were not reliable predictors of the soil attenuation capacity.

Q. At the time that they made that -- you know, those attenuation studies, should they have been able to do so, you know, in a more reliable manner, a better test?

A. Well, so --

Q. At that time.

A. So what -- what's really amazing is they talk about the clay content of the soil in the reports, and what's really -- when you dig in the A. D. Little report, it also talks about the predominant soil at Allen is more of a sandy soil, right. So if they assumed in their attenuation capacity calculations that the soil was clayey, and then instead it's sandy, then that would have been a mistake by whomever made that calculation.

Q. All right. And then I'm on page 21, and this is testimony regarding the 1984 internal investigation of groundwater at Allen. Lines 10 through 16 is speaking to the issue with monitoring well construction and location or placement of the monitoring wells -- this is what you were addressing a moment ago -- and the role that played in not adding more monitoring wells, I assume, or continuing to monitor.

And you explained using that diagram why it would have been maybe better other placements, but at the time back in 1984, or even assuming that they started it in '83 maybe, I don't know, but at that time, would the Company have known or should have known a better way to capture any leakage -- as you called it, capture at the perch -- at the perch level?

A. Well, so --

Q. Was that part of the science at that time that they should have known or placed it differently, you would have thought?

A. So EPA and EPRI talk about the two most important factors of a groundwater monitoring system are the location and the depth of the well. All right.

The Company installed wells along the perimeter of the ash basin, in this case between the ash basin and Lake Wylie, and that was a good move. But the mistake that seems to have been made is that they screened the wells deeper and missed the perched water zone that would be more indicative of leakage associated with the impoundment.

Q. And when you're monitoring groundwater, doing groundwater monitoring, it would have been appropriate still to check at the perch level?

A. It would, yeah. So what commonly happens is that you start your investigation at the uppermost portion of the uppermost aquifer. And what you're also able to do, and what we found, kind of if you will, the evolution of, you know, groundwater monitoring is that we've learned because of the constant head of standing water -- and Allen, for example, had 100 feet of saturated ash in 2015. So that constant head has a vertical -- it pushes groundwater deeper over time, right.

So a common investigation is to start with a shallow well and understand whether or not you have a vertical gradient that pushes it further into the deeper portion of the aquifer or if the preferential flow is horizontal.

Q. About what you described now, it would not have been known to the engineers or the people who were performing this investigation back at the time that they were doing the investigation?

A. They -- they would have known that, and EPRI talks about that, is that seepage is inevitable, and it's under a constant pressure head. And so, therefore, they should have understood the importance of monitoring the uppermost portion of the uppermost aquifer nearest the bottom of the waste, and whether or not there was any contamination that could be pushed deeper into the aquifer, or if the preferential flow was horizontal into Lake Wylie. The fundamentals of a groundwater monitoring system have been consistent in that knowledge certainly since the early '80s.

Q. All right. And on page 23, you talk about gravel and sand in the impoundments. And I'm in the area of line 11 through 19. And there you talk about gravel and sand naturally occurring. Or no, that's my question to you.

Are you saying that the gravel and sand in those impoundments were naturally occurring in there, or are you suggesting that the Company built the impoundments with the sand and gravel as part of the construction?

A. So the sand and gravel is the soil type that is in the area site-wide, according to the comprehensive site assessment in 2015, is the common most popular populous soil type at the Allen plant. All right. So with that in mind, gravel and sand are much less effective in attenuating or mitigating contaminants that might leak from an impoundment and get into the groundwater.

Q. And so it would have been natural that you would build the impoundment using the soil that was there? And during the time, they would not have necessarily brought in a better attenuator; is that correct?

A. Well, so let's think about this. The way that they built the impoundment was they took an existing stream valley and built a dam across the valley, and then started pumping water into the impoundment. So there was no construction or placement of soil as a line or any other sort of barrier or separator between the uppermost aquifer and the bottom of the waste.

And what is possible, to build the dike, the dirt has to come from somewhere or the material has to come from somewhere. And most times that material is excavated from onsite and moved to build the dam. In addition, it's quite common that ash was used to build the dike. So if -- if the material was removed from the stream valley to build the dike, then, in the case of Allen, there is bedrock that is relatively shallow there, and they would have removed a buffer that would be associated with any soil that would be above the bedrock.

And why that's important is that -- is that the groundwater velocity -- the groundwater seeps through the material that makes up the aquifer, and the material is soil and bedrock. And the groundwater flow velocity in bedrock is much faster than the groundwater flow velocity in soil at Allen.

Q. Okay.

A. But the sand and the gravel was consistent and very common across the Allen site before they built the impoundment.

Q. All right. Thank you. And then on, I think, page 24 you -- moves on to discuss the River Bend site a little bit, and we're say -- you're saying here that the Company had incorrectly assumed that there was enough similarity between the Allen and the River Bend sites to warrant not installing monitoring wells, and to not recognize that the differing or changing conditions that occur over time.

So in your opinion, the Company got that wrong. Could it have been reasonably known, at that time of their conclusion, that there was a flaw in this assumption or in the way that -- or in their work that led to the assumption?

A. So EPRI was -- EPRI was very clear about the need to do a site-specific analysis of each of these sites. Allen and River Bend were located 12 miles apart. So it is -- it is unreasonable to assume that the exact conditions and attenuation factors, if you will, exist at Allen and also at River Bend. And when you look at the River Bend report, then, in fact, they brought out some information on the borings and the soil type that was at River Bend. The problem with that is none of the borings were underneath where they put the ash. They're up on top of the hill. What's important is the soil type beneath the ash. All right. So they didn't do an evaluation of that.

They didn't collect basic information like the soil hydraulic conductivity, how fast water flows through the soil, the soil type. So there were lots of flaws in that use of Allen data to support no monitoring at River Bend.

Q. So, Mr. Quarles, so we -- as you sit here today, we know that, and we know that that's what we should be doing. And I guess just to be clear, should we have known it and should the Company have known it back when they were making these assumptions and decisions? Is the state of knowledge similar enough to what it is today that they should have known that?

A. Yes. So it is very clear, EPRI determined that leakage from an unlined surface impoundment is inevitable, and it is under a constant head of pressure. And the only way to have convincing proof that you are not contaminating an underground source of drinking water is to install wells, right? And wells are not very expensive. Like, a 20-foot well may cost, in today's dollars, $2,000. You know, the leaching test that they may have done, who knows how many thousands of dollars they spent on a test which ultimately relied on assumptions for a site 12 miles away without collecting any site-specific data that could have been collected at River Bend.

Q. And so if there was a decision made that they had done enough work over at Allen and it was close enough and good enough for soil similarities, your opinion is it wasn't good enough, and it was known not to be good enough at that time?

A. So again, it's inevitable. Leakage is inevitable. It's a constant head of pressure. And the convincing proof to know whether or not you're impacting groundwater is to install a well. And it's up to the generator to have convincing proof to determine whether or not they're in compliance with the 2L standard.

Q. All right. Thank you, Mr. Quarles.

A. You're welcome.

COMMISSIONER BROWN-BLAND: That's all I have right now.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions at this time.

CHAIR MITCHELL: Okay. Commissioner Clodfelter?

COMMISSIONER CLODFELTER: I have no questions for Mr. Quarles. Thank you.

CHAIR MITCHELL: All right.

Commissioner Duffley?

COMMISSIONER DUFFLEY: Yes. I just have one follow-up question.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Commissioner Brown -- I just want to understand what I heard you say. So Commissioner Brown-Bland asked you about the placement of wells, and I thought I heard you say, you know, the hydraulic head would push potential contaminants deeper into the aquifer. And so I just want to make sure I understand your testimony.

So you said that they put wells, stream wells deep in the aquifer, but your testimony is that they should have also put in shallower well; is that an accurate description of what I heard?

A. Yes, sort of. So if you want to know if a disposal unit is leaking, you put wells in the uppermost portion of the uppermost aquifer; that is step number 1. And what that does is tells you whether or not you've got a good indication of leakage from the disposal unit. What can also happen is that, with the constant head and the constant pressure, that there can be a downward push, and you won't know that unless and until you've installed wells in the upper portion and

in the deeper portion.
Q. Okay. Thank you.
COMMISSIONER DUFFLEY: I don't have anything further.
CHAIR MITCHELL: All right. Commissioner Hughes?
COMMISSIONER HUGHES: No questions. Thank you.
CHAIR MITCHELL: Commissioner McKissick?
COMMISSIONER McKISSICK: No questions at this time.
CHAIR MITCHELL: All right. Questions on Commissioners' questions? Any party have questions on Commissioners' questions?
MS. LUHR: I have no questions.
MS. TOWNSEND: No questions.
MR. MEHTA: No questions from Duke.
CHAIR MITCHELL: All right. Ms. Cralle Jones, any questions on Commissioners' questions? All right. Ms. Cralle Jones, I believe you're muted, but I believe you've said no questions. Okay.
All right. Mr. Quarles, you may step down at this time. Ms. Cralle Jones, I'll

entertain motion from you.

MS. CRALLE JONES: At this time, we now move that Sierra Club Quarles Exhibits 1 through 4 be admitted into the record.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Ms. Cralle Jones, it will be allowed.

(Sierra Club Quarles Exhibits 1 through 4, were admitted into evidence.)

MS. CRALLE JONES: And would request that the witness be excused for the DEC portion of this hearing.

MR. MEHTA: Chair Mitchell, I would also move -- this is Kiran Mehta, would also move the introduction into evidence of DEC Quarles Cross Examination Exhibit Number 1.

CHAIR MITCHELL: All right. Mr. Mehta, hearing no objection to your motion, it is allowed, and the witness may be excused.

(DEC Quarles Cross Examination Exhibit Number 1, was admitted into evidence.)

CHAIR MITCHELL: All right. Thank you very much, Mr. Quarles, for your testimony today.

THE WITNESS: You're welcome.

CHAIR MITCHELL: All right. Sierra Club, we are still with you. You may call your next witness.

MS. LEE: Thank you, Chair Mitchell. Sierra Club calls Ms. Rachel Wilson.

CHAIR MITCHELL: Good morning, Ms. Wilson. Let's raise your right hand, please, ma'am.

Whereupon,

RACHEL S. WILSON,

having first been duly affirmed, was examined and testified as follows:

CHAIR MITCHELL: All right. Ms. Lee, you may proceed.

MS. LEE: Thank you.

DIRECT EXAMINATION BY MS. LEE:

Q. Good morning, Rachel. Could you please state your full name and business address for the record?

A. My name is Rachel Wilson, and my address is Synapse Energy Economics, 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

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

A. I'm a principal associate at Synapse Energy

Economics.

Q. On February 18, 2020, did you cause to be prefiled in this docket, direct testimony consisting of 23 pages and four exhibits, some portions of which contain information designated confidential by the Company?

A. Yes.

Q. And on February 25, 2020, did you cause to be prefiled in this docket, a corrected version of your direct testimony consisting of 23 pages, some portions of which contain information designated confidential by the Company?

A. Yes, I did.

Q. Could you describe the correction that was reflected in the February 25th testimony?

A. Sure. When I was gathering my work papers in response to a data request from the Company, I noticed that certain spreadsheets underlying that analysis reflected nominal dollars instead of the 2019 dollars that I designated in my testimony. So I made the change to 2019 dollars, and that affected a small number of values in Tables 4 and 5, which presented historical net energy value. However, this change did not affect any of my overall conclusions about the economics of the Company's coal-fired units.

Q. Thank you. And do you have any other changes, corrections to your prefiled direct testimony?

A. No, I don't.

Q. Okay. And if I asked you the same questions again here today, would your answers be the same?

A. Yes.

Q. Okay. And, Ms. Wilson, did you prepare a summary of your direct testimony?

A. I did.

Q. Okay.

MS. LEE: Chair Mitchell, we ask that Ms. Wilson's prefiled corrected direct testimony consisting of 23 pages, some portions of which contain information designated confidential by the Company, and her summary be moved into the record as if given orally from the stand. And that prefiled Sierra Club Wilson Exhibits 1 and 4 and confidential Sierra Club Wilson Exhibits 2 and 3 be marked for identification as premarked.

CHAIR MITCHELL: All right. Ms. Wilson's prefiled testimony as corrected will be copied into the record as if given orally from the stand, as will the testimony summary that has been provided of Ms. Wilson's testimony. And the exhibits to Ms. Wilson's prefiled testimony will be marked as they were -- marked for identification as they were when prefiled.

MS. LEE: Thank you, Chair.

(Sierra Club Wilson Exhibits 1 and 4, and Confidential Sierra Club Wilson Exhibits 2 and 3, were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony as corrected of Rachel S. Wilson and testimony summary were copied into the record as if given orally from the stand.)

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, business address, and position.

A My name is Rachel Wilson and I am a Principal Associate with Synapse Energy Economics, Incorporated ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in electricity industry regulation, planning, and analysis. Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, developers, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct analysis and write testimony and publications that focus on a variety of issues relating to electric utilities, including integrated resource planning, resource adequacy, electric system dispatch, environmental regulations and compliance strategies, and power plant economics.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the Strategist, PROMOD IV, PROSYM/Market Analytics, PLEXOS, EnCompass, and PCI Gentrader models, and I have reviewed input and output data for several other industry models.

Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an economic and business consulting firm, where I provided litigation support in the form of research and quantitative analyses on a variety of issues relating to the electric industry.

I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in Environment, Economics, and Politics from Claremont McKenna College in Claremont, California.

A copy of my current resume is attached as Exhibit RW-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the North Carolina Utilities Commission?

A Yes. I testified before this Commission in Docket No. EMP-105, Sub 0.

Q What is the purpose of your testimony in this proceeding?

A The purpose of my testimony is to evaluate the economics of the coal-fired units owned by Duke Energy Carolinas (DEC or the Company) and assess the prudence of continuing to invest in and operate these units, which include Cliffside Units 5 and 6, Belews Creek Units 1 and 2, Allen Units 1-5, and Marshall Units 1-4.

Q Please identify the documents and filings on which you base your opinions.

A My findings rely primarily upon the testimony, exhibits, and discovery responses of DEC and its witnesses. I also rely to a limited extent on certain industry publications.

In addition to my resume, exhibits to this testimony include:

Confidential Exhibit RW-2: [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Confidential Exhibit RW-3: [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Exhibit RW-4: Georgia Public Service Commission. 2019. Docket No. 42310. Order Adopting Stipulation as Amended

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your primary conclusions.

A My primary findings indicate that all DEC's coal units operated uneconomically for at least the three years from 2016 through 2018. I estimate that each of the coal units had negative net value of between [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] from 2016 to 2018. Despite these net losses, DEC continues to determine unit retirement dates for its coal fleet based solely on depreciation studies.

My analysis shows that each of DEC's coal units will continue to operate uneconomically in the future. DEC has not provided any economic assessments of the continued operation of its coal-fired units, even as low gas prices and declining costs for renewables have disadvantaged many coal units across the country. Thus, the Company has not demonstrated that continuing to invest in its coal fired units is a prudent decision and provides value to ratepayers.

Q Please summarize your primary recommendations.

A Based on my findings, I offer the following recommendations:

1. I recommend that the Commission disallow past spending on capital projects incurred between the 2017 rate case and this rate case, given that the data show that all of DEC's coal units had negative net value in 2016 and 2017, and nine of DEC's 13 coal units had net negative value in 2018. Capital spending during this time period should be disallowed until DEC provides evidence of an analysis demonstrating the value of the investment done at the time the investment decision was made.
2. I recommend that DEC consider operating its units seasonally and only during months of peak demand to minimize losses to ratepayers.
3. I recommend that the Commission place a cap on future capital expenditures intended to prolong the lives of the DEC coal units as generating assets, and require the utilities to come to the Commission for approval of any

expenditure that exceeds that cap before the expenditure can be recovered from ratepayers.

III. DEC'S COAL UNIT PLANS AND PROPOSALS

Q Which DEC generating units are the focus of this testimony?

A This testimony focuses on the economics of DEC's 13 coal units for which the utility is seeking cost recovery in this case. These include Cliffside Units 5 and 6, Belews Creek Units 1 and 2, Allen Units 1-5, and Marshall Units 1-4.

Q What are DEC's plans regarding the future operation of these units?

A Exhibit 1 of the Direct Testimony of John J. Spanos suggests a "probable retirement year" for each of DEC's coal units. According to this document, the probable retirement years are: 2024 for Allen Units 1-5; 2026 for Cliffside Unit 5; 2034 for Marshall Units 1-4; 2037 for Belews Creek Units 1-2; and 2048 for Cliffside 6. These retirement dates accelerate the retirements of Allen Units 4 and 5, Cliffside Unit 5, and Belews Creek Units 1 and 2 from those in DEC's 2019 Integrated Resource Plan (IRP).[1]

Q What is the basis for DEC's assumed coal unit retirement dates?

A DEC bases its retirement dates on the most recent depreciation study approved by the Commission.[2] In the 2019 IRP, the retirement dates were based on the depreciation study approved in the 2017 rate case. Spanos Exhibit 1 is the most recent depreciation study of which DEC is seeking approval in this docket, and the retirement dates listed above come from that study. The depreciation in that study refers generally to the loss of service value that result from "wear and tear, decay, action of the elements, obsolescence, changes in the art, changes in demand and the requirements of public authorities."[3] The depreciable life span estimates for DEC's coal units specifically considered the following: life spans of

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[1] Duke Energy Carolinas. *2019 Integrated Resource Plan*. Page 89.

[2] Duke Energy Carolinas. *2019 Integrated Resource Plan*. Page 89.

[3] Direct Testimony of John J. Spanos. Page 3, lines 9-14.

similar generating units, unit age, general operating characteristics, major refurbishments, and discussions with management personnel regarding the long-term outlook for the units.[4]

Q Did DEC provide any economic analyses of alternative retirement dates in its 2019 IRP or in this rate case?

A No. DEC has not provided any economic analyses of alternative retirement dates for its coal units. DEC was ordered to do such an analysis as part of its 2020 IRP,[5] however, which is expected in September 2020.

Q What is the implication of this lack of analysis?

A The implication of this lack of analysis is that DEC has assumed that it is cost-effective for ratepayers if the utility operates its coal units based solely on their depreciable lives rather than performing an economic assessment. DEC has therefore provided no justification for continuing to invest in its coal units, and thus no basis for asking its customers to pay for capital expenditures associated with continued operation.

Q Have recent electricity market trends affected the economics of coal units in the United States?

A Recent market trends have had a negative impact on the general economics of coal units across the country and led to a sizable number of retirements. According to the U.S. Energy Information Administration (EIA), more than 65,000 MW of coal capacity retired between 2007 and 2018.[6] Coal retirements in 2018 alone totaled 12,900 MW.[7] A range of factors have contributed to these retirements, including sustained low gas prices and increased competition from

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[4] Spanos Exhibit 1. Page 40.

[5] North Carolina Utilities Commission. August 27, 2019. *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*.

[6] U.S. EIA. 2018. *Today in energy: U.S. coal consumption in 2018 expected to be the lowest in 39 years*. Available at: https://www.eia.gov/todayinenergy/detail.php?id=37817.

[7] U.S. EIA. 2019. *Today in energy: More than 60% of electric generating capacity installed in 2018 was fueled by natural gas*. Available at: https://www.eia.gov/todayinenergy/detail.php?id=38632.

renewables, which can be expected to persist in the future. Competition from gas and renewables has led to decreases in capacity factors at the coal units that have continued to operate.[8]

Q Have other utilities responded to these changes in the electric sector by conducting retirement assessments of their coal units?

A Yes. Economic assessments of existing coal units have become an increasingly common component of utility resource planning. In its 2018 IRP, Northern Indiana Public Service Company (NIPSCO) examined alternative retirement dates for its five existing coal units, concluding that customers would save more than $4 billion by retiring those units in 2023 rather than operating them until 2030.[9] PacifiCorp's 2019 IRP includes a unit-by-unit retirement analysis of alternative retirement dates, years before the end of the units' depreciable lives, for each of its 22 coal units across its six-state service territory.[10] Georgia Power's 2019 IRP also included a retirement analysis for each of its existing coal units.[11]

Q What are the important characteristics of a rigorous coal unit retirement analysis?

A A rigorous analysis would include all costs and benefits associated with near-term and mid-term retirement dates. The continued operation of each coal unit would be compared to an optimized replacement resource portfolio, rather than a single replacement resource, that can provide all of the services that would otherwise be provided by the retiring unit. The cost of replacement resources should be informed by recent all-source requests for proposals (RFPs).

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[8] U.S. EIA. 2018. *Today in energy: U.S. coal consumption in 2018 expected to be the lowest in 39 years*. Available at:
https://www.eia.gov/todayinenergy/detail.php?id=37817.

[9] Northern Indiana Public Service Company LLC. 2018. *Integrated Resource Plan*. Available at: https://www nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15.

[10] Utility Dive. 2019. *Pacificorp sees 2 GW coal retirement, $599M savings by 2040 in latest planning scenarios.* Available at: https://www.utilitydive.com/news/pacifcorp-sees-2-gw-coal-retirements-599m-savings-by-2040-in-latest-plann/562670/.

[11] Georgia Power. 2019. *Technical Appendix Volume 2: Unit Retirement Study to 2019 Integrated Resource Plan.* Georgia Public Service Commission Docket No. 42310.

IV. COAL-RELATED COSTS FOR WHICH DEC IS SEEKING RECOVERY

Q What types of coal unit expenses is DEC seeking to recover through this case?

A DEC is seeking to recover three types of expenses associated with its coal-fired units in this case: operations and maintenance (O&M) expenses, ongoing capital expenditures, and previously incurred capital expenditures associated with unit maintenance and environmental projects.

A What is the test year upon which DEC's rate case application is based?

The test period is January 1, 2018 through December 31, 2018.

Q What levels of O&M expense did DEC incur at its coal units in 2018?

A The plant-specific O&M expenses incurred by DEC in 2018 are listed in Table 1. DEC's total 2018 O&M expense at its four coal plants totals $192.8 million.

Table 1. DEC coal plant O&M expense, 2018

Cost Description	Allen	Belews Creek	Cliffside	Marshall
500 - Oper. Supv. and Engr Exp	$ 2,509,861	$ 3,864,728	$ 2,808,785	$ 4,440,801
502 - Steam Exp	$ 5,259,905	$ 16,818,140	$ 15,502,867	$ 15,631,121
505 - Electric Exp	$ 1,640,748	$ 1,401,414	$ 1,960,610	$ 2,335,330
506 - Misc Steam Power Exp	$ 2,806,754	$ 5,320,866	$ 4,096,446	$ 5,236,860
509 - Allowances	$ 107	$ 1,819	$ 581	$ 1,693
Total Operations	**$ 12,217,375**	**$ 27,406,967**	**$ 24,369,289**	**$ 27,645,805**
510 - Maintenance Supv and Engr	$ 2,128,603	$ 4,674,208	$ 2,565,924	$ 3,839,799
511 - Maintenance of Structures	$ 2,901,369	$ 12,067,660	$ 4,035,090	$ 5,164,734
512 - Maintenance of Boiler	$ 3,434,025	$ 13,785,625	$ 10,981,066	$ 12,355,167
513 - Maintenance of Electric Plant	$ 1,258,030	$ 7,305,692	$ 3,411,695	$ 6,067,265
514 - Maintenance of Misc Steam Plant	$ 487,487	$ 2,348,327	$ 670,184	$ 1,650,557
Total Maintenance	**$ 10,209,514**	**$ 40,181,512**	**$ 21,663,959**	**$ 29,077,522**
Total Operation & Maintenance	**$ 22,426,889**	**$ 67,588,479**	**$ 46,033,248**	**$ 56,723,327**

Source: Sierra Club DR 2-1 Attachment 1.xlsx.

Q What levels of capital expense did DEC incur at its coal units in 2018?

A The plant-specific capital expenses incurred by DEC in 2018 are listed in Table 2. DEC's total 2018 capital expense at its four coal plants totals $509.4 million. This includes expenditures classified by the Company as associated with ash and wastewater compliance under the Coal Combustion Residuals (CCR) rule and the Effluent Limitation Guidelines (ELG) as well as capital expenditures associated with maintenance and investment.[12]

Table 2. DEC coal plant capital expense, 2018

Plant	CCR/ELG	Non-Environmental	Total CapEx
Allen	$70,376,644	$22,182,553	$92,559,197
Belews Creek	$52,831,663	$91,945,624	$144,777,287
Cliffside	$14,646,379	$100,399,363	$115,045,743
Marshall	$83,469,539	$73,513,019	$156,982,558
Total	$221,324,225	$288,040,559	$509,364,784

Source: Sierra Club 2-1c DEC Capital – Supplemental.xls.

Q What levels of capital expense is DEC planning to incur at its coal units in future projections?

A The plant-specific capital expenses planned by DEC for the 10-year period between 2019 and 2028 are listed in Confidential Table 3. The combined environmental and non-environmental capital expenditures total almost [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in 2019 alone.

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[12] Synapse sorted Duke's capital expenditures into the CCR/ELG and non-environmental categories.

Confidential Table 3. [redacted]

Year	Environmental				Non-Environmental				Total
	Allen	Belews Creek	Cliffside	Marshall	Allen	Belews Creek	Cliffside	Marshall	
2019	[redacted]								
2020									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									

Source: CONFIDENTIAL_DEC Sierra Club DR 2-13.xlsx, No CO2 Constraints.

V. HISTORICAL ECONOMIC STATUS OF DEC COAL UNITS

Q Did you assess the recent performance of DEC's coal units?

A Yes. Using data provided by DEC, I evaluated the net value of each of DEC's coal units between 2016 and 2018.

Q Please summarize your findings regarding the recent economic performance of DEC's coal units.

A Confidential Table 4 summarizes the results of my analysis. I find that for each of DEC's coal units, the costs to maintain and operate the unit exceeded the value provided by the unit by a total of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] over the three-year period. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL][13]

[13] [BEGIN CONFIDENTIAL [redacted] [END CONFIDENTIAL]

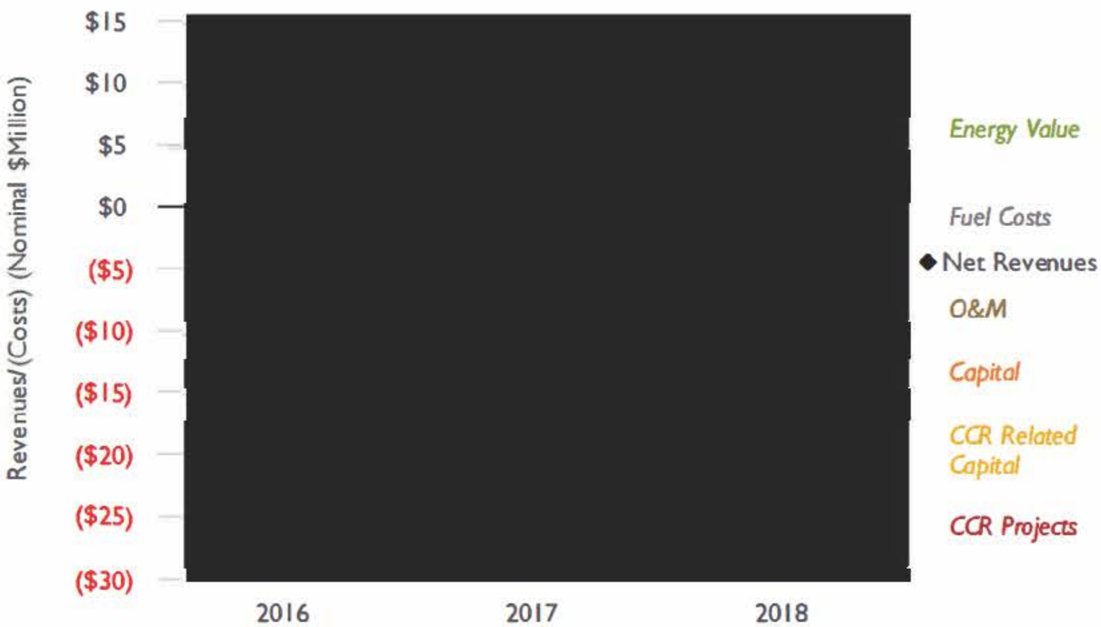
Confidential Table 4. [redacted]

Unit	2016	2017	2018	Total
Allen 1	[redacted]			
Allen 2				
Allen 3				
Allen 4				
Allen 5				
Cliffside 5				
Cliffside 6				
Marshall 1				
Marshall 2				
Marshall 3				
Marshall 4				
Belews Creek 1				
Belews Creek 2				

Sources: DEC discovery responses; Synapse tabulation.

Confidential Figure 1 shows the energy value and cost streams for Allen 1, as well as the unit's net revenues between 2016 and 2018. Individual results for the other 12 DEC units are shown in Confidential Exhibit RW-2.

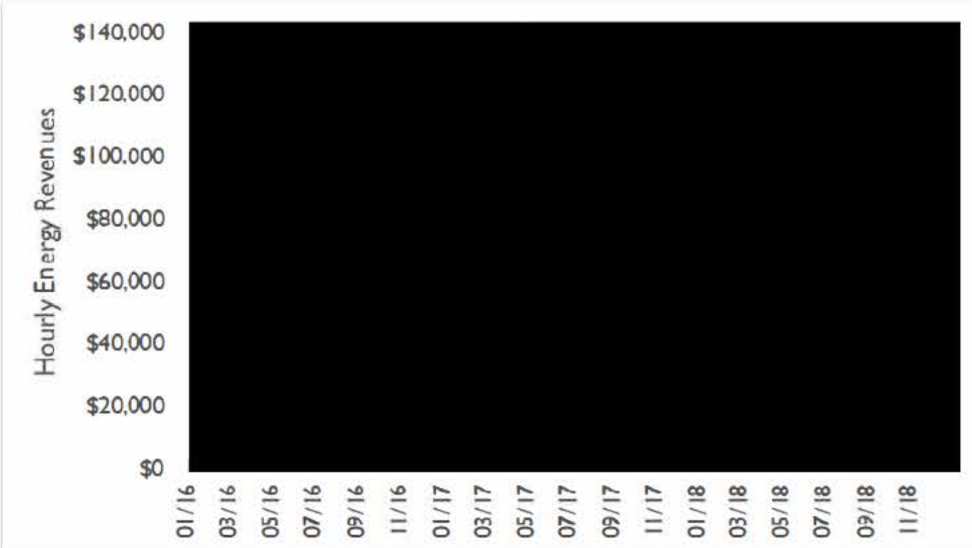
Confidential Figure 1. [redacted]



Q Why do the units have higher energy values in 2018 despite producing less energy on average compared to 2016 and 2017?

A This is mainly attributed to the cold snap in early 2018, as shown in Confidential Figure 2, below. The hourly lambda for the peak times in January 2018 increased to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. Therefore, the units earned a disproportionate amount of value compared to previous months due to this cold snap.

Confidential Figure 2. [redacted]



Q Describe how you arrived at the values in Confidential Table 4.

A The values presented are based on data related to each unit's energy value, fuel costs, O&M costs, environmental costs, capital costs, and ash management costs.

DEC provided historical hourly generation for each of the units.[14] To calculate each unit's energy value, each unit's converted hourly net generation was

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[14] DEC Response to Sierra Club DR 2-10, attachments "CONFIDENTIAL 2019 DEC NC Sierra Club 2-10 – DEC Coal HourlyProdCost2018-2019.xls" and CONFIDENTIAL 2019 DEC NC SC 2-10e- Coal HourlyProdCost 2016-2017-Supplemental.xls".

Although DEC did not specify if these hourly generation values were gross or net, a comparison to the monthly net generation values that were provided in 2-10D indicate that the hourly values were gross. Despite the fact that we had explicitly requested hourly net generation via discovery, DEC provided monthly net generation values to SC 2-10D. In DEC's response to SC 2-10E, the Company provided hourly production costs and hourly generation in MWh. Because the monthly net generation values provided in 2-10D were always smaller than the hourly generation values aggregated to the monthly level provided in 2-10E, it is valid to assume the hourly values are gross. For example, the net generation for Allen 1 in May 2016 was reported by DEC in 2-10D to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] MWh. However, when the hourly MWh values for Allen 1 in May 2016 from 2-10E are summed, the result is zero. Because negative hourly generation values never appear in 2-10E, the values must be gross.

To convert the hourly gross generation to hourly net generation, the hourly gross values were multiplied by a net-to-gross ratio. This ratio was calculated by dividing the provided monthly net generation by the aggregated hourly gross generation for each unit, month, and year.

multiplied by the relevant hourly DEC system lambda[15] as provided in discovery.[16]

DEC provided the total fuel cost burned at the plant-level, and these costs were allocated based on annual generation levels to get unit-level fuel costs.[17]

DEC also provided O&M costs at the plant-level. Although it is standard to show fixed O&M costs separately from non-fuel variable O&M costs, DEC stated in discovery that "the Company does not identify historical costs as either fixed or variable."[18] For this reason, the O&M costs are shown as one category and the plant-level costs are divided into unit-level costs using annual generation levels.

DEC provided plant-level capital costs. For the years 2016 and 2017, these capital costs were classified by category.[19] These categories included "Environmental", "Investment", and "Maint-Maint". The capital cost workbook also had a column to indicate if the cost was related to Coal Combustion Products. The capital costs provided for 2018 were not labeled by category, nor was there a column to indicate if the cost was related to Coal Combustion Products.[20] It was therefore assumed that a capital expenditure was associated with Coal Combustion Products if it had the text "CCP" or "Bottom Ash Conversion" in the project description. Because all capital costs were provided at the plant-level, they were allocated to individual units based on nameplate capacity.

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[15] The term "system lambda" refers to the marginal cost of electricity in a system and, in an electricity market, is the locational marginal price of energy in a given hour.

[16] DEC Response to Sierra Club DR 2-10, attachment "SCDR_2-10a_DECSystemLambda.xls".

[17] DEC Response to Sierra Club DR 2-9, attachment "CONFIDENTIAL DEC Sierra DR 2-9i_supplemental.xls".

[18] DEC Response to Sierra Club DR 2-1.

[19] DEC Response to Sierra Club DR 2-9, attachment "2019 DEC NC SC 2-9 j,k Capex DEC 2016-2017-Supplemental.xls".

[20] DEC Response to Sierra Club DR 2-1, attachment "2019 DEC NC Sierra Club 2-1 c DEC Capital – Supplemental.xls".

Q Did you evaluate the economics of the plants without the historical capital expenditures?

A Yes. The results of the economic analysis that exclude historical capital expenditures are shown in Confidential Table 5. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. The remaining units have a [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. Once again, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Confidential Table 5. [redacted]

Unit	2016	2017	2018	Total
Allen 1	[redacted]			
Allen 2				
Allen 3				
Allen 4				
Allen 5				
Cliffside 5				
Cliffside 6				
Marshall 1				
Marshall 2				
Marshall 3				
Marshall 4				
Belews Creek 1				
Belews Creek 2				

Q What are your recommendations to the Commission with regard to any request for recovery of past spending on capital projects at DEC's coal units?

A I recommend that the Commission disallow past spending on capital projects incurred between the 2017 rate case and this rate case, given that the data in Table 4 show that all of DEC's units had negative net value in 2016 and 2017, and eleven of DEC's thirteen units had net negative value in 2018. DEC made capital

Q What are your recommendations to the Commission with regard to any request for recovery of past spending on capital projects at DEC's coal units?

A I recommend that the Commission disallow past spending on capital projects incurred between the 2017 rate case and this rate case, given that the data show that all of DEC's units had negative net value in 2016 and 2017, and nine of DEC's thirteen units had net negative value in 2018. DEC made capital investments in these coal-fired units either without evaluating the economics of continuing to operate the units, or despite the fact that the units had negative value to DEC ratepayers. Capital spending during this time period should be disallowed until DEC provides evidence of an analysis demonstrating the value of the investment done at the time the investment decision was made.

Q Do you have any recommendations with respect to the operation of DEC's coal units?

A The data indicate that DEC's coal units only have positive net value in years with extreme weather. DEC should thus consider operating its units seasonally and only during months of peak demand to minimize losses to ratepayers until their retirement dates.

VI. FORWARD-LOOKING ECONOMIC STATUS OF DEC COAL UNITS

Q Did you also evaluate the forward-looking economic performance of DEC's coal units?

A Yes. I analyzed the projected energy value of DEC's coal units in each year from 2019 to 2040 using data provided by the Company.

Q Please summarize the results of that forward-looking economic analysis.

A Based on DEC's projections, I find that the Company's coal units are likely to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. Confidential Table 6 indicates that [BEGIN CONFIDENTIAL] [redacted]

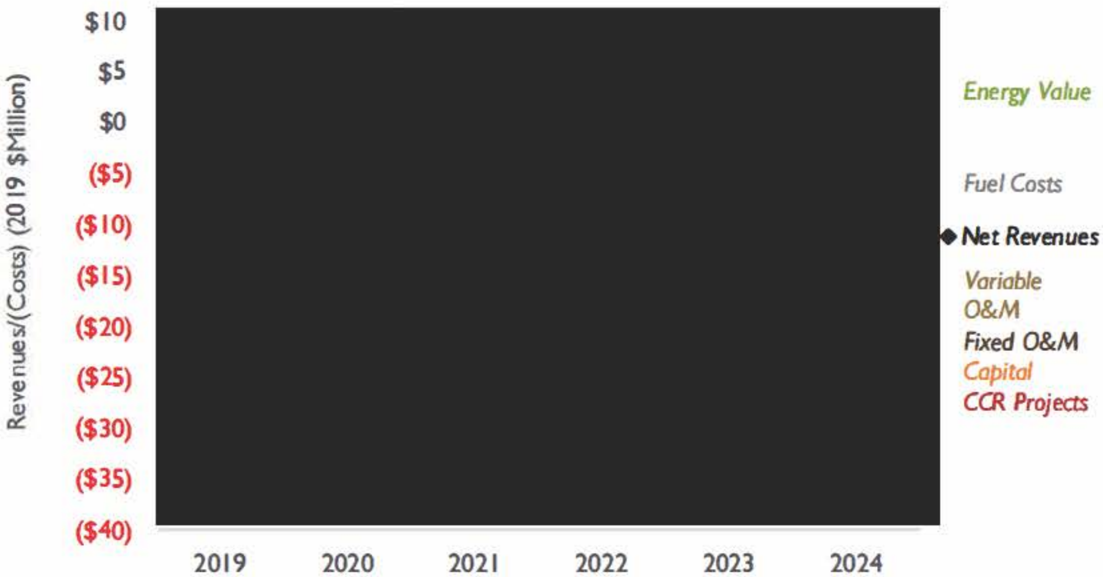
[redacted] [END CONFIDENTIAL]. Values for 2029 to 2040 are not shown, but the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Confidential Table 6. [redacted]

Unit	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Allen 1	[redacted]									
Allen 2										
Allen 3										
Allen 4										
Allen 5										
Cliffside 5										
Cliffside 6										
Marshall 1										
Marshall 2										
Marshall 3										
Marshall 4										
Belews Creek 1										
Belews Creek 2										

Confidential Figure 3 shows the projected energy value and cost streams for Allen 1, as well as the unit's net revenues between 2019 and 2024. In 2019, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for a unit that it planned to retire at the end of 2024. Results for the remaining DEC units are shown in Confidential Exhibit RW-3.

Confidential Figure 3. [redacted]



Q Describe how you evaluated the forward-looking economic performance of DEC's coal units.

A The net values presented are based on DEC data related to each unit's projected energy revenues, fuel costs, O&M costs, and capital costs.

DEC declined to provide the forecasted avoided energy costs or projected energy market prices requested through discovery. In response to discovery follow ups, the only resource DEC provided was their proposed avoided cost energy rate schedule from NCUC Docket No. E-100, sub 158.[22] Therefore, the Variable Rate for Annualized Energy of 3.03 cents per KWh from the attachment was used to calculate projected energy revenues for each unit. The rate was taken to be in 2018$ and converted to nominal dollars for the duration of the analysis period.[23]

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[22] DEC Response to Sierra Club DR 2-14, attachment "DEC Sierra 2-14 Avoided Cost Annualized Rates.pdf".

[23] DEC Second Supplemental Response to Sierra Club DR 2-14.

DEC directly provided unit-specific capacity, capacity factor, fixed O&M, fuel costs, and capital costs based upon their 2019 IRP studies.[24] DEC also provided unit-specific capital costs and fixed O&M costs for Allen 4, Allen 5, and Cliffside 5 based upon their 2019 depreciation study with accelerated retirement dates.[25] The values from the Company's "No CO2 Constraint" IRP analysis were used as given for all units except for Allen 4, Allen 5, and Cliffside 5. For those three units, the CapEx and fixed O&M data provided by the IRP study were replaced with the updated values from the depreciation study because they take into account the accelerated retirement dates. The generation, variable O&M costs, and fuel costs were adjusted to be zero in the years following the units' retirements, as opposed to the values the IRP study had assumed.

DEC directly provided forecasted ash management costs through 2040 by plant.[26] These costs were allocated to each unit using nameplate capacity.

Fuel, O&M, capital costs, and forecasted coal ash management costs were subtracted from energy revenues to arrive at net revenues for each plant and each year.

Q What are the implications of these uneconomic results for ratepayers?

A The continued negative values associated with DEC's coal units means that ratepayers will continue to pay for the Company's uneconomic operation of its coal fleet.

[24] DEC Response to Sierra Club DR 2-13, attachment "CONFIDENTIAL 2019 DEC NC SCDR_2-13_a-o_t_DEC_CONFIDENTIAL.xlsx".

[25] DEC Response to Sierra Club DR 2-5, attachment "CONFIDENTIAL 2019 DEC NC_SierraClub_DR2-5_Nov2019DECRetirementAnalysis.xls".

[26] DEC Response to Sierra Club DR 2-18, attachment "DEC SC 2-18.xlsx".

Q Do your findings regarding the recent negative values associated with DEC's coal units indicate that the Company should retire all of its coal units immediately?

A No. Retirement of DEC's entire coal fleet at once would likely lead to reliability issues in DEC's service territory. It is also possible that retirement of a portion of DEC's coal fleet may improve the economics of the remaining coal units. However, the recent net losses of DEC's coal units should, at a minimum, encourage DEC to perform a rigorous economic assessment of alternative retirement dates for each of its units.

Q Are there additional reasons that DEC should evaluate alternative retirement dates for its coal units?

A Yes. On October 29, 2018, Governor Roy Cooper signed Executive Order 80, which directed the North Carolina Department of Environmental Quality to develop a Clean Energy Plan. That Plan was released in October 2019, setting a goal to reduce emissions of carbon dioxide (CO_2) from the electric sector by 70 percent below 2005 levels by 2030.[27] In a separate docket, Duke Energy Progress stated that in order to reduce emissions commensurate with North Carolina goals, as well as its own corporate goals, it would need to accelerate the pace of coal plant retirements and replace those units with low-emitting resources.[28]

Duke Energy, DEC's parent company, also has its own carbon-reduction goals, which are to cut CO_2 emissions by 50 percent or more by 2030 and to attain net-zero emissions by 2050.[29]

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[27] North Carolina Department of Environmental Quality. 2019. *North Carolina Clean Energy Plan*. Available at: https://files nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[28] Duke Energy Progress. Response to Friesian Holdings Data Request 2-8. Docket No. EMP-105, Sub 0.

[29] Duke Energy. *Global Climate Change*. Available at: https://www.duke-energy.com/our-company/environment/global-climate-change.

Q What are your recommendations to the Commission with regard to any request for recovery of future capital investments at DEC's coal units?

A I recommend that the Commission place a cap on future capital expenditures intended to prolong the lives of the DEC units as generating assets, and require the utilities to come to the Commission for approval of any expenditure that exceeds that cap before the expenditure can be recovered from ratepayers. The cap could be lower for units with near-term retirement dates as indicated by the most recent depreciation study, e.g. Allen Units 1-4, with a service life that ends in 2024. The cap could also be contingent upon the results of DEC's unit retirement study, to be included with the 2020 IRP.

Similar action has been taken in other jurisdictions. The Georgia Public Service Commission, for example, recently applied a cap to capital spending at the utility's Bowen plant in the recent 2019 proceeding.[30]

VII. PRUDENCE OF DEC INVESTMENTS IN ITS COAL UNITS

Q Has DEC demonstrated the prudence of its historical capital investments in its coal units, for which it is seeking cost recovery?

A No. In order to demonstrate prudence in the context of utility planning, DEC would need to show that its decision to commit to a particular power plant construction project is justified. Planning prudence includes consideration of a reasonable set of alternatives, the use of appropriate models and methodologies, and the collection and application of current forecasts and data. Costs that are found by regulators to have been incurred imprudently should generally be disallowed from rates. Similarly, assets that are not used and useful should be removed from rate base. Customers should not be asked to bear the burden associated with unjustified system planning decisions.

[30] Georgia Public Service Commission. 2019. Docket No. 42310. Order Adopting Stipulation as Amended. Attached as Exhibit RW-4.

Q What do you mean by "used and useful" in this context?

A The "used" part of the "used and useful" standard is relatively straightforward. Specifically, regulators should determine whether a particular asset is physically used in providing service to customers. Examples of equipment not "used" in providing service can include power plants that have been retired from service, environmental retrofit equipment that is not operated, transmission or distribution equipment that has been removed from the grid, and previously installed meters that are uninstalled as part of a meter replacement program.

The "useful" portion is more complex, as a particular item can be used in providing service but not be economically useful. For example, there may have been a power plant construction project that was planned in a prudent manner but may operate at costs significantly higher than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee. In such a circumstance a regulatory commission may find that the plant is prudent and used, but not economically useful in providing service to customers.

Q Why are these ratemaking concepts important in this docket?

A DEC is effectively requesting that the Commission determine that its past and future capital expenditures represent prudent investments in its coal fleet. I understand that the Commission applies a presumption of prudence to utility expenditures in some circumstances. There have been no other dockets before the Commission to determine whether DEC's capital expenditures were prudent prior to the Company actually spending the money, or whether DEC's coal units are "used and useful." Therefore, it is important that the Commission consider the economics of each of the units when ruling on DEC's application in this docket. While the Commission might consider DEC's coal fleet "used" because it provides energy to ratepayers, given the fact that the coal units are providing energy uneconomically, and increasing costs to DEC ratepayers, they are not currently "useful."

Q Does DEC provide evidence in this docket of either prudence in its capital spending at its coal units or that they are used and useful?

A No. DEC witness Steve Immel testifies only to the used and usefulness of the gas conversions at Cliffside Unit 5 and 6 and Belews Creek Unit 1, stating that "The conversion of Cliffside Station and Belews Creek Unit 1 provides customers with flexibility to utilize the most cost-effective fuel. The compliance efforts and the conversion of Cliffside Station and Belews Creek Unit 1 are used and useful, providing customers reliable low-cost generation. The capital investments position the Company to provide safe, reliable, and efficient operation of these assets, with high quality performance."[31]

VIII. CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your conclusions.

A My primary findings indicate that all DEC's coal units operated uneconomically for at least the three years between 2016 and 2018. I estimate that each of the coal units had negative net value of between [BEGIN CONFIDENTIAL] [redacted] and [redacted] [END CONFIDENTIAL] from 2016 to 2018. Despite these net losses, DEC continues to determine unit retirement dates for its coal fleet based solely on depreciation studies and continues to invest in its uneconomic coal units.

My analysis shows that each of DEC's coal units will continue to operate uneconomically in the future. DEC has not provided any economic assessments of the continued operation of its coal-fired units, even as low gas prices and declining costs for renewables have disadvantaged many coal units across the country. Thus, the Company has not demonstrated that continuing to invest in its coal fired units is a prudent decision and provides value to ratepayers.

[31] Direct Testimony of Steve Immel. Page 7, lines 4-9.

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. I recommend that the Commission disallow past spending on capital projects incurred between the 2017 rate case and this rate case, given that the data show that all of DEC's units had negative net value in 2016 and 2017, and nine of DEC's thirteen units had net negative value in 2018. Capital spending during this time period should be disallowed until DEC provides evidence of an analysis demonstrating the value of the investment done at the time the investment decision was made.
2. I recommend that DEC consider operating its units seasonally and only during months of peak demand to minimize losses to ratepayers.
3. I recommend that the Commission place a cap on future capital expenditures intended to prolong the lives of the DEC units as generating assets, and require the utilities to come to the Commission for approval of any expenditure that exceeds that cap before the expenditure can be recovered from ratepayers.

Q Does this conclude your direct testimony?

A Yes, it does.

Summary of Direct Testimony of Rachel Wilson, for Sierra Club
Docket No. E-7, SUB 1214

My name is Rachel Wilson and I am a Principal Associate with Synapse Energy Economics, Inc., a research and consulting firm specializing in electricity industry regulation, planning, and analysis. At Synapse, my work focuses on a variety of issues relating to electric utilities, including integrated resource planning, resource adequacy, electric system dispatch, environmental regulations and compliance strategies, and power plant economics.

The purpose of my testimony is to evaluate the economics of the coal-fired units owned by Duke Energy Carolinas (DEC or the Company) and assess the prudence of the Company's capital investments in these units as well as its operation and maintenance costs.

Using data provided by DEC, I evaluated the net value of each of the Company's coal units between 2016 and 2018. The input data set included each unit's energy value, fuel costs, O&M costs, environmental costs, capital costs, ash management costs, hourly generation, and the DEC system lambda. These various costs that I mention were subtracted from each unit's energy value to arrive at annual net value. (Because the information provided by DEC on which I based my analysis is confidential, the Company has also deemed the dollar values resulting from my analysis confidential—that is the amount by which the costs to operate the units exceeded the value provided by the units.)

My primary findings indicate that all DEC's coal units—which include Cliffside Units 5 and 6, Belews Creek Units 1 and 2, Allen Units 1 through 5, and Marshall Units 1 through 4—operated uneconomically for at least the combined three-year period from 2016 through 2018. Despite these net losses, DEC continues to set unit retirement dates for its coal fleet based solely on its depreciation study, which does not reflect the actual economic value, or lack thereof, to ratepayers.

Summary of Direct Testimony of Rachel Wilson, for Sierra Club
Docket No. E-7, SUB 1214

In addition, my analysis shows that each of DEC's coal units will continue to operate uneconomically in the future. I conducted a similar analysis evaluating the forward-looking economic performance of DEC's coal units for years 2019 through 2040 and found that, based on DEC's projections, its coal units are likely to remain uneconomic through 2040. Each of DEC's units, with the exception of one, is projected to have a negative net value in each year from 2019 through 2028, and all units are projected to have negative net values for 2029 to 2040.

Nevertheless, DEC is seeking to recover $192.8 million for operations and maintenance expenses and $509.4 million for capital expenditures incurred at its four coal plants in 2018. Future O&M and capital costs could be even higher. DEC has not demonstrated the prudence of its coal unit costs for which it is seeking cost recovery. Specifically, the Company has not demonstrated that its decision to incur additional capital expenses at its individual coal units rather than retiring them is justified. Instead, the Company assumes that its coal units will continue to operate until the dates identified in its most recent depreciation study—that is, 2024 for Allen Units 1 through 5; 2026 for Cliffside Unit 5; 2034 for Marshall Units 1 through 4; 2037 for Belews Creek Units 1 and 2; and 2048 for Cliffside 6. These life span estimates were not based on economic analyses of alternative retirement dates.

In addition, DEC's continued operation of and investment in its aging coal fleet ignores Governor Roy Cooper's Executive Order 80 and the subsequent North Carolina Department of Environmental Quality Clean Energy Plan. That Plan, released in October 2019, sets the goal of 70 percent reduction of carbon dioxide emissions below 2005 levels from the electric sector by 2030. And Duke Energy has its own carbon-reduction goals of cutting carbon dioxide emissions by 50 percent or more by 2030 and to attain net-zero emissions by 2050. Continued investment in all of DEC's coal units does not reflect a plan to meet these emission reduction goals.

Summary of Direct Testimony of Rachel Wilson, for Sierra Club
Docket No. E-7, SUB 1214

Given this, and based on the findings of my analysis of coal unit economics, I have two recommendations for this Commission: first, that the Commission disallow past spending on capital projects incurred between the 2017 rate case and this rate case, given that the data show that all of DEC's coal units had negative net value in 2016 and 2017, and eleven of DEC's thirteen coal units had net negative value in 2018; and second, that the Commission place a cap on future capital expenditures intended to prolong the lives of the DEC coal units as generating assets, and require the utilities to come to the Commission for approval of any expenditure that exceeds that cap before the expenditure can be recovered from ratepayers.

MS. LEE: The witness is available for cross examination.

CHAIR MITCHELL: All right. Ms. Kells, you are up.

MS. KELLS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. KELLS:

Q. Ms. Wilson, my name is Andrea Kells. I'm here on behalf of Duke Energy Carolinas. Good morning.

A. Good morning.

Q. And you're here today testifying on behalf of the Sierra Club; is that correct?

A. That's correct.

Q. Would you agree the Sierra Club is an environmental organization?

A. Yes, I believe that they call themselves such.

Q. Are you familiar with one of the Sierra Club's projects called the Beyond Coal Campaign?

A. I am familiar with that, yes.

Q. And are you familiar with the stated goal of that campaign being to shut down all coal plants in the U.S., or work towards that goal?

A. Generally, yes.

Q. And are you aware of Duke Energy's carbon emissions goals of reducing such emissions by 50 percent below 2005 levels by 2030, and achieving that zero emissions by 2050?

A. I am aware of those goals, yes.

Q. Would you agree that, to achieve those goals, Duke Energy will need to transition away from relying on its remaining active coal plants going forward?

A. I believe that's true, yes. Though there are, I think, several model scenarios that show different pathways to achieving that carbon reduction goal.

Q. Would you agree that DEC has about 20,000 megawatts of total generation capacity on its system?

A. Subject to check, that sounds correct.

Q. Would you agree that about 6,700 megawatts of that amount is coal-fired capacity?

A. I -- it was my understanding that it was slightly higher than that number, but it could be based on a nameplate versus summer or winter reading.

Q. Okay. And if you want to reference it, it's on Company witness Immel's direct testimony on page 3, line 12.

A. Thank you.

Q. Would you agree that the Company, DEC, has an obligation to provide safe and reliability electric service to its customers?

A. Yes, I would.

Q. And would you agree that, as the Company makes that transition away from reliance on coal we discussed a moment ago, it has to make that transition while continuing to meet that obligation to customers?

A. That's correct, yes.

Q. Now, your testimony recommends that the Commission disallow recovery of all capital investments the Company made in its coal fleet between the previous rate case and this one; is that correct?

A. Yes. I believe, though, I placed that contingency on the fact that the Company, DEC, should present a demonstration that its units are, in fact, economic. And if it can't present such a conclusion, then at that point the capital expenditures should be disallowed.

Q. And so when you talk about the units being economic, are you referring to the analysis that you did of the coal fleet?

A. That's correct.

Q. And your analysis looked at what you termed the net economic value of the fleet?

A. It did.

Q. And you conducted that study in late 2019, early '20, I'm guessing, just based on when we filed the case and your testimony was filed?

A. That's right, yes.

Q. And you relied for that analysis on data the Company provided through discovery?

A. That's correct.

Q. So that data included actual known costs incurred to maintain the coal units during the 2016 to '18 time frame?

A. That's right.

Q. And it also included actual known marginal costs of electricity on the system during that same time frame?

A. In the form of a system wind-down, yes. I'm sorry, that reflects net energy value. In -- my analysis includes fuel costs, variable O&M, fixed O&M, and then capital expenditures.

Q. And your analysis wasn't intended and did not analyze what the Company should have done with the information available to it at the time it incurred those costs to maintain those units, did it?

A. It did not.

Q. And in your testimony, did you present any feasible alternative the Company should have chosen instead of making any of these investments?

A. The Company has an obligation to look at replacement alternatives, whether that be adding new generation, investments in energy efficiency or demand response. I didn't analyze any of those alternatives. My analysis simply looks at -- it's a cash flow analysis of the Company's coal-fired units, and it looks at the net energy value on the system, comparing the cost and energy benefits derived from the coal units over the 2016 to 2018 time period.

Q. Okay.

A. And it's not an IRP-like replacement analysis.

Q. Okay. And did your testimony identify any particular investment the Company should not have made?

A. No single investment, no. And as I point out in my testimony, the retirement of one unit would affect the relative economics of another. This doesn't look at the units as a whole; it takes them one by one. And if you were to look at the net energy values in my tables and in my testimony, you can see that they are, in fact, different for each of the units.

Q. And are you familiar with the standard for cost recovery in North Carolina utility rate cases?

A. Not specifically, no.

Q. Okay. Are you generally aware that the utilities seeking recovery must show that its costs were reasonably and prudently incurred?

A. That seems correct, yes.

Q. And would you agree that that standard is applied based on the information the utility had available to it at the time?

A. That's generally how prudence is determined, yes.

Q. And are you also generally aware that, if a party wants to challenge the utility's cost, that party must identify specific instances of imprudence and provide a prudent alternative the utility should have chosen instead?

A. I was not aware of that, no.

Q. Can you refer to what was premarked as DEC Exhibit 3.

A. Yes. Give me one second.

Q. Sure.

MS. KELLS: And, Chair Mitchell, this is

actually -- DEC Exhibit 3 is the February 24, 2020, final order in the Dominion rate case, E-22, Sub 562, and I believe that's been taken judicial notice of, and so we don't need to make it a cross exhibit.

CHAIR MITCHELL: Okay. And we have taken judicial notice of that -- of this decision.

Q. Okay. Ms. Wilson, just let me know when you're there.

A. I have it, yes.

Q. And would you please turn to page 121 of the order? The page number is at the bottom.

A. (Witness peruses document.)

I'm sorry, I don't actually see the page numbers on this document.

Q. Okay. So I will -- so you're looking at DEC Exhibit 3?

A. Yes. Let me look in a different application. Sorry.

Q. That's okay.

MS. LEE: I'm looking as well, and this is the document we downloaded from Duke's data site. There are no page numbers on my version either.

MS. KELLS: Sorry about that.

THE WITNESS: I have the PDF page 121.
Is the heading at the top "discussion," and
subheading "applicable legal principles"?

Q. That is right.

A. Correct, then I am there.

Q. All right. There is a paragraph that starts down there near the bottom of the page, and it is not completed. But the paragraph starts "when setting"; do you see that paragraph?

A. I do, yes.

Q. And if you go one, two, three, four, five lines down, there's a sentence that starts "challenging prudence"; do you see that?

A. I do.

Q. Would you please read that sentence.

A. "Challenging prudence requires a detailed and fact-intensive analysis, and the challenger is required to; one, identify specific and discrete instances of imprudence; two, demonstrate the existence of prudent alternatives; and three, quantify the effects by calculating imprudently incurred costs. Harris order at 14-15."

Q. Thank you. And I know you just read words on a page, but does that sound consistent of what I asked you before about the standard for challenging prudence?

A. It does sound consistent, yes.

Q. And are you familiar with the concept of the cost of property used and useful as it's used in North Carolina?

A. I'm generally familiar with the used and useful standard, yes.

Q. And, in fact, your testimony discusses your interpretation of that standard, doesn't it, on page 21?

A. It does.

Q. And in discussing the term "useful" -- I'm on page 21, I think this is around line 9 or 10.

A. This is in my direct?

Q. Yes. Your direct testimony, page 21.

A. (Witness peruses document.)

Okay.

Q. So I was on line 9 or 10. And so in discussing the term "useful," you said there that:

"Where a power plant was planned prudently but may operate at higher costs than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee, a Commission may find the plant prudent and used but not economically useful."

Did I read or paraphrase that correctly?

A. You did, yes.

Q. And you're not a lawyer, are you, Ms. Wilson?

A. I am not, no.

Q. Has this Commission ever adopted your definition of the word "useful" in applying this standard?

A. I don't know if this Commission has adopted that particular definition, no.

Q. Have you testified before this Commission before in a rate case?

A. Not in a rate case, no.

Q. Has any other commission -- utility commission accepted your specific interpretation of the term "useful" based on your testimony?

A. I can't recall offhand if I've ever put forth a definition of "useful" in testimony before a commission. I think the answer is no, but I may be wrong about the timing of testimonies that are filed.

Q. Okay. You've submitted testimony in several jurisdictions; is that right?

A. That's right.

Q. And so one of those, in addition to here in North Carolina, is you've testified on behalf of the Sierra Club in Georgia; is that right?

A. That's correct.

Q. And you cite to that case or one of them that you've been a part of in your testimony on page 20 when you make the recommendation the Commission put a cap on the Company's future capital investments in its coal fleet; do you recall that testimony?

A. I do, yes.

Q. And before we talk about the Georgia case, is it your understanding that, in North Carolina rate cases, when you look at costs incurred during a historical test year updated through a certain period to determine if they're reasonably and prudently incurred?

A. That's correct.

Q. And that's different, isn't it, than if the state used, for example, a forward-looking test year or some model that allowed the Commission and the parties to review investments in advance of incurring them; would you agree with that?

A. Using a historical year would be different than using a forward-looking year, yes.

Q. And so back on your testimony, on page 20, line 11, you cite to the Georgia Public Service Commission as having imposed a cap like you propose here?

A. That's correct. I'll note that that was in an IRP docket, not in a rate-case docket.

Q. Thank you for that clarification.

And you attach that order in that case as Exhibit 4 to your testimony, correct?

A. Yes.

Q. And the Georgia Commission adopted a stipulation in that case, didn't it?

A. It did.

Q. Did the Sierra Club sign on to that stipulation?

A. I can't recall.

Q. Well, if you will look at the order that you've attached as your Exhibit 4.

A. Give me one second.

Q. Sure.

A. (Witness peruses document.)

I am there.

Q. And will you turn to page 8 of that order.

A. I see that.

Q. And so near the bottom there is a sort of subheading that says "nonsigning party's positions"; do you see that?

A. I do.

Q. And then if you turn over to page -- well, there's page 9, and then if you go to page 10, near the bottom you can see that Sierra Club is listed as a nonsigning party?

A. I do see that.

Q. And so would you agree that Sierra Club was a nonsigning party to the stipulation in that case?

A. Yes, I would.

Q. And the Georgia Commission in that case specifically denied nonsigning parties' recommendations; did it not?

A. I believe so, yes.

Q. All right. Ms. Wilson, would you agree that the Company's coal units are subject to certain state and federal environmental requirements coming under CAMA, federal CCR rule, and ELG rules?

A. Yes, I would.

Q. And would you agree that almost half the capital investments the Company's made in its coal fleet and is asking to recover here were made to comply with those environmental requirements?

A. I would agree with that, yes. However, it's my understanding of the CCR rule, at least, that certain of the retrofit expenditures might have been able to be avoided if the Company's committed to retiring their coal units by a certain date. I don't specify in my testimony the volume or the amount of capital investment that might have been able to be avoided, but it's my understanding that there is a portion of that that might have been avoidable.

Q. Okay. Yeah. And so you kind of led me to my next couple of questions.

So is it your general understanding that some of those requirements had to be done regardless of whether the units continued to operate? Things like installing the lined basins, for example, had to be done regardless of whether a unit operates or not, right?

A. That's correct, yes.

Q. And then aside for projects like that, if the Company was going to continue to operate these units, there were additional projects that it needed to do; for example, the dry bottom ash conversions, correct; would you agree with that?

A. Yes, I would.

Q. And as you suggested a minute ago, if the Company had not done those additional environmental projects that were required in order to continue running those units, it would have needed to shut them down, correct?

A. That's right.

Q. In your opinion, was that a feasible path for the Company to have chosen, to have not done these projects and to shut down these units?

A. I haven't analyzed that in my testimony. My testimony simply looks at the net energy value over the three-year period. I'll note that my confidential Table 5, in fact, removes capital expenditures from the analysis. And I see similar results in 2016 and 2017 in that each of the units incurred net negative value. And that it was only in 2018, which had a very cold January period, that those units are then positive, with the overall effect being that the majority of them over the combined period have been that negative energy value.

Q. And your study that produced those results that you're discussing, your study didn't analyze how -- or consider how it would be feasible to shut down all those units and continue to meet service obligations, did it; that wasn't its purpose?

A. It did not. And, in fact, I say that reliability would likely be effected if the unit -- if all of the units were to shut down. And that it wasn't my recommendation, in fact, that DEC shut down all of those units immediately. But that it look at the unit retirements, stack those unit retirements and determine an economic pathway that's beneficial to ratepayers.

Q. And when you were talking about that in your testimony where you said that retiring the entire fleet would likely lead to reliability issues, what you just mentioned, what were you referring to by "reliability issues"?

A. Generally, that the lights would -- could potentially go out. As I think you know, utilities are required to hold a number of megawatts in excess of peak demands, so peak demand plus a required reserve margin. And we were talking about the total generating megawatts in Duke's fleet at the beginning of this question-and-answer period. And, you know, if the Company were to retire 7,000 of 20,000 megawatts, it would leave it with 13,000, which is not sufficient to meet peak load plus a required reserve margin.

There are other different reliability issues that could be caused by the retirement of an entire coal fleet, but, you know, that's the primary issue that I was referring to.

Q. Thank you. And do you think it's possible there could also be reliability issues with retiring, say, like a coal station or a subset of units, or did you look at that?

A. I didn't look at that in this testimony. It is certainly possible, depending on the location, but it's also possible that there are a number of solutions that could alleviate that reliability concern.

Q. And so I think you mentioned earlier about the Company hasn't -- well, let me rephrase that. Part of your testimony is that the Company's not justified these investments; is that correct?

A. That's correct, yes.

Q. Would you agree that an analysis of whether or not to do an investment at a particular unit would look at, first, the cost of that investment as a starting point?

A. It would certainly include the cost of the investment. I'll note that -- that, in many instances with coal-generating units across the nation, they are often operating at a net loss, and that includes units in vertically integrated territories, and coal units in market areas simply because of the competitive nature of gas-fired generation and renewables, which push marginal prices down. And, oftentimes, the operating constraints of coal units mean that those units are required to stay online operating at a higher cost even when they're uneconomic, just simply due to ramping constraints and startup and shutdown time periods.

So, you know, this is a challenge that coal units across the nation are facing, and, you know, DEC is certainly not alone in that.

Q. And would you find it reasonable that an analysis of whether to do an investment should also look at sort of the flip side of the cost of the investment, meaning any costs that might come up if the investment is not made and the unit needs to retire?

A. Could you give me an example of what you mean?

Q. Sure. For example, do you think it would be a good idea for the Company or any utility doing an analysis like this to look at the cost of any replacement generation that would be required if the unit were to retire?

A. That's one thing that the Company could look at, sure. And it's my understanding that, in the past, Duke has looked at replacement generation. But I would disagree with their methodology, in that Duke often looks at the retirement of a unit and compares that to replacement with a combined cycle unit or a combustion turbine. It's not, in fact, true that capacity needs to be replaced on a one-for-one basis.

Duke could, instead, take a portfolio approach where it looked at energy efficiency and renewable investments, a smaller gas-fired unit, if necessary. Capacity purchases are another option that could be examined. So the category of replacement generation could, in fact, take a variety of different forms.

Q. And have you looked at what portion of any that -- of the Company's coal-fired fleet it could have replaced with, you know, merchant purchases, purchases for merchant generation, rather than make some of these investments?

A. I haven't looked at that. You know, my understanding is that an all-source RFP issued by DEC would be the best way to get at that information as to what's available in the market.

Q. Are you aware there's not a great amount of excess merchant generation available in the Carolinas?

A. I am not certain that that's true. I have read the opposite in other documents. I haven't seen, you know, specific evidence one way or the other.

Q. Do you recall that the Company provided retirement analyses of Allen station and Cliffside unit 5 through discovery in this case?

A. That's correct, yes.

Q. So I'm going to ask you to look at DEC Exhibit 30.

MS. KELLS: And, Chair Mitchell, this is marked confidential, but I only have a few questions about it, and I've crafted them to not be directed at the confidential part. And so I think we can continue in public session, if you agree to that.

CHAIR MITCHELL: All right. Ms. Kells, I'm looking at the document now. We can proceed in open session. You know, this is a Duke document, so I trust you will avoid discussion of confidential information. So you may proceed.

MS. KELLS: All right. Thank you. So this was premarked as DEC Exhibit 30, so may we mark it now as DEC Wilson Cross Exhibit 1.

CHAIR MITCHELL: All right, for just abundance of caution, we're going to mark this confidential DEC --

MS. KELLS: Confidential.

CHAIR MITCHELL: -- Confidential DEC Wilson Cross Examination Exhibit 1.

MS. KELLS: Thank you.

(Confidential DEC Wilson Cross Examination Exhibit 1 was marked for identification.)

Q. Ms. Wilson, so this is the Company's response to Sierra Club Data Request 2-4.

. Have you seen this document -- set of documents before?

A. I have, yes.

Q. So just to orient us or other folks who may not have looked at it before, the first page of the exhibit is the cover page to this response, and then on the next page it's the request and then a narrative response. And then starting on page 5 -- the entire exhibit is numbered -- there is the study of the early retirement of Allen station. That is a presentation. And then on page 21 starts a series of tables, and that is the underlying Allen analysis. And then at the back, starting on page 86, is the Cliffside retirement study summary and presentation.

Do you agree that you see all those parts there?

A. I do, yes.

Q. Okay. And is this the information that you were recalling the studies that were done?

A. That's right, yes.

Q. And so I was just going to focus on page 21, which is the first page of the actual analysis of early retirement of Allen station. I had to print mine out really big, so I hope you were able to do the same or have it on a screen.

A. I have it on a screen, yes.

Q. Okay. And so -- and you can see that, just to make sure we're on the same page. It's page 21 and it's top left-hand corner. There's various labels, but one of them says 01.Econ Summary. Do you see that?

A. I do, yes.

Q. And I'll represent to you that this is the summary tab or the first tab of the Allen retirement file.

And so do you see on the most left-hand

column there's a series of costs -- types of costs and cost categories?

A. Yes.

Q. And then across the top, do you see that there are six different what we might call scenarios that each of these costs was evaluated in?

A. I do, yes.

Q. And would you accept, for purposes of these questions, that -- and I'm not going to say any of the numbers, but there are some numbers on this table that are -- if you are looking at color, that are red and in parentheses, and that those indicate where the Company concluded early retirement would avoid costs or save money?

A. Yes.

Q. And would you also accept that the black numbers not in parentheses indicate where the Company concluded that early retirement would incur additional costs?

A. Yes.

Q. And so you can see that, for many of these costs, there are savings in many cases and there are additional costs in many cases; would you agree with that?

A. Yes.

Q. Okay. And back on that left-hand column, in the list of costs, if you go down to the second category that's in bold and it has a green line, it's called capital and FOM costs; do you see that sort of in the middle of the table?

A. I do, yes.

Q. And several lines under that, there's a label for accelerated generation; do you see that?

A. Yes, I do.

Q. And then, again, without stating the numbers, in each scenario there are indicated accelerated generation costs for each of the six scenarios; do you see that?

A. I do.

Q. And then at the bottom of the table, it's labeled "Total retirement savings," and would you agree that, in four of the six scenarios, this study indicated that early retirement would result in additional costs to the Company?

A. Yes.

Q. So based on the results of this study, in your opinion, would it have been prudent for the Company to not make required investments in Allen and retire it early and incur greater costs than it would otherwise?

A. I will say that the results of this study do, in fact, indicate that, but that I would object to a number of the input assumptions that were made in this particular study.

Q. And then I think we've -- I think we've -- I might have asked you this question. If so, I apologize.

In preparing your testimony and analysis, you didn't look at the need for replacement capacity for any of the coal units if they were to shut down; is that right?

A. I did not. There -- first of all, it's unclear whether or not replacement capacity would be needed for all of the units. You know, these units are different sizes ranging from smaller side to the larger side. And if Duke is in a position of excess capacity, it may need not replace, you know, one or more of the smaller units. And there are, again, a number of different replacement options that could be considered.

I don't believe that a replacement needs to be one-to-one in terms of capacity, and so that is perhaps an issue where I would disagree with Duke's analysis.

Q. And you also didn't analyze whether a particular unit would, in fact, need replacement capacity, did you?

A. I did not. Again, you know, my analysis is meant to be more of a cash flow. I am, in fact, requesting that Duke look at a replacement for its coal units. And, you know, my analysis simply indicates kind of a rank order of the units in terms of net energy value in this docket. So it might be a starting point for replacement analysis, but it's certainly not meant to be a replacement analysis.

Q. Did you mention this study in your testimony or exhibits?

A. I did not, no.

Q. And we've been talking about it a bit, but did you analyze the data provided in these documents in preparing your analysis for testimony?

A. I looked at these data. I wouldn't say that I analyzed them, no. And it appears to me that this analysis was done using modeling software, and the name of that software appears in this document. I'm not sure if I'm allowed to say it.

Q. Let's not, just to be careful.

A. Okay. And I didn't employ any sort of modeling software in my analysis.

Q. And you have testified, correct, that the Company has not justified its investments in the coal fleet; is that right?

A. That's correct.

Q. But you decided not to mention this analysis in your testimony, correct?

A. I did not mention this analysis in my testimony, no.

Q. Did you use any of the information the Company provided through discovery to conduct a retirement study of your own with regard to any of the coal units?

A. Not conduct a retirement study in this docket, no.

Q. Thank you, Ms. Wilson.

MS. KELLS: Chair Mitchell, those are all my questions.

CHAIR MITCHELL: All right. Additional cross examination for the witness?

(No response.)

CHAIR MITCHELL: Any redirect for the witness?

MS. LEE: Just one or two,
Chair Mitchell.
REDIRECT EXAMINATION BY MS. LEE:
Q. Ms. Wilson, you were just discussing this Allen analysis with Ms. Kells, and understanding that the contents of it are confidential, please only answer this question in general terms, keeping that in mind.
You mentioned, in response to one of her questions, that you objected to a number of the input assumptions?
A. That's right.
Q. If you could discuss those without revealing anything confidential, could you please do so?
A. Sure. Ms. Kells referenced the accelerated generation, and this analysis looks at a couple of different options for that accelerated generation. And Duke's input assumptions around that specifically are an area in which I would disagree.
Q. Okay. And to your mind, is this type of analysis, and the one that was conducted for Cliffside, are those comprehensive retirement analyses?
A. No, I don't believe so. These analyses specifically are designed to look at the decision around whether to retire or continue to operate a coal

unit with a specific capital investment in mind. So, in these analyses, DEC was looking at upcoming environmental rules and whether or not it was more economically beneficial to incur those additional costs associated with compliance with the rule or retire those units.

And it's my opinion that now the economics of the United States coal fleet is such that coal units need to be analyzed on an ongoing basis to determine their economic value to ratepayers. It's not enough to look at these units when a specific larger capital investment is required, but to analyze them in an ongoing way to determine whether or not what I'll call sustaining CAPEX is economically beneficial to ratepayers.

Many of these units Duke's included are quite old, and they have lives that took on now past what they were intended to operate when they were constructed. So utilities can continue to invest capital in them to keep them operating, you know, past their originally intended useful lives, and that may not be in the best interest for ratepayers, particularly given the competitiveness of renewable energy today.

Q. Okay. And just one follow-up to that answer.
Given the age of Duke's fleet and the trends that we've seen in the U.S. coal industry -- electric generating industry, I should say -- would your opinion about the need for continuing evaluation, would that continuing evaluation have been needed back in 2015, say?

A. So back in 2015, the trend was -- utilities then were looking at -- they were in a similar situation, but this was with respect to the CSAPR and NOX rules which looked at regulations for SO2, NOX, and mercury. So utilities were faced with the decision then, which was to install an FGD primarily, or other emissions control technologies, or many of them looked at replacement generation with combined cycle or combustion turbine unit, depending on the size.
And the way that the economics kind of were trending in 2015 was that many of the smaller, older coal units, it was more economic to retire them, whereas a lot of the larger, newer units, it was more economic to continue operation with the installation of control technologies. And as -- you know, in just the five years since those dockets were coming up around the country, the new trend has been that larger and

newer units have also been retiring. And this is both because of, again, environmental rules and the investments necessary to comply with them, but it's also a matter of economics. And there are a number of coal-fired units that have retired or announced intent to retire in the next five years simply due to economic pressure from competing generators.

MS. LEE: Thank you. I have no further questions at this time.

CHAIR MITCHELL: All right. Questions from the Commissioners, beginning with Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: I have no questions.

CHAIR MITCHELL: Okay. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Nothing from me.

CHAIR MITCHELL: Duffley?

COMMISSIONER DUFFLEY: No questions.

CHAIR MITCHELL: Hughes?

COMMISSIONER HUGHES: Yes.

EXAMINATION BY COMMISSIONER HUGHES:

Q. If I understand your testimony, you seem to be saying clearly that you do not recommend the retirement of DEC's entire coal fleet, and at once would likely lead to reliability issues in the service territory.

How do you reconcile that recommendation with categorically excluding all costs of the coal fleet? I'm just trying to see how you would reconcile or explain that.

A. Sure. So my recommendation was to exclude the capital costs associated with keeping those coal-fired generators online until DEC could demonstrate that those units were economically necessary. And so that involves going back and showing, between 2016 and 2018, that they had, in fact, done an economic analysis demonstrating that those units were cost effective for ratepayers. I haven't seen evidence in this docket that DEC has done that. It may exist and the Company hasn't provided it, but I would -- if it does exist, I would like to see it, and have them provide it in support of their investments in their coal fleet.

Q. And if they had done that and they had seen everything was negative, would you still stand by that you would not want to retire the entire coal fleet immediately?

A. So DEC's analysis would, in fact, take into account replacement capacity, and that takes time to bring online. So, you know, my recommendation isn't that DEC retire its coal fleet now in 2020 or 2021, but rather, you know, it would need to look at replacement capacity in the instance where almost 7,000 megawatts of generation is retiring, determine what is the best economically for ratepayers and make those investments, instead of continuing to invest capital into units that aren't in the economic interest of customers in North Carolina.

Q. Okay. Thank you. No further questions.

CHAIR MITCHELL: All right. Commissioner McKissick?

COMMISSIONER McKISSICK: No questions at this time, Madam Chair.

CHAIR MITCHELL: All right. Questions on Commissioners' questions?

(No response.)

CHAIR MITCHELL: Ms. Lee, any questions

on Commissioner's questions?

MS. LEE: No, I don't. Thank you.

CHAIR MITCHELL: Okay. All right. At this time, Ms. Wilson, you may step down. Ms. Lee, I'll entertain a motion from you.

MS. LEE: Yes, please, Chair Mitchell. We now move that Sierra Club Wilson Exhibits 1 and 3 [sic], and Confidential Sierra Club Wilson Exhibits 2 and 3 be admitted into the record.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Ms. Lee, it will be allowed.

(Sierra Club Wilson Exhibits 1 and 4, and Confidential Sierra Club Wilson Exhibits 2 and 3 were admitted into evidence.)

CHAIR MITCHELL: Ms. Kells?

MS. KELLS: Yes. I move that DEC Wilson Cross Exhibit -- or Confidential DEC Wilson Cross Exhibit 1 admitted into evidence at this time.

CHAIR MITCHELL: All right. Without objection -- hearing no objection to that motion, it is allowed.

(Confidential DEC Wilson Cross

Examination Exhibit 1 was admitted into evidence.)

MS. LEE: And, Chair, we also request that the witness be excused.

CHAIR MITCHELL: All right. Ms. Wilson, you may step down, and you are excused. Thank you very much for your testimony today.

THE WITNESS: Thank you very much.

CHAIR MITCHELL: All right. At this point in time, I believe we are now with the Public Staff. Ms. Downey, you may call your witnesses.

MS. DOWNEY: Yes, Chair Mitchell. Public Staff would call Jack Floyd and James McLawhorn.

CHAIR MITCHELL: All right. I see Mr. McLawhorn. I'm looking for Mr. Floyd. Mr. Floyd, sing out so I can see you.

MR. McLAWHORN: Madam Chair, his office is just down from mine. I'll check to see if he's having a problem.

CHAIR MITCHELL: All right. Please do so.

MS. DOWNEY: Apologies for the delay.

(Pause.)

CHAIR MITCHELL: All right. While we have a minute, we will break for lunch at 12:30, and we will end our day today at 4:30 as we have been doing. Tomorrow we will begin at 8:30. Just putting you all on notice.

All right. I see Mr. McLawhorn is back. Do you have a report for us?

MR. McLAWHORN: Yes. He's getting on right now.

CHAIR MITCHELL: Okay.

MR. FLOYD: Sorry about that. I was down the hall.

CHAIR MITCHELL: Mr. Floyd, just in time. All right.

Whereupon,

JACK L. FLOYD AND JAMES S. MCLAWHORN,
having first been duly affirmed, were examined
and testified as follows:

CHAIR MITCHELL: Ms. Downey, you may proceed.

DIRECT EXAMINATION BY MS. DOWNEY:

Q. Mr. McLawhorn, we'll start with you.

Please state your name, business address, and present position?

A. (James S. McLawhorn) My name is James McLawhorn. My business address is 430 North Salisbury Street, Raleigh. I am the director of the Public Staff's energy division.

Q. Mr. McLawhorn, did you prepare and cause to be filed on February 18, 2020, direct testimony in this case consisting of 38 pages, an appendix and two exhibits?

A. Yes, I did.

Q. Do you have any corrections or changes to that testimony at this time?

A. I do not.

Q. If the same questions were asked of you today, would your answers be the same?

A. They would.

MS. DOWNEY: Chair Mitchell, I would move that the direct testimony of Mr. McLawhorn be copied into the record as if given orally from the stand, and that his exhibits be marked as prefiled.

CHAIR MITCHELL: All right. Ms. Downey, hearing no objection to your motion, it will be allowed.

(McLawhorn Exhibits 1 and 2 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony and Appendix A of James S. McLawhorn was copied into the record as if given orally from the stand.)

DUKE ENERGY CAROLINAS, LLC
DOCKET NO. E-7, SUB 1213
AND
DOCKET NO. E-7, SUB 1214

TESTIMONY OF JAMES S. MCLAWHORN

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

FEBRUARY 18, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is James S. McLawhorn. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Director of the Electric Division of the Public Staff, North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's analysis and recommendations concerning the cost-of-service (COS) methodology to be used in establishing rates for Duke Energy Carolinas, LLC (DEC or the Company) in this case. The Public Staff's recommendations are based on a review of the application; the testimony and exhibits (direct) of DEC's witnesses; DEC's responses to numerous data requests; and prior general rate cases of DEC, Duke Energy Progress, LLC (DEP), and Dominion Energy North Carolina (DENC), including the 2019 general rate case of DENC in Docket No. E-22, Sub 562. In addition, I will address the Commission's January 22, 2020 Order (January 22 Order) in this docket, directing the Public Staff to include information similar to that included in Public Staff witness Jack Floyd's testimony in Docket No. E-7, Sub 1146, regarding the differences between the COS methodologies specified in the January 22 Order. I will also offer testimony on additional COS methodologies for the Commission's consideration.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

I. General Discussion of Cost-of-Service

II. Discussion of Various COS Study Methodologies

III. Adjustments to Test Year Data

IV. Allocation of Transmission and Distribution Plant

V. Recommendations to the Commission

I. General Discussion of Cost-of-Service

Q. WHY IS THE COST-OF-SERVICE STUDY (COSS) IMPORTANT IN A GENERAL RATE CASE?

A. The cost-of-service study (COSS) is illustrative of how the utility incurs costs to provide all of its customers with safe, reliable, economical, and continuous electric utility service. It is important that all costs are considered in the COSS to ensure that the utility is reasonably able to recover its full costs to serve all of its customers, while also ensuring that all jurisdictions and customer classes bear the appropriate responsibility for the costs they impose upon the system.

Q. PLEASE BRIEFLY EXPLAIN THE PURPOSE OF A COST-OF-SERVICE STUDY, HOW IT IS DEVELOPED, AND HOW IT IS USED IN ESTABLISHING RATES.

A. Utilities use a COSS to determine how to allocate overall costs among jurisdictions and customer classes to establish rates based on an analysis of cost causation. Through an analysis of load characteristics, the COSS allocates or assigns the Company's rate base, expenses, and revenues to the appropriate jurisdictions and customer classes.

Data used in a COSS is based on the official accounting books and records of the utility. This data is obtained through load research and direct measurement and includes the number of customers and meters, the demand (kilowatts or kW) recorded during peak load periods, and the total energy (kilowatt-hours or kWh) used to serve each customer class. This cost causation analysis determines the costs each jurisdiction and customer class impose on the utility system. As explained by Company witness Hager on page 6 of her testimony, costs in a COSS are grouped according to function, then classified according to cost causation, then allocated or directly assigned to the appropriate jurisdiction or rate class.

The general principle underlying COS is that each jurisdiction, customer class, or, in some cases, individual customer should be responsible for an appropriate share of the costs that are planned for and incurred in order to serve it. Some costs can and should be directly assigned. Costs that cannot be directly assigned should be allocated using the methodology that most accurately and equitably reflects this underlying cost causation principle. Specifically with respect to production plant, the COS allocation methodology should account for the uses for which generation is planned and costs are incurred.

II. Discussion of Various COSS Methodologies

Q. WHAT COST–OF–SERVICE METHODOLOGY HAS DEC PROPOSED FOR USE IN THIS PROCEEDING?

A. DEC has proposed using the summer coincident peak (SCP) methodology to determine both jurisdictional and customer class cost responsibility in this case.

Q. IS THE SCP METHODOLOGY UTILIZED TO ALLOCATE ALL COSTS IN THIS CASE?

A. No. SCP is utilized only for the allocation of both production and transmission plant and related costs. Other costs are allocated on the basis of, among other things, non-coincident peak, energy, customer count, and revenues.

Q. DOES THE PUBLIC STAFF AGREE WITH DEC'S USE OF THE SCP COST-OF-SERVICE METHODOLOGY IN THIS PROCEEDING?

A. No. As explained below, the Public Staff recommends the use of the summer/winter coincident peak and average demand (SWPA) methodology for allocating production plant and production plant-related costs because it more accurately reflects actual generation planning and customer usage than does SCP.

Q. HOW ARE PRODUCTION PLANT COSTS ALLOCATED UNDER SCP?

A. Under the SCP methodology, production plant and related costs, such as depreciation and accumulated depreciation, purchased power capacity costs, and certain production operation and maintenance (O&M) costs are allocated based on the loads (that is, the level of demand) of a jurisdiction and its customers that occur during just one specific hour of the year -- the summer system peak. The remaining 8,759 hours of energy consumption are not recognized under this methodology for the purpose of allocating production plant cost responsibility of the North Carolina jurisdiction and its customer classes. In other words, the SCP looks at the summer system peak, and compares it to the peak loads of all jurisdictions and customer classes at that same single hour, and allocates <u>all</u> production plant, regardless of type and use of plant, based on a direct ratio of the jurisdiction and customer class loads to that single hour summer peak load.

Q. WHAT IS THE SIGNIFICANCE OF FOCUSING ONLY ON ONE SYSTEM PEAK HOUR RATHER THAN ALL HOURS?

A. As noted by witness Hager, the Company's 2018 SCP was 17,632 MW, which occurred on June 19, 2018 at the hour ending 5:00 p.m.; however, that was not the system peak for 2018. The 2018 system peak was 18,935 MW, which occurred on January 5, 2018 at the hour ending 8:00 a.m. The winter peak was the annual system peak in 2014 and 2015, as well, while the 2019 system peak occurred in July.

Thus, the winter peak was the Company's annual system peak in three of the last six years.

As observed in the Company's 2018 IRP[1] and in the 2019 IRP update,[2] DEC's annual coincident peak is believed to be moving to the winter from the summer season. In fact, in response to an intervenor data request, the Company identified that the peak load forecasts used in the 2019 IRP show the annual system peak occurring in January of every year for the period 2020-2026. Also, in response to another intervenor data request, the Company identified that for IRP planning purposes, it had forecast the 2018 annual peak to occur in the summer, by 99 MW over the winter peak, but in actuality, as shown above, the 2018 winter peak exceeded the 2018 summer peak by over 1,300 MW.

Further, DEC has shifted its generation planning to a winter-planning approach, beginning with its 2016 IRP. Winter peaks have a much different character than the summer peak. Winter peaks tend to occur in the morning and ramp up and down quickly over a few short hours. Summer peaks tend to occur in the late afternoon with a more gradual ramp up and down over several hours.

[1] Filed in Docket No. E-100, Sub 157.
[2] Also filed in Docket No. E-100, Sub 157.

By focusing solely on the one single coincident peak hour (winter or summer), the COSS can inappropriately assign costs to jurisdictions and particularly to the customer classes. Focusing on one single peak hour can result in certain customer classes not being allocated any production plant costs at all. Also, certain customer classes can be allocated much more of the production plant costs because they cannot avoid consumption during that single peak demand hour. While SCP, or any peak allocation, is a very simple COS methodology to comprehend, simplicity is not necessarily an appropriate goal for such a critical and important task of assigning the costs of production built for a variety of purposes.

Q. WHAT COST–OF–SERVICE METHODOLOGY DOES THE PUBLIC STAFF PROPOSE FOR USE IN THIS PROCEEDING?

A. As stated above, the Public Staff proposes using the SWPA methodology for allocating production plant and production plant-related costs in this case.

Q. HOW ARE PRODUCTION PLANT COSTS ALLOCATED UNDER SWPA?

A. Under the SWPA methodology, the fixed costs of production plant and production plant-related costs are allocated among jurisdictions and customer classes on the basis of a formula that contains two components. The first component, the “summer/winter peak” component, is based on the demands of the jurisdictions or customer classes in question at the time of the utility's summer[3] and winter peak demands. This component takes into account the hour when the load on the system is highest during both the summer months and the winter months. The second component, the "average" component, takes into account the energy consumed during all hours of the year and is calculated by dividing the total kilowatt-hour (kWh) sales for the year by the number of hours in a year to arrive at the average demand. This component recognizes that there is a load being served by the system over the course of all hours during the year. In other words, the first component is based on the peak demands at a particular time, and the second component is based on the average demand over an entire year. The two components are then weighted as explained below before determining the appropriate allocation factor.

Q. WHY ARE THESE TWO COMPONENTS USED IN THE ALLOCATION OF COSTS UNDER SWPA?

A. The SWPA methodology recognizes that some production plant costs are incurred primarily to provide sufficient capacity during peak periods, while other production plant costs are incurred because of the need to provide the lowest cost energy to customers during all

[3] As noted above, the summer peak demand is the sole basis for allocating production plant under the SCP methodology advocated by Company witness Hager.

hours. When there is a need for new capacity, generally three types of generation resources are considered: peaking units, intermediate or cycling units, and base load units. The selection of the type of unit is an economic decision based on the amount of energy required to meet customer load or the number of hours a unit is expected to need to operate each year. If the amount of energy required is low, peaking units are cost-justified due to their lower capital cost as compared to large base load units. However, if the amount of energy required is high enough, the lower energy cost (in cents/kWh) of capital-intensive base load units makes them more appropriate. Therefore, the magnitude of production plant costs incurred by the utility are not only a result of the one-hour summer and winter peaks, but also a result of the energy or hours-of-use requirement for which the plant was built. Unlike the SCP methodology proposed by Company witness Hager, that allocates all of the Company's production plant costs based on the single coincident peak, the SWPA methodology recognizes that a portion of plant costs, particularly for base load generation, is incurred to meet annual energy requirements and not solely to meet peak demand. Without an average component in the allocation factor, all production plant would be allocated based on the jurisdictional and customer class contribution to demands at the peak hour. Such an approach assumes that the Company's total production plant investment was made **only** to serve the peak load that occurs during one hour on a single day during the year. While serving peak load is clearly a driver of the Company's generation resource planning, another important component is the need to invest in new baseload generation that can serve customers' electricity needs throughout the year. For example, the Company's most recent addition of the high capacity factor W. S. Lee Combined Cycle Plant, as well as other advanced combined cycle facilities and historical investments in baseload nuclear, operate throughout the year to provide baseload energy to the Company's customers. These recent generating plant investments support the view that DEC's resource planning is driven by both the need to serve load at the peak hour as well as throughout the year. As such, these recent plant decisions align with the SWPA's approach of allocating plant costs and related expenses considering both the peak demand component and the average demand component of service.

Q. WHAT WEIGHTINGS ARE GIVEN TO THE TWO COMPONENTS UNDER THE SWPA METHODOLOGY?

A. The "summer/winter coincident peak" component is weighted by 1 minus the system load factor for the jurisdiction or class in question. The "average" component is weighted by the system load factor for the jurisdiction or class in question. For purposes of my testimony, "load factor" is defined as the ratio of total energy (kWh) usage for the year divided by the total usage that would have occurred if the demand of the jurisdiction or class had remained continuously at the average of the summer and winter peaks level throughout the entire year [total energy / (summer/winter average system peak times 8,760 hours)].

Q. WHY ARE THESE PARTICULAR WEIGHTINGS ASSIGNED TO THE TWO COMPONENTS UNDER SWPA?

A. The load factor is used as an estimate of the portion of production plant costs incurred primarily to meet the need for low-cost energy at all hours of the day and year, as distinguished from the need for sufficient capacity during peak periods. As a jurisdiction, or customer class, uses more energy during off-peak hours, its load factor increases, and the proportion of production plant costs needed for base load capacity rather than for peaking capacity will increase correspondingly. It is thus appropriate to use the load factor as the weighting for the “average” component of the allocation and to use one minus the load factor as the weighting for the “summer/winter peak” component. Together, these two components result in a factor that appropriately allocates fixed production plant costs based on actual planning and usage.

Q. WHY IS THE SWPA METHODOLOGY SUPERIOR TO METHODOLOGIES USING A SINGLE COINCIDENT PEAK?

A. The SWPA methodology recognizes and balances the impact on costs associated with the peak demand hours**,** as well as all other hours, and allocates those costs more appropriately than a single peak demand hour allocation methodology. The SWPA methodology addresses the distribution of production plant costs more accurately than other methodologies using a single coincident peak. As I have previously described, the SWPA methodology addresses two of the main factors considered by a utility when selecting the appropriate type of plant to build when new capacity is required. The first is the quantity of energy the plant must supply, and second is the peak demand the plant must meet. A single coincident peak methodology (like SCP) addresses the peak requirement of the plant selection process but places no value on the need to produce energy at any time other than one peak hour in the summer. The SWPA methodology, however, addresses both the peaks the utility must meet in the summer and winter seasons and, importantly, the energy the utility must supply its customers during the other 8,759 hours of the year. In addition, SWPA more closely matches the Company's actual production planning process, which determines the type and mix of resources that meet, at least cost, the customers' electricity needs during all hours of the year. DEC's 2018 Integrated Resource

Plan (IRP) filed with this Commission on September 5, 2018, in Docket No. E-100, Sub 157, and updated on September 3, 2019, identifies future capacity needs for natural gas-fired combined cycle and natural gas-fired combustion turbine production plants over the identified planning cycle.[4] The decisions leading to the identification of these specific least cost combinations of plant were not based solely on the one hour highest peak in the summer. Without a doubt, the amount of annual energy that these resources would be required to provide to the system was a major consideration in their selection.

Q. CAN YOU IDENTIFY OTHER SHORTCOMINGS OF THE SCP METHODOLOGY VERSUS THE SWPA METHODOLOGY?

A. Yes. One illogical outcome of the SCP methodology is that a customer class can avoid responsibility for <u>any</u> production plant cost if it has no consumption during the one-hour summer peak. In this case, the Company's Area Lighting, Street Lighting, and Flood Lighting customer classes are allocated <u>zero</u> production plant costs under SCP, even though they consume significant amounts of energy from the Company's base load plants during other hours of the year. Under a strict coincident peak allocation, these classes would not pay any fixed costs associated with production plant resources that are obviously used to power the lights throughout the

[4] DEC 2019 IRP Update Report, Docket No. E-100, Sub 157, p. 63 and p. 67.

year. Other customer classes also have significant energy needs, but have the ability through various options to manage those needs during certain times so as not to coincide with the system peak. Under the SCP methodology, none of the energy needs for load that was managed at the time of the summer peak would be used to allocate production plant to that class, even if the load existed during the remainder of the year. As a result, responsibility for the cost of production plant that was built and is used to meet the significant needs of that class year round falls on other customer classes that do not have the same ability or options to manage their electricity needs during the one summer peak hour. In short, they would receive the energy associated with the load they were able to manage for one single hour but present during the other 8,759 hours of the year, by paying only for the cost of fuel and variable O&M. The SWPA methodology, through its use of the average demand, would allocate some portion of system production plant costs to these customers, even though they place no, or a reduced, demand on the system during the respective summer and winter peak hours. Such customers still use and receive the benefit of the investments in production assets by paying lower energy costs, specifically fuel costs, during all other hours.

Another shortcoming of the SCP methodology is that cost allocation studies are highly dependent on the year in which they are conducted and are particularly susceptible to weather anomalies in a given year. This often results in swings in the magnitude and occurrence of the one-hour peak, which in turn can significantly alter the production plant cost allocation responsibility for certain jurisdictions and customer classes, depending on the test year chosen. For example, in 2014, 2015, and 2018, the differences between the summer and winter peaks were 1,773 MW, 1,137 MW, and 1,303 MW respectively, while in 2016, 2017, and 2019, the differences between summer and winter peaks were 969 MW, 679 MW, and 855 MW respectively. Weather was more extreme in 2014, 2015, and 2018, than the other years, and as DEC witness Jay Oliver states on page 29 of his direct testimony in this case, "[t]he number, severity and impact of weather events on DE Carolinas customers has been increasing significantly." By employing an average demand component based on total annual energy usage, which is less likely than single hour peak loads to vary significantly from year to year, the SWPA methodology is much less susceptible to these anomalies and resulting allocation swings.

Finally, an integrated system with economic dispatch that serves diversified loads with a least cost mix of diverse generating resources benefits all customers through lower average fuel costs than would be possible if the system were built to serve the individual, discrete load components. Such a system benefit requires that <u>all</u> customers be responsible for the fixed costs that make it possible. The SWPA methodology recognizes this benefit more accurately than the SCP methodology and allocates the production plant and related costs accordingly.

Q. WHY IS IT IMPORTANT TO USE BOTH THE SUMMER AND WINTER PEAKS?

A. While it is true that in recent history, DEC's summer peak has been greater than its winter peak with the exception of 2014, 2015, and 2018, as stated above the Company is now forecasting the winter peak to be greater than the summer peak from 2020-2026. In fact, as noted above in my testimony, the Company's test year winter peak is greater than its summer peak (18,935 megawatts (MWs) versus 17,632 MWs). Nevertheless, the annual summer peak is both real and significant, representing 98% or more of the annual winter peak in DEC's IRP forecasts for 2020-2026. In addition, in some years, certain jurisdictions (North Carolina Wholesale, South Carolina Retail, South Carolina Total) and some customer classes within a jurisdiction may have higher winter peaks than summer peaks and vice versa. As discussed previously, if only a one-hour peak is used to determine peak responsibility for cost allocation, jurisdictions or customer classes that are able to reduce a significant portion of their load at that one hour will be able to avoid paying for a significant portion of plant, even though their loads are present for other high demand periods of the year, including other very significant seasonal peaks. Averaging the summer and winter peaks together decreases the likelihood that a jurisdiction or class can shift load away from a single hour of the year and avoid any peak cost responsibility, notwithstanding its energy needs over the rest of the hours of the year. Thus, a more accurate cost allocation results from using SWPA.

Q. HAS THIS COMMISSION APPROVED SWPA AS THE APPROPRIATE COST ALLOCATION METHODOLOGY IN PAST GENERAL RATE CASE PROCEEDINGS?

A. Yes. This Commission has found SWPA to be the appropriate cost-of-service allocation methodology for Carolina Power & Light Company (now Duke Energy Progress, or DEP) in prior general rate case proceedings: Docket No. E-2, Subs 461, 481, 526, and 537. In finding that SWPA is the most appropriate cost of service methodology for DEP,[5] the Commission said the following in its Order:

> Without base load plants, CP&L [now DEP] would simply not be able to serve its high load factor customers. It is only appropriate that high load factor customers pay their share of the cost of these base load plants built primarily to serve them. The Commission is reluctant to shift the costs of these production facilities to further burden lower load factor

[5] See Finding of Fact No. 14 of the Order Granting Partial Increase in Rates and Charges in Docket No. E-2, Sub 537, issued August 5, 1988.

> customers, thereby reducing their load factors and ultimately, CP&L's system load factor still further.
> 78 N.C.U.C. 238, 367 (1988).

Q. WHAT HAS THIS COMMISSION RECENTLY HAD TO SAY ABOUT SWPA AS COMPARED TO OTHER COST ALLOCATION METHODOLOGIES?

A. In its DNCP rate case Order, dated December 21, 2012, in Docket No. E-22, Sub 479, this Commission, in approving SWPA as the appropriate cost-of-service methodology for DNCP (now Dominion Energy North Carolina, or DENC), stated the following at page 23:

> The cost of service methodology is a crucial component in establishing an electric utility's general rates. The methodology employed should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique characteristics of each class's peak demands and overall energy consumption. Based on the facts in this case, a methodology that does not properly consider the effect of overall energy consumption, but focuses mainly on peak responsibility would not properly represent the way in which [DNCP] plans for and provides its utility service and the way customers use that service. [Emphasis added]

The Commission further stated the following at page 24:

> In addition, the Commission is not persuaded that…any…cost of service methodology that only considers the jurisdictional and customer class peak demands is appropriate for the Company in this proceeding. The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the SWPA resulting in the most equitable sharing of the rate of return among DNCP's customer classes. [Emphasis added]

In its DNCP rate case Order, dated December 22, 2016, in Docket No. E-22, Sub 532, this Commission, in approving SWPA as the appropriate cost-of-service methodology for DNCP, stated the following at page 114:

> The Commission finds and concludes that DNCP has carried its burden of proof to show that the <u>SWPA</u> methodology is the <u>most appropriate cost of service methodology</u> to use in this proceeding to assign cost responsibility for production plant to the North Carolina jurisdiction and the Company's customer classes. … The cost of service methodology employed in establishing an electric utility's general rates should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique characteristics of each class's peak demands and overall energy consumption. Company witness Haynes testified extensively that the Company's investment in generating plant, including the recently placed in service Warren County and Brunswick County CC, are designed to meet the Company's system peaks and to deliver low cost energy throughout the year. Witness Haynes explained that the SWPA methodology appropriately recognizes that DNCP's system planning is designed to meet both the Company's peak and average system demands and energy needs of customers throughout the year. Both Company witness Haynes and Public Staff witness Floyd testified that the SWPA method appropriately matches allocation of production plant with DNCP's generation planning and operations. The Commission finds that, for purposes of this proceeding, the SWPA cost of service methodology properly recognizes the manner in which DNCP plans and operates its generating plants to provide utility service to customers in North Carolina. [Emphasis added]
>
> Based on the facts in this case, a methodology that does not properly consider the effect of overall energy consumption, but focuses mainly on peak responsibility

> would not properly represent the way in which the Company plans for and provides its utility service and the way customers use that service.
>
> The Commission is not persuaded that either the S/W CP methodology or the 1CP methodology is appropriate for the Company in this proceeding. Company witness Haynes and Nucor witness Goins provided calculations to compare the rates of return associated with the cost of service methodologies they advocated. The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the SWPA resulting in the most equitable sharing of the rate of return among DNCP's customer classes in this case.

Thus, what the Commission has found in past rate cases for DEP and DENC holds true today for DEC – the appropriate cost-of-service methodology must consider both overall energy consumption and peak demand. SWPA takes both into account; SCP does not.

Q. DOES THE PUBLIC STAFF CONSIDER A UTILITY'S IRP IN SELECTING THE APPROPRIATE COSS METHODOLOGY?

A. Yes. The Public Staff has historically taken the position that the cost-of-service methodology associated with any utility should be based on how that utility plans, builds, and operates its utility system. The best view of how a utility does this comes from the utility's integrated resource plan (IRP). Based on my review of DEC's 2018 IRP,[6] I believe the Company plans its system on the basis of meeting the

[6] The 2018 IRP filed in Docket No. E-100, Sub 157 was used because it was the last full IRP available.

peak demand plus a reserve margin at the peak hour of the year, and on the basis of satisfying the demand for energy at all other hours of the year. In other words, DEC plans and operates its utility system to provide the least-cost mix of generation resources to provide electric service for all hours of the year. Therefore, the methodology employed for a COSS should be based on the utility's efforts to provide electric utility service for all hours of the test year period, not a few hours of the year, and certainly not one single hour. And, as stated above, DEC, beginning in 2016, considers itself to be winter peaking, and for generation planning purposes, winter planning.

Q. WHAT IN DEC'S 2018 IRP SUGGESTS THAT THE UTILITY PLANS ITS SYSTEM TO MEET THE DEMANDS OF ALL HOURS OF THE YEAR AT LEAST-COST?

A. The first piece of evidence can be found on page 65 of the 2018 IRP Update. Chart 8-A identifies the forecast capacity of the utility system in 2020 and 2034. Approximately 64% of the capacity in 2020 comes from nuclear, coal, and combined-cycle (natural gas) resources. These resources are typically considered baseload capacity resources and are intended to operate at least 50% to 60% of the hours of the year (50% times 8,760 hours is 4,380 hours).

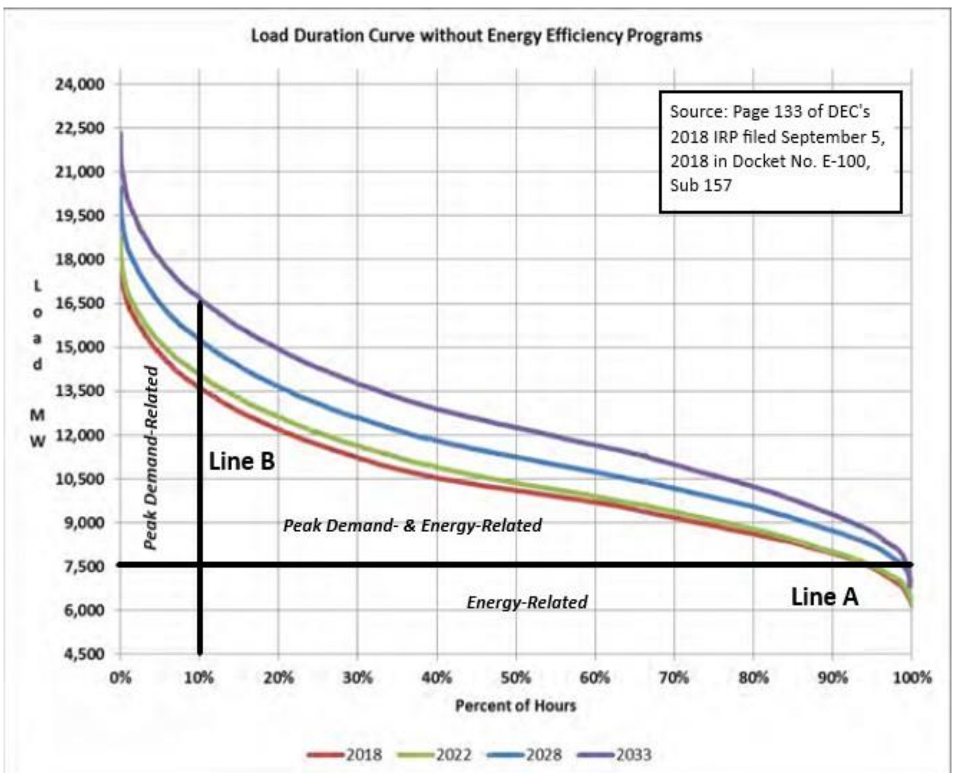
The second piece of evidence can be found on page 66 of the 2018 IRP Update. Chart 8-B[7] identifies the energy generated by fuel type, and clearly shows that for 2020 approximately 85% of the fuel used to produce energy comes from nuclear, coal, and combined-cycle resources.

The quantitative analysis that is in Appendix A of the 2018 IRP and the load duration curves in Appendix C of the 2018 IRP discuss the inputs (peak demand and energy load forecasts, existing resources, fuel prices, capital costs, and environmental constraints) used by the IRP model to determine the least-cost mix of generation resources for the next 15 years.

The load duration curve identifies the demand for resources needed over all hours of the year. For example, the graph below is taken from DEC's 2018 IRP. In general terms, all demand below line A is satisfied with baseload generation resources, which operate many hours of the year. This area is considered to be "energy-related." Demand to the left of line B is typically satisfied with peaking resources, which are usually combustion turbines that operate fewer than 10% of the hours in a year. This area is typically considered to be "demand-related." Everything else beneath the load duration curve is typically satisfied with a mix of baseload, intermediate, and

[7] Chart 8-B shows a combined DEC/DEP energy production by technology type.

peaking resources, and is considered to be <u>both</u> peak demand- and energy-related. Furthermore, the slope of the lines also informs how likely the model is to consider an energy resource versus a peak demand resource. In general terms, a flatter slope tends to lean more toward the selection of a baseload or more energy-intensive resource. A steeper slope tends toward the selection of a peaking resource. The IRP model will select the appropriate type of resource at least cost.



As a final point, both the quantitative analysis and development of the load duration curves are part of a technical and economic analysis that weighs the need to meet the one single peak demand hour, but also to satisfy the energy and demand requirements for every other hour of the year. The IRP model attempts to resolve this analysis by picking the least-cost mix of generation resources. In other words, it is the single peak demand that determines the total quantity of generation capacity needed by the system plus a reserve margin, but the type of generation resource (baseload, intermediate, or peaking) is most definitely determined on the basis of the energy requirements of the system that will be available from those capacity resources over all hours. The economics of energy production and its role in utility planning can be observed when one views the 100% increase in the percentage of combined cycle (CC) generation, while the role of coal and several other sources of power have diminished, as shown in Chart 8-A mentioned above. This increase in CC generation is largely due to two key drivers: the low costs of natural gas fuel, and the relatively lower capital costs per kilowatt for combined cycle units. Thus, DEC's portfolio of planned resources to meet its future load requirements takes into consideration both the fuel and capital cost of meeting its summer and winter peak demands, as well as the fuel and capital costs of satisfying its planned energy requirements for the other hours of the year.

Q. DOES DEC'S COSS METHODOLOGY ACCURATELY REFLECT THE COINCIDENT PEAK OF ITS STYSTEM?

A. No. Although the Public Staff believes that DEC is planning its system to meet both winter and summer peak, as well as total load throughout the year, if it were to use one peak in its COSS methodology, the system peak actually occurred in the winter. As mentioned earlier in my testimony, not only did the 2018 (test year) system peak occur in the winter, so did the system peaks in 2014 and 2015. In addition, DEC currently forecasts its annual system peaks to be winter peak dominant through 2026, and currently plans its generation needs based on a winter planning scenario.

Q. IS THE DEC WINTER PEAK AN ANOMOLY THAT SHOULD BE DISREGARDED?

A. No. As mentioned above, both the summer and winter peaks are significant now, and projected to remain so for the foreseeable future. As such, both peaks should receive weight in determining the peak load portion of production plant cost allocation.

Q. WOULD THE PUBLIC STAFF SUPPORT A CP COSS METHODOLGY USING ONLY THE WINTER PEAK?

A. No. The Public Staff would not support a winter peak CP (WCP) methodology, because it bases all production plant allocation solely on the one hour winter peak, and ignores the other 8,759 hours of the year, thus having similar flaws as the SCP methodology. All of the shortcomings identified above for SCP exist with the WCP methodology. Nevertheless, if the Commission were to approve a COSS methodology based solely on a one hour peak, which the Public Staff strongly opposes, the WCP methodology would be the appropriate methodology to use because DEC is now a winter peaking and winter planning system. As I demonstrate below, a WCP methodology would have much harsher impacts on certain classes of customers, particularly the Residential Class, than other methodologies.

Q. WHAT OTHER COSS METHODOLOGIES DID THE PUBLIC STAFF ANALYZE?

A. In addition to SWPA, SCP, and WCP, the Public Staff also analyzed the impacts of Summer/Winter Coincident Peak (SWCP), Four Coincident Peak (4CP), and 12 Coincident Peak (12CP) methodologies.

Q. WHAT IS THE SWCP COS METHODOLOGY?

A. The SWCP COS methodology utilizes both the annual summer and winter peaks for the system, jurisdictions, and classes, then averages them, and then computes allocation factors based on each jurisdiction's and class's contributions to the average summer and winter system peak. For the test year, those two peaks occurred in the months of January and June. SWCP is similar to SWPA in one way: it utilizes the same summer and winter peaks used in the peak allocation portion of SWPA; however, it does not incorporate any type of average demand component to reflect usage of generation plant over the entire year. It has the same shortcomings as the SCP and WCP, other than the fact that it tends to mitigate out extremes that occur at only a single seasonal peak.

Q. WHAT IS THE 4CP COS METHODOLOGY?

A. The 4CP COS methodology is similar to the SWCP methodology, except that it utilizes the four highest monthly peaks of the year. For the test year, those peaks occurred in the months of January, June, July, and August. As is the case of the SWCP methodology, it does not incorporate any type of average demand component to reflect usage of generation plant over the entire year.

Q. WHAT IS THE 12CP COS METHODOLOGY?

A. The 12CP methodology averages the highest monthly coincident peaks for each calendar month of the year. Because each monthly peak is weighted equally in calculating the annual average peak, any weather extremes from one month or one season are moderated. As with the other CP COS methodologies discussed above, however, there is no average demand component incorporated. The 12CP COS methodology has been historically utilized by the Federal Energy Regulatory Commission for its COS purposes.

Analysis of COS Methodologies

Q. HAVE YOU ANALYZED THE DIFFERENCES BETWEEN AND AMONG THE VARIOUS COS METHODOLOGIES DISCUSSED ABOVE FOR THIS CASE?

A. Yes. As can be seen in Exhibit JSM-1, I have compared the total energy requirements of the NC Retail Jurisdiction and the NC Retail Classes with the allocation of production plant by COSS methodology.

Q. WHY DO YOU BELIEVE THIS TYPE OF COMPARISON IS RELEVANT?

A. While I am not advocating for a perfect match between the allocation of production plant and total energy consumed by a jurisdiction or customer class, it is worthwhile to illustrate who is paying for the production plant as compared to who is getting the benefit of the relatively low cost energy produced by a combined, integrated system of generating facilities.

As Exhibit JSM-1 illustrates, all six methods allocate between 66.57% and 67.43% of production plant to the North Carolina retail jurisdiction. This analysis looks at the energy consumed by end users of Company owned generation, but does not include purchased power, which is allocated proportionally to jurisdictions and customer classes. The North Carolina retail jurisdiction consumes approximately 65.88% of system energy, so there is a relatively close match between energy consumption and the allocation of production plant.

However, on a North Carolina retail customer class basis, the differences between energy consumption and production plant allocation are more pronounced. For the Public Staff preferred SWPA allocation methodology Residential customers account for 38.29% of the energy consumed by the North Carolina retail jurisdiction, yet this class is allocated 44.60% of the production plant. Using the same percentage of energy consumption by jurisdiction and customer class, the other five methodologies all allocate greater amounts of production plant than the SWPA methodology, ranging from 45.96% for the Company preferred SCP, to 54.68% for WCP.[8]

At the other end of the spectrum are the large time of use general service and industrial customer classes, represented in Exhibit JSM-1 as OPTG and OPTI/T. These classes consumed 21.50% and 19.21% of jurisdictional energy respectively, yet are allocated 18.83% and 15.63% of production plant respectively under SWPA. Under SCP, OPTG and OPTI/T are allocated significantly less production plant: 18.21% and 13.49%, respectively. For WCP, the

[8] As noted previously in my testimony, DEC forecasts its system peaks and plans its system generation resources on the basis of it being a winter peaking system.

allocation percentages fall even more to 14.61% and 11.20%, respectively.

Q. DO YOU CONTEND THAT THERE SHOULD BE A PERFECT MATCH BETWEEN THE ENERGY CONSUMED AND THE PRODUCTION PLANT ALLOCATED?

A. No. If that were the case, the allocation methodology would be based solely on energy consumption. As I have stated previously in this testimony, system peaks are significant, and represent the total quantity of generation that must be present on the system to meet the highest demands. Thus, it is reasonable to allocate a portion of production plant based on one or more peaks. The SWPA allocates a significant portion, approximately 40%, of production plant on the basis of the summer and winter peaks. Because some customer classes have different load factors (a function of energy consumed from the system to peak demand placed on the system), there will necessarily and appropriately be a difference in the energy consumption percentages and the production plant allocation percentages. Classes with lower load factors such as the Residential Class will be allocated more production plant because of their relatively higher peak demand on the system. Nevertheless, it is important to recognize that energy consumed should play a role in the allocation of production plant as well. Of the six allocation methodologies represented in Exhibit JSM-1, only the SWPA reflects the spectrum of purposes for which system production plant is planned and built.

Q. HAVE YOU DONE AN ANALYSIS OF THE IMPACTS OF DIFFERENT COSS METHODOLOGIES ON THE JURISDICITONAL AND CLASS REVENUE INCREASES FOR THIS CASE?

A. Yes. Exhibit JSM-2 shows the overall rates of return on rate base for the North Carolina Retail Jurisdiction and various customer classes for the SWPA, SCP, and WCP COS studies. I have selected these three COSS methodologies to show the preferred methodology of the Public Staff (SWPA), the preferred methodology of the Company (SCP), and the methodology the Company should use if it were to continue using a single coincident peak methodology using its current yearly peak (WCP).

I have shown the rates of return under present revenues annualized (before any increase) and then, assuming the jurisdiction and each customer class is brought to the overall 7.58% return requested by the Company in this case, I have shown what the proposed increase or decrease would be under the three COS methodologies listed above.

As illustrated, the SCP produces the greatest North Carolina jurisdictional increase over present revenues at 9.35%, followed by the WCP at 9.19%, and SWPA at 8.95%.

For the Residential Class, the WCP produces the greatest required increase at 17.16%, followed by the SCP at 10.77%, and the SWPA at 9.79%.

For the General Service Classes, the WCP results in a 4.85% decrease over present revenues to bring the SGS Class to the overall ROR, and a decrease of 0.12% to bring the LGS Class to the same point. The SWPA results in a decrease of 3.23% for SGS and an increase of 2.62% for LGS. However, under SCP, the SGS Class would require a 2.89% increase and the LGS Class would receive a 5.98% increase.

For OPTG and OPTI/T, the SWPA results in an 11.85% increase and 13.00% increase respectively. The SCP results in an 11.48% increase and 8.49% increase, while the WCP produces significantly different results: 3.18% increase for OPTG and 2.07% increase for OPTI/T.

The Lighting and Traffic Signal classes have similar results under all three COS methodologies.

Q. TO WHAT DO YOU ATTRIBUTE THE DIFFERENCES IN RATES OF RETURN AND REVENUE INCREASE PERCENTAGES?

A. The rates of return differences are a result of the differences in the allocation of production plant based on either peak only, or a combination of peaks and overall energy use. The revenues under current rates do not change by methodology, and the allocation of other types of plant (e.g., transmission[9], distribution, customer, general) are not impacted by the way production plant is allocated. Some costs, such as depreciation, property taxes, and fixed O&M are dependent on the way production plant is allocated, however, and do impact net operating income by both jurisdiction and customer class.

The revenue increase percentages are a function of the rates of return. They represent the revenue increase required to bring the jurisdictional and class rates of return from present to the Company's requested overall rate of return of 7.58%.

[9] Transmission plant is impacted by the peak demand inputs utilized in the particular allocation methodology, but is not impacted by whether or not energy, or average demand, is utilized as an input. For example, for the SCP and WCP methodologies, the same peak inputs are utilized for both the production and the transmission plant allocation calculations. For the SWPA methodology, the average of the summer and winter peak demands is used as an input to calculate the allocation of transmission plant, but the average demand is not an input. The inputs for calculating transmission plant allocation are identical under both the SWPA and SWCP methodologies, but the production plant allocation inputs are different, due to the fact that SWPA utilizes average demand to allocate production plant, while SWCP does not.

III. Adjustments to Test Year Data

Q. DID DEC ADJUST THE TEST YEAR DATA USED TO CALCULATE THE COS ALLOCATION FACTORS?

A. Yes. As discussed on page 10 of DEC witness Hager's direct testimony, DEC adjusted the system peak to exclude demand for three wholesale contracts that expired at the end of the test year, and to add demands associated with two backstand arrangements. These adjustments are appropriate and should be made for any COSS to be utilized in this case. I reviewed the Company's test year peak demand and energy sales data related to this adjustment and believe the adjustment is appropriate for this proceeding.

IV. Allocation of Transmission and Distribution Plant

Q. EARLIER, YOU STATED THAT ALLOCATION OF PRODUCTION PLANT DOES NOT IMPACT THE ALLOCATION OF OTHER TYPES OF PLANT. DOES THE COMMISSION NEED TO CONSIDER CHANGES TO THE WAY TRANSMISSION AND DISTRIBUTION PLANT IS ALLOCATED?

A. Yes. As part of our analysis of DEC's Grid Improvement Program (GIP), we discovered that the benefits derived from some of the associated transmission and distribution assets are disproportionally related to the way the GIP transmission and distribution plant is allocated. For example, distribution plant allocation is heavily weighted towards the Residential Class, while the benefits derived from the GIP investments in distribution plant is heavily weighted towards the General Service and Industrial Customer Classes, as noted in the testimony of Public Staff witness Jeff Thomas. As recommended by witness Thomas, I believe that this is an area of cost allocation that deserves further study and analysis, and recommend that the Commission order DEC to study the allocation of GIP investments based on the realized benefits of those investments, and report its findings no later than the filing of its next general rate case.

V. Recommendations

Q. WHAT SPECIFIC RECOMMENDATIONS ARE YOU MAKING TO THE COMMISSION?

A. I have three recommendations to make.

- Adopt the SWPA COS methodology for the allocation of production plant because it most accurately and fairly reflects the planning and operation of DEC's production plant to meet the energy needs of its customers.
- Require DEC to study the allocation of GIP transmission and distribution investment/costs versus the benefits realized, and report its findings to the Commission no later than the filing of its next general rate case.

- Require DEC to solicit formal input from the Public Staff and other interested intervenors to this proceeding in developing its analysis of the allocation of GIP transmission and distribution investment/costs versus the benefits realized.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JAMES S. MCLAWHORN

I graduated with honors from North Carolina State University with the Bachelor of Science Degree in Industrial Engineering in May of 1984. I received the Master of Science Degree in Management with a finance concentration from North Carolina State University in December of 1991. While an undergraduate, I was selected for membership in both Tau Beta Pi and Alpha Pi Mu engineering honor societies.

I began my employment with the Public Staff Communications Division in June of 1984. While with the Communications Division, I testified before the Commission in general rate proceedings regarding matters of telephone quality of service.

In September of 1987, I was employed by GTE-South as an engineer in the Capital Recovery Department. I was responsible for analysis and recommendations to Company management regarding appropriate depreciation rates for recovery of the Company's capital investments.

I began my employment with the Electric Division of the Public Staff in November of 1988. I assumed my present position as Director of the Electric Division in October of 2006. It is my responsibility to supervise and make policy recommendations on all electric utility matters before the Commission.

I have testified previously before the Commission in numerous proceedings including Virginia Electric and Power Company Rate Cases Docket No. E-22, Subs 314, 333, 412, 532, and 562; in Duke Energy Carolinas, LLC's Rate Cases Docket No. E-7, Subs 487, 909, 989, and 1146; in Duke Energy Progress, LLC's Rate Cases Docket No. E-2, Subs 1023 and 1142; in New River Light and Power Company Rate Cases Docket No. E-34, Subs 28 and 32; in Nantahala Power and Light Company Rate Case Docket No. E-13, Sub 157; in the Application of Dominion North Carolina Power to join PJM in Docket No. E-22, Sub 418; in Duke Power Company's request to merge with in Duke Power Company's request to merge with Cinergy Corporation in Docket No. E-7, Sub 795; in Dominion Energy, Inc.'s request to merge with SCANA Corporation in Docket No. E-22, Sub 551; in Duke Energy Carolinas, LLC's request for approval of its Save-A-Watt cost recovery model in Docket No. E-7, Sub 831; in Duke Energy Carolinas, LLC's solar distributed generation program in Docket No. E-7, Sub 856; and, in the Generic Investigation into Section 111 of the 1992 Energy Policy Act in Docket No. E-100, Sub 69.

Q. Mr. McLawhorn, further, did you caused be filed on July 31, 2020, testimony supporting the second partial stipulation between the Public Staff and the Company consisting of seven pages?

A. I did.

Q. Do you have any corrections or changes to that testimony at this time?

A. I do not.

Q. If the same questions were asked of you today, would your answers be the same?

A. Yes, they would.

MS. DOWNEY: Chair Mitchell, I would move that the testimony of Mr. McLawhorn supporting the second partial stipulation be copied into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Ms. Downey, it is allowed.

(Whereupon, the prefiled testimony supporting the second partial stipulation of James S. McLawhorn was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1187

Testimony of James S. McLawhorn Supporting Second Partial Stipulation

On Behalf of the Public Staff

North Carolina Utilities Commission

July 31, 2020

Q PLEASE STATE FOR THE RECORD YOUR NAME, ADDRESS, AND PRESENT POSITION.

A. My name is James S. McLawhorn. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Director of the Public Staff – Electric Division.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE ON FEBRUARY 18, 2020?

A. Yes.

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

A. The purpose of my testimony is to support the Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation) filed on July 31, 2020, between Duke Energy Carolinas, LLC (DEC or the Company), and the Public Staff (Stipulating Parties) regarding certain issues related to the Company's pending application for a general rate increase.

Q. WHAT BENEFITS DOES THE SECOND PARTIAL STIPULATION PROVIDE FOR RATEPAYERS?

A. From the perspective of the Public Staff, among the most important benefits provided by the Second Partial Stipulation are:

(a) A significant reduction in the Company's proposed revenue increase in this proceeding; and

(b) The avoidance of protracted litigation by the Stipulating Parties before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, the Public Staff believes the Stipulation is in the public interest and should be approved.

Q. WHAT ARE THE SPECIFIC AREAS OF AGREEMENT BETWEEN THE STIPULATING PARTIES IN THE SECOND PARTIAL STIPULATION?

A. The Stipulating Parties were able to reach agreement on the following issues in the Second Stipulation:

- The parties agree to a return on equity of ROE of 9.6% - This ROE is below the 2020 average for vertically integrated utilities, and is the lowest ROE for an investor-owned utility in North Carolina in at least 30 years (in anyone's memory currently on the Public Staff);
- The parties agree to a capital structure ratio for each company of 52%/48% – This ratio is very close to DEC's current capital structure;
- The parties agree that DEC should return federal unprotected EDIT over five years, NC EDIT over two years, and deferred revenues over two years – this is consistent with the treatment of EDIT for other utilities;
- The parties agree to the Company's request for deferral accounting treatment for the following programs, as described in witness Oliver's Exhibit 10, limited to the estimated three-year capital budget period of 2020-2022: SOG (all subprograms including Capacity and Connectivity, Segmentation and Automation, ADMS), IVVC (DEC only), Conversion to CVR (DEP only), ISOP, Transmission System Intelligence, Distribution Automation, Power Electronics, DER Dispatch Tool, and Cyber Security. For all other GIP investments proposed by the Companies in these dockets,

the Companies agree that they should withdraw their request for deferral accounting;

- DEC should update to its May 2020 cost of debt, which is 4.27%;
- DEC may update plant through May 2020. Its revenues should be updated through May, but only 75% should be allowed to recognize the uncertainty regarding effects of COVID. The update should include benefits and executive compensation;
- $19.1 million should be disallowed on the Clemson Combined Heat and Power Project on a system basis;
- Coal ash capital projects such as dry ash storage, STAR water treatment project deferrals should be amortized over eight years;
- For purposes of this case only with no precedential effect, the Public Staff accepts the Summer Coincident Peak (SCP) cost of service allocation methodology;
- This acceptance of the SCP cost of service allocation methodology should have no impact on the rate design study proposed by Public Staff witness Floyd and endorsed by DEP and DEC witness Pirro. DEC also agrees to conduct an analysis of various cost of service study methodologies; and

- In addition to $6 million DEC has agreed to contribute in its settlement with the North Carolina Sustainable Energy Association, the North Carolina Justice Center, the North Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy to the Helping Home Fund, DEC agrees to contribute $5 million to assist low income customers with payment of their bills.

Q. ARE THERE ANY AREAS ABOUT WHICH THE STIPULATING PARTIES DID NOT REACH AGREEMENT?

A. Yes. The Stipulating Parties did not reach agreement regarding the following:

- <u>Coal ash costs</u> - Cost recovery of the Company's coal ash costs, recovery amortization period and return during the amortization period;
- <u>Adjustment for Hydro Station Sale</u> - Whether the Company's proposed amortization period of seven years of the loss on the sale should be approved versus Public Staff's recommendation of a 20-year amortization period;
- <u>Depreciation Rates</u> – The depreciation rates appropriate for use in this case, including the Company's proposal to shorten the lives of certain coal-fired generating facilities ; and

- any other revenue requirement or non-revenue requirement issue not specifically addressed in the First Stipulation, the Second Stipulation, or agreed upon in the testimony of the Stipulating Parties.

The Public Staff fully supports its filed positions on these particular issues, and intends to demonstrate the appropriateness and reasonableness of its positions through litigation in this case.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Q. Mr. McLawhorn, do you have a summary of your direct and second stipulation supporting testimony that was served to the other parties and the Commission?

A. Yes.

MS. DOWNEY: Chair Mitchell, I would move that Mr. McLawhorn's summaries of his direct and second stipulation supporting testimony be moved into the record as if given orally from the stand.

CHAIR MITCHELL: Hearing no objection, that motion is allowed.

(Whereupon, the prefiled summary of testimony of James S. McLawhorn was copied into the record as if given orally from the stand.)

Summary of the Testimony of James S. McLawhorn

Docket No. E-2, Subs 1213 and 1214

The purpose of my testimony is to provide the Public Staff's recommendation on the appropriate cost-of-service (COS) methodology for use in this case.

The Public Staff believes the appropriate methodology is the Summer/Winter Peak and Average methodology (SWPA). The Company has proposed the use of the Summer Coincident Peak methodology (SCP).

When the Company is selecting the appropriate type of generation plant to build, it must consider the quantity of energy the plant will be required to supply as well as the peak demand the plant must help to meet. The SWPA methodology recognizes and reflects the fact that the Company plans its system to meet the demands customers place on its generation plant throughout the year.

On the other hand, the SCP methodology assigns responsibility for generation plant and plant-related costs based solely on one single hour out of the entire year. Under SCP, a customer class can avoid all production plant cost responsibility by having no consumption at the time of the one hour summer peak.

In addition, I compare a number of other COS methodologies, including those included in the Commission's January 22, 2020 Order in this case.

Finally, I recommend that DEC study the allocation of Grid Improvement Program (GIP) transmission and distribution investments and costs versus the benefits realized, and report the its findings to the Commission by the filing of its next general rate case. In his review of the cost-benefit analyses of the various GIP programs, Public Staff witness Jeff Thomas found that the benefits of many of the programs are heavily weighted towards non-residential customers, while the costs, particularly for distribution, are not recovered in the same manner under current cost allocation methods; thus, my recommendation for the Company to study this issue, with input from the Public Staff and other interested parties, and report back to the Commission on the results. This study is even more critical now, given the Company's settlements with other parties to this case regarding the allocation of GIP costs.

This concludes my summary.

Summary of the Second Partial Stipulation Testimony

of James S. McLawhorn

Docket No. E-7, Subs 1187, 1213, and 1214

The purpose of my partial settlement testimony is to support the Second Agreement and Stipulation of Partial Settlement (Stipulation) between Duke Energy Carolinas, LLC (DEC or Company) and the Public Staff.

The Stipulation, as filed on July 31, 2020, sets forth agreements between DEC and the Public Staff on a number of areas impacting the overall revenue requirement in this proceeding including: (1) excess deferred income taxes, (2) cost of capital, (3) the Company's Grid Improvement Plan, (4) cost of service, and (5) accounting adjustments. Other areas of agreement include: (1) May 2020 updates, (2) principles surrounding class revenue apportionment, (3) additional cost of service studies, (4) a comprehensive rate design study, and (5) audits and reporting obligations.

Unresolved areas that impact the overall revenue requirement about which DEC and the Public Staff have not reached agreement in this case include: (1) recovery of coal ash costs, (2) amortization period for the loss on the sale of certain hydroelectric facilities, and (3) depreciation rates.

Despite being only a partial settlement of issues in this case, the Stipulation still provides two important benefits for ratepayers:

(a) A significant reduction in the Company's proposed revenue increase in this proceeding; and
(b) The avoidance of protracted litigation between DEC and the Public Staff before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, I believe that the Stipulation is in the public interest and encourage the Commission to approve it.

This concludes my summary.

MS. DOWNEY: And we'll move to Mr. Floyd.

DIRECT EXAMINATION BY MS. EDMONDSON:

Q. Mr. Floyd, you have previously testified during the consolidated portion of the hearing?

A. (Jack L. Floyd) Yes.

Q. And so we already introduced you, but go ahead and give your name and title again, please.

A. I'm Jack Floyd, engineer with the energy division of the Public Staff.

Q. And, Mr. Floyd, since the consolidated hearing, you filed in this docket an errata to your first supplemental testimony that was entered into the record at the consolidated hearing, as well as four corrected exhibits. And you also filed second supplemental testimony consisting of 14 pages and 4 exhibits, both of those on September 8, 2020, correct?

A. Yes.

Q. In regard to the corrected first supplemental testimony, besides the corrections that you filed on September 8th, do you have any further changes or corrections?

A. Not at this time, no.

Q. So if I asked you the same questions today, would your answers be the same as the corrected testimony?

A. They would.

Q. And, Mr. Floyd, in regard to the second supplemental testimony, do you have any changes or corrections to that prefiled second supplemental testimony?

A. I do not.

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

A. They would.

Q. Do you have any changes or corrections to the exhibits to your second supplemental testimony?

A. No.

Q. And I missed a question. Did you have any further changes or corrections to the corrected exhibits to your first supplemental testimony?

A. No, I do not.

Q. Okay. And did you prepare a summary of your direct first supplemental and second supplemental testimony?

A. Yes, I did.

Q. Okay.

MS. EDMONDSON: Chair, Mr. Floyd's

direct and original first supplemental testimonies were entered and copied into the record in the consolidated hearing, and the exhibits to those testimonies were marked for identification at that time.

So today I would like to move that the prefiled errata to Mr. Floyd's first supplemental testimony, Mr. Floyd's first supplemental testimony as corrected, his second supplemental testimony, and summary be entered into the record in this proceeding, and copied into the record as if given orally from the stand. And that Mr. Floyd's exhibits attached to the corrected first supplemental testimony and the second supplemental testimony be marked for identification as Floyd Corrected First Supplemental Exhibits 1 through 4, and Floyd Second Supplemental Exhibits 1 through 4.

MS. CRESS: Chair Mitchell, this is Christina Cress with CIGFUR. I would object to the admission of Mr. Floyd's second supplemental testimony for the same reasons that I provided in detail on the record yesterday morning. I will spare the Commission those details here, because I believe I sufficiently belabored evidentiary objections concerning his second supplemental testimony yesterday morning, but I would just like to note my renewed objection for the record. Thank you.

CHAIR MITCHELL: All right. Noting the renewed objection of counsel for CIGFUR III, I will allow your motion, Ms. Edmondson.

MS. EDMONDSON: Thank you.

(Floyd Exhibits 1 through 4, Supplemental Floyd Exhibits 1 through 4, Corrected Supplemental Floyd Exhibits 1 through 4, and Second Supplemental Floyd Exhibits 1 through 4 marked for identification.)

(Whereupon, the prefiled direct and Appendix A, supplemental, errata to first supplemental, and second supplemental testimony as well as summary of the testimony of Jack L. Floyd was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

TESTIMONY OF JACK L. FLOYD
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

FEBRUARY 18, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jack L. Floyd. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an Engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's analysis and recommendations concerning:

1. The class rates of return (ROR) on rate base under present rates and the principles the Public Staff considers in evaluating proposed revenues requested by Duke Energy

Carolinas, LLC (DEC or the Company) and the assignment of revenues by customer class to be used in setting rates;

2. DEC's proposed modifications to certain rate schedules;
3. The status of the Company's Advanced Metering Infrastructure (AMI) Project;
4. The Company's Prepaid Advantage Program; and
5. The Commission's January 22, 2020 order regarding low-income rates and the minimum bill concept (Affordability Order).

The Public Staff's recommendations are based on a review of the application and Form E-1 filed by DEC, the direct testimony and exhibits of Company witnesses, and DEC's responses to numerous data requests from the Public Staff and other intervenors to this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND YOUR RECOMMENDATIONS.

A. I reviewed the testimony and exhibits of Company witnesses Arnold,[1] Hager, Henning[2], McManeus, Oliver, Pirro, and Schneider, along with Items 39, 40, 42, and 45 of the Company's Form E-1 filing,

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[1] Company witness Marc Arnold's testimony was adopted by Teresa Reed in a January 14, 2020 filing.

[2] Company witness James Henning's testimony was adopted by Larry Hatcher in a December 20, 2019 filing.

various accounting adjustments, and other information provided in response to data requests, regarding the topics listed above.

More specifically, my testimony recommends the following:

1. That any proposed revenue change be apportioned to the customer classes such that:
   a. Any revenue increase assigned to any customer class is limited to no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
   b. Class RORs are maintained within a band of reasonableness of ± 10% relative to the overall NC retail ROR;
   c. All class RORs move closer to parity with the NC retail ROR; and
   d. Subsidization among the customer classes is minimized;
2. That the proposed modifications to the Company's rate schedules are reasonable for purposes of this proceeding;
3. That the Commission order a comprehensive rate design study that will address rate design questions related to, among other things:
   - Firm and non-firm utility service, and the degree of customer-owned generation receiving both types of service,
   - Various types of end-uses such as electric vehicles (EVs), microgrids, energy storage, and distributed energy resources (DERs),
   - The formats of future rate schedules (basic customer charges, demand charges, energy charges, etc.),
   - Marginal cost versus average cost rate designs and pricing,
   - Unbundling of average rates into the various functions of utility service (i.e., production,

transmission, distribution, customer, general/ administrative, etc.),

- Decoupling revenues from sales; and
- Socialization of costs versus categorization of specific costs and corresponding impact on rates/revenues;

4. That the Company's Prepaid Advantage program be approved; and
5. That the Commission order the convening of a stakeholder process that is tasked with addressing affordability issues for low-income residential customers.

CALCULATION OF CLASS RORS AND ASSIGNMENT OF REVENUES

Q. HOW ARE RORS USED IN DETERMINING REVENUE ASSIGNMENT?

A. RORs serve as an indicator of how the revenues produced by the various customer classes cover the costs to serve those classes. They also serve to inform how any additional revenues will be apportioned to the customer classes. Any ROR that is less than the overall system or jurisdictional ROR indicates that the revenues received from a specific jurisdiction or customer class do not fully cover its share of system costs. Conversely, an ROR that is greater than the overall system or jurisdictional ROR indicates that a jurisdiction's or class's revenues exceed the necessary cost coverage. While it is appropriate to address revenue cost recovery inequities as revealed through RORs, it is equally important to keep in mind that such an assignment is based on a snapshot in time of the Company's cost and load data. A different timeframe, test year period, or other perspective would likely yield a different representation of cost causation and revenue assignment. Due to the variability in RORs, the Public Staff has historically targeted a ±10% "band of reasonableness" for class revenue assignment as discussed in more detail later in my testimony.

Q. PLEASE DISCUSS THE PUBLIC STAFF'S GOALS IN ASSIGNING A PROPOSED REVENUE INCREASE.

A. The Public Staff believes that assignment of a proposed revenue change, whether it is an increase or a decrease, should be governed by four fundamental principles. Using the ROR as determined by the cost-of-service study (COSS), and incorporating all adjustments and allocation factors associated with the proposed revenue change, the Public Staff seeks to:

1. Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
2. Maintain a ±10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;
3. Move each customer class toward parity with the overall jurisdictional ROR; and
4. Minimize subsidization of customer classes by other customer classes.

Q. DID THE COMPANY ADHERE TO THESE PRINCIPLES IN ITS ASSIGNMENT OF ITS PROPOSED REVENUE INCREASE?

A. Witness Pirro acknowledges the Public Staff's traditional revenue assignment principles of maintaining RORs within a band of reasonableness, moving classes toward parity with the overall ROR, and reducing cross-subsidies. With respect to the first principle related to the percentage of the revenue increase, a review of Pirro Exhibit 2, Column "I" indicates that the revenue increase[3] (Column I of the exhibit excludes the impacts of the EDIT-2 rider) assigned to the lighting class is the only revenue assignment that does not comply with the first principle. Including the impact of the revenues associated with EDIT-2 rider (Column "M" in Pirro Exhibit 2), the lighting class continues to receive an increase of 12.5% which is significantly more than two percentage points above the total revenue increase of 6.2% assigned to the NC Retail jurisdiction.

A review of the RORs calculated by the Company in its filed Form E-1, Item 45C, (SCP) indicates that the assignment of the Company's proposed revenue increase does not comply with the second principle of maintaining a ±10% "band of reasonableness" for RORs for the general service, industrial, and lighting classes.

[3] Includes the impacts of various riders (Energy Efficiency Rider, Existing DSM Programs Cost Adjustment Rider, BPM Prospective Rider, BPM Tune-Up Rider, EDIT-1 Rider, Job Retention Recovery Rider, and REPS. Inclusion of these rider revenues is necessary to understand the impacts related to base revenues.

With respect to the third principle, the Company's assignment of the proposed increase does move each customer class closer to parity with the NC retail jurisdiction ROR.

With respect to the fourth principle of reducing subsidization, Witness Pirro did take subsidization into account in his calculations of revenue requirement by reducing the difference between class RORs and the overall jurisdictional ROR when assigning revenue to the customer classes.

Q. HOW DID YOU ASSIGN THE REVENUE REQUIREMENT RECOMMENDED BY THE PUBLIC STAFF TO NORTH CAROLINA RETAIL CUSTOMER CLASSES?

A. The Public Staff intends to update our recommended jurisdictional revenue requirement and file supplemental testimony to provide a final recommendation on our recommended revenue change. I will provide the Public Staff's assignment of our proposed revenue change at that time.

Q. SHOULD THE COMMISSION ORDER A REVENUE DECREASE IN THIS PROCEEDING, WHAT RECOMMENDATIONS DOES THE PUBLIC STAFF HAVE REGARDING THE ASSIGNMENT OF THE REVENUE DECREASE TO THE CUSTOMER CLASSES?

A. In the event of a revenue decrease, I believe it is appropriate to focus on addressing any disparities in the class RORs. In addressing disparities in RORs, any revenue decreases assigned to individual customer classes should be limited so that no other customer class sees an increase in its assigned revenue requirement simply to address a disparity in RORs. In other words, in the event of a revenue requirement decrease, no customer class should see an increase simply to bring the class ROR within 10% of the jurisdictional ROR.

RATE DESIGN

Q. PLEASE DISCUSS THE RELATIONSHIP BETWEEN A COSS AND RATE DESIGN.

A. Rate design should follow the same cost causation approach underlying the COSS, such that each customer class, or customer, is responsible for an appropriate share of the costs that are planned for and incurred in order to serve them. This includes both fixed and variable costs. However, strict adherence to this cost causation principle may not always be possible if doing so would result in "rate shock" for certain customers or customer classes. In addition, and depending on the COSS methodology utilized, cost responsibility results can vary significantly due to unusual events that occur in the test year. The COSS functionalizes costs, thus providing a basis from which to start rate design, but does not necessarily dictate the final rate design. Other considerations and objectives such as undue impacts on low usage customers must also be considered when developing rate design.

Q. DOES THE COMPANY'S RATE SCHEDULE PORTFOLIO ALIGN WITH ITS COSS IN THIS PROCEEDING?

A. No. As discussed by Company witness Hager and Public Staff witness McLawhorn, the Company continues to rely on its historical use of the summer coincident peak (SCP) COSS methodology in this proceeding. This is inconsistent with the winter peaking characteristics of the Company's overall system. DEC's existing rate schedule portfolio, however, remains oriented around summer peaking utility service.

Q. BRIEFLY DESCRIBE YOUR REVIEW OF THE COMPANY'S PROPOSAL FOR ITS RATE SCHEDULES.

A. Witness Pirro discussed the load research data, marginal cost data, and the relationships between seasons, on-peak, and off-peak hours, and system planning considerations that are identified in the Company's integrated resource plan that were reviewed and considered. However, the Company made very few modifications to any of its rate schedules other than to increase individual rate elements within each schedule to accomplish the revenue increase assigned to the rate class itself.

My review of Form E-1 Item 42 and the Company's responses to Public Staff discovery indicates the Company made a slight shift in the demand charges for Schedule RT to acknowledge the Company's movement toward being a winter peaking utility. In discovery, the Company also acknowledged a misalignment of seasons between Schedules RS and RT.

The Company also acknowledged that its costing and revenue models were not updated to reflect current pricing because the Company wanted to use its new AMI meters and data analytics to explore the potential for new rate designs.

Most notably the Company did not provide any discussion or proposals that would address issues related to rate designs that are being discussed in other dockets and proceedings that reflect the future of utility service. For example, there were no proposals for EVs, microgrids, energy storage, or DERs.

Q. PLEASE DISCUSS ELECTRIC VEHICLES IN MORE DETAIL.

A. The Public Staff's comments in the EV Pilot dockets criticized the Company for its lack of any proposal for specific rate designs that might inform the proposed EV pilots. If the Company is going to be responsive to the trends of EV adoption that are anticipated in the next few years, then new EV rate designs will need to be considered now.

I believe it is appropriate for the Company to begin working on new EV rate designs now, and to discuss those designs with stakeholders as they are considered and developed. Therefore, I recommend that the Commission require DEC to develop and propose EV rate designs as part of the larger rate design study recommended in my testimony.

Q. PLEASE DISCUSS THE STATUS OF THE ONGOING TOU PILOTS.

A. The Company continues to study the TOU pilots that were approved and implemented pursuant to Commission orders dated July 2, 9, and 29, 2019 in Docket No. E-7 Sub 1146. These pilots were initiated in October of 2019. Thus far, data indicates that the residential TOU pilots have been fully subscribed. The non-residential pilots have been less popular with approximately one-third of planned participants for the pilots subscribed.

The response by residential customers is promising. How these TOU rates affect system peaks or the extent they reduce peak demands, particularly winter peak demands remains to be seen. The Company should rigorously pursue an analysis of the reasons why the non-residential pilots are not fully subscribed. The Company will be filing periodic reports detailing the peak demand impacts, customer responses, and other observations resulting from the pilot programs.

Q. DO YOU HAVE ANY SPECIFIC COMMENTS OR RECOMMENDATIONS CONCERNING ANY OF THE COMPANY'S PROPOSED RATE SCHEDULES OR RIDERS?

A. Yes. Notwithstanding my earlier testimony highlighting the status quo nature of the Company's rate schedules, I am generally supportive of the few proposed changes to its rate schedules and service regulations as discussed by witnesses Pirro and Reed. Other than proposed changes to the lighting rate schedules, the Company did not propose substantial changes to the structure of its rate schedules in this proceeding. However, the Company has proposed changes to its lighting rate schedules, Rider MRM, and certain fees in its service regulations, that warrant further discussion.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO MAINTAIN THE BFCS AT CURRENT LEVELS.

A. The Company has not proposed any change in this proceeding to the BFCs in any of its rate schedules. Company Witness Pirro stated that DEC decided to maintain the current BFCs due to past concerns raised by low-income customer advocates. Instead, the Company proposes a stakeholder process to discuss opportunities to address low-income, fixed-income, and low-usage customer concerns.

Q. DOES THE PUBLIC STAFF AGREE WITH MAINTAINING BFCS AT CURRENT LEVELS?

A. The Public Staff does not object to the Company's proposal to leave BFCs at current levels for purposes of this proceeding. As discussed later in my testimony, the Public Staff supports convening a stakeholder process to address affordability issues, including the appropriate amount of the BFC.

Q. PLEASE DISCUSS THE CHANGES TO THE LIGHTING RATE SCHEDULES.

A. The Company is proposing three substantive changes in its lighting service. Those changes are: (1) proactive transition away from mercury vapor (MV) fixtures that would see most, if not all of its MV lights converted to light emitting diode (LED) fixtures by 2023; (2) reducing the transition fees associated with early transition of existing high pressure sodium (HPS) and metal halide (MH) fixtures to LED fixtures; and (3) removing the "inside municipal" designation in Schedule PL and merging it with other "existing pole" rates.

The Company continues to see a transition of HPS and MH lighting fixtures to LED. Customers express a preference for more efficient lighting options with better light quality. The evidence of this transition is apparent when looking at the billing units of the various lighting types in the Company's Form E-1, Item 42. This transition is expected to continue or even accelerate with the decrease in transition fees proposed in this case. The transition fees are intended to partially recover the cost of existing lighting assets that have not been fully depreciated. Recovering these costs from the customers seeking LED fixtures mitigates the impact to the remaining lighting class resulting from stranded lighting costs. In the test year, the Company collected approximately $800,000 in transition fees.

The Company is also proposing to eliminate the distinctions between inside and outside municipal rates in Schedule PL. As discussed by Company witness Reed, Schedule PL originated in the early 1990s, with rates that were supposedly differentiated using the rationale that it cost more to serve fixtures outside of municipal limits. My review of the history of Schedule PL has not been fruitful in providing any information that would justify the continuation of this distinction. As mentioned by Company witness Reed, the distinction has been less clear as municipal limits have greatly expanded in the last 30 years. My review of the billing analysis in Form E-1, Item 42 indicates that approximately 52,000 out of 3,000,000 non-floodlight fixtures are classified as “outside municipal limits.” This reclassification of fixtures could result in a 13% to 17% increase in rates if the Company’s proposed revenue requirement is approved.

I believe these changes in lighting services are reasonable and should be approved. Any new rates should be commensurate with the new revenue requirement approved by the Commission in this proceeding.

Q. PLEASE DISCUSS THE CHANGES PROPOSED FOR RIDER MRM (MANUALLY READ METER).

A. Witness Pirro did not propose any change to the fees associated with Rider MRM. He stated that these fees have been in effect for less than a year and that it was premature to adjust them at this time. Witness Pirro also testified that the costs of Rider MRM could justify an increase in the one-time setup fee from $150 to $230.80 and the recurring monthly fee from $11.75 to $14.05.

Rider MRM was approved by the Commission in 2018[4] in response to customer concerns surrounding exposure to radio frequency (RF) emissions and data privacy. The Rider MRM Order also provided a fee waiver process for customers providing certified medical documentation of their susceptibility to RF emissions.

The Public Staff inquired as to the current deployment of AMI and subscriptions to Rider MRM. For its North Carolina service territory, through June 2019, the Company has:

- Deployed 1.7 million residential AMI meters and 300,000 non-residential AMI meters
- Deployed 58,000 non-AMI residential meters and 21,000 non-AMI non-residential meters. None of the customers served by

[4] Order dated June 22, 2018 in Docket No. E-7 Sub 1115 (Sub 1115 Order).

these non-AMI meters were subscribed to Rider MRM. Since June 2019, all but 20,000 of these non-AMI meters have been exchanged with an AMI meter.

- Enrolled 884 residential and small general service customers in Rider MRM, with 663 successfully qualifying for the waiver of fees in Rider MRM.

The Sub 1115 Order required the Company to update the rates of Rider MRM in its next general rate case. In response, the Company provided confidential calculations of the rider fees, which I reviewed and compared to those originally filed with Sub 1115. Those calculations have been updated with new cost inputs related to this proceeding and new projections of Rider MRM participants. The updated inputs and the decrease in the number of likely participants result in a 53% increase in the one-time fee and a 20% increase in the monthly fee using the same methodology by which the original fees were calculated. My review suggests that these proposed fees are cost justified. However, the Public Staff is not recommending a change at this time.

The Public Staff believes that any costs associated with Rider MRM not recovered by the rider itself should be socialized and recovered from all customers. The current charges provide a reasonable hurdle to discourage a customer from opting out of AMI metering without a legitimate reason.

Q. WHAT HAS THE COMPANY DONE TO REFLECT THE USE OF AMI IN ITS CONNECTION FEES?

A. Customers will receive a benefit from the deployment of AMI meters in this case regarding connection and reconnection fees. The Company has requested approval to reduce its new connection and its reconnection fees. Witness Pirro proposes to decrease the connection charges from $24.18 to $10.51. He proposes to decrease the reconnection charges from 27.13 to $9.25 during normal business hours and to $10.58 for all other hours. These reductions are due to labor savings resulting from no longer having to dispatch Company personnel to the customer's location in order to perform connections and reconnections.[5]

I reviewed the Company's calculations of these proposed rates and I find them to be reasonable.

Q. HAS THE COMPANY UTILIZED AMI DATA TO DEVELOP NEW RATE DESIGNS OR INFORM THE EXISTING RATE DESIGNS?

A. No. The Company essentially completed its deployment of AMI meters in 2019. In the Sub 1146 proceeding, I testified on the extent

[5] See the November 15, 2019 order in Docket Nos. E-7, Sub 1210 and E-2, Sub 1214 granting partial waiver from Commission Rule R12-11(m)(2) and imposing limits on the requirements to have Company personnel on the customer's premise immediately before disconnection.

of the Company's AMI deployment at that time. My testimony highlighted the Company's commitment to exploring and developing new rate designs once smart meters were fully deployed and data from those meters became available. That time has arrived. The Company also should begin incorporating AMI data into its load research efforts supporting both rate design and integrated resource planning, thus providing a more detailed understanding of how the electric utility system is being used by all its users. As discussed below, I believe it is time for the Company to undertake a comprehensive rate design study.

COMPREHENSIVE RATE DESIGN STUDY

Q. WHAT IS YOUR OPINION REGARDING THE COMPANY'S DECISION IN THIS CASE TO RETAIN THE CURRENT RATE DESIGNS IN THIS PROCEEDING?

A. Company Witness Pirro's testimony explains the rate design approach used in this case. That approach effectively maintains the current rate designs of its rate schedule portfolio, with only minor modifications to the differential of on- and off-peak rates in the TOU schedules.

Q. HOW DOES THE PUBLIC STAFF PROPOSE TO MOVE TOWARD A NEW RATE DESIGN?

A. The Public Staff believes the Company should undertake a comprehensive rate design study prior to the filing of its next rate case to allow stakeholders the opportunity to participate in the discussion. The study should provide an analysis of each rate schedule to determine whether the schedule remains pertinent to current utility service, and should include whether the schedules should remain the same, be modified, or be replaced; the potential for new schedules to address the changes affecting utility service needs to be developed; and providing more rate design choices for customers.

Q. WHAT DOES A COMPREHENSIVE RATE DESIGN STUDY LOOK LIKE?

A. A comprehensive study needs to encompass the issues facing the utility of the future, particularly those issues that I have discussed previously in my testimony. The Company is already conducting a study of its cost-of-service. A study of rate designs should follow soon thereafter. Both are inextricably related. Rate designs should be rooted in a few broad principles that require rates to:

1. Be forward-looking and reflect long-run marginal costs.
2. Be focused on the usage components of service that are the most cost- and price-sensitive.
3. Be simple and understandable.

4. Recover system costs in proportion to how much electricity consumers use, and when they use it.
5. Give consumers appropriate information and the opportunity to respond to that information by adjusting their usage.
6. Where possible, be dynamic.[6]

These guiding principles must provide consumers and users of the electric system: (1) the ability to connect to the utility system for no more than the cost of connecting to the grid; (2) pay for utility service in proportion to how much they use the system; and (3) for consumers and users who supply power to the utility system, fair and just compensation for the energy they supply. Each of these principles should be reflected in smarter rates.

Q. ARE THERE ANY EXAMPLES OF UTILITY SERVICES THAT YOU CAN PROVIDE TO JUSTIFY THE NEED FOR A COMPREHENSIVE STUDY?

A. Yes. Net metering and other distributed generation resources, microgrids, energy storage, and EVs are prime examples of systems and uses that provide both benefits to the grid and impose costs on the utility. Net-metered customers have never fully accepted the

[6] "Smart Rate Design for a Smart Future", the Regulatory Assistance Project (RAP), at page 6.
https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

rationale behind the resetting of any banked energy credits, which occurred because of the rate structures applicable to net metered customers. Other larger distributed generation resources may not fully realize the value of the ancillary services they provide or the costs in terms of standby service the utility provides when their generation is not available. Microgrids typically act like traditional utility service, but their ability to island themselves when the surrounding grid is out of service imposes costs on the system in the form of added facilities needed to island and sustain the microgrid's customers. Energy storage has the potential to flip cost-of-service on its head by diminishing the influence of peak demand in cost-of-service and rate design. Electric vehicles have the potential to influence both the load shape of the utility on a system and on a locational basis, providing both load and capacity at times when the utility could use both.

Other examples include TOU rates that currently may not reflect the seasonal and hourly load shapes that represent the utility's cost-of-service. Current TOU rate designs also provide limited choice and opportunity for customers who may desire a demand-energy rate design or customers who desire an all-energy oriented TOU rate design. These characteristics of the Company's current TOU rate designs are in addition to the recently implemented dynamic pricing pilot programs. Those pilots do not address the on- and off-peak periods or the general structure of current TOU rate designs.

One final example addresses the apparent firmness of utility service. In other words, do customers want firm utility service (24 hours, 7 days a week), or do they want non-firm service (standby to any extent) that provides electric service when the customer-owned generation is not available for the customer's use? The full cost-of-service for each type of service is vastly different and not adequately provided for in the Company's portfolio of rate schedules.

Q. WHAT OTHER CONSIDERATIONS WOULD JUSTIFY A RATE STUDY?

A. There are several other considerations worth mentioning. First, the unbundling of average rates into generation, transmission, distribution, and customer component costs may be appropriate in order to address firm and non-firm utility service. Customers with distributed energy resources may not receive full service requirements from the utility, and unbundling could provide insight into the benefits these customers provide to the system as well as the costs to serve them. Second, revenue stability may require some form of decoupling of revenues from sales. Third, grid improvement costs, coal ash clean-up costs, and the transition to a more carbon-free generation portfolio are driving utility rates higher. Fourth, rate designs need to encourage the efficient use of the electric system and promote energy efficiency. Fifth, customers desire more, not less, information and the dynamic ability to receive and respond to that information.[7] Finally, it has been almost eight years since the merger of DEC and Duke Energy Progress, LLC, yet their rate design structures remain very different in many ways. Many of these differences are confusing, and seem illogical, to customers that receive service from both utilities. A rate study could assist in a transition to consolidation of the rate designs of the two utilities.

Q. WHAT TIMEFRAME DO YOU ENVISION FOR A RATE STUDY?

A. This study is no trivial matter. This will be a serious and lengthy undertaking and involve many stakeholders. However, the development of the current Schedule OPT resulted from a process that brought business and industry together to formulate a TOU rate design with broad support. This proposed rate study will likely require a significant amount of time to develop, as well as to implement. Any significant transition of this type, however, is likely to produce winners and losers. Thus, a gradual implementation would be necessary to minimize any adverse impacts.

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[7] "Rate Design – What do Consumers Want and Need?" Smart Energy Consumer Collaborative, September 2019.

https://smartenergycc.org/rate-design-what-do-consumers-want-and-need/

PREPAY SERVICE

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED PREPAID ADVANTAGE PROGRAM.

A. On August 2, 2019, the Company filed an application seeking approval of a Prepaid Advantage Program (Prepaid Program) in Docket No. E-7, Sub 1213 (Sub 1213) and waiver of certain Commission rules related to monthly bill format, payments, and disconnection. The Public Staff presented this matter for approval at the Commission's Staff Conference on November 12, 2019.

At Staff Conference, the Commission asked several questions of Company representatives about the Prepaid Program. The Commission also allowed Al Ripley, Director of the Consumer, Energy, and Housing Project for the North Carolina Justice Center (NCJC) to make a presentation on the Prepaid Program, recommending that the Commission not approve the Prepaid Program or alternatively approve the program but maintain the consumer protections provided by Commission rules.

Following Staff Conference, the Commission issued an order on November 20, 2019, in Sub 1213 consolidating DEC's Prepaid Advantage Program with its pending general rate case in Docket No. E-7, Sub 1214 (Sub 1214). I will provide the Public Staff's perspective on the Sub 1213 Application, as well as to the Commission's questions and concerns.

Q. PLEASE DESCRIBE THE COMPANY'S PREPAID PROGRAM APPLICATION.

A. The Prepaid Program provides residential customers with a voluntary option to pay for their electric utility service in advance of usage, thereby avoiding the need for a deposit, reconnection fees, and late fees. The Prepaid Program is similar to an existing prepayment program DEC offers in its South Carolina service territory.[8]

Participants of this voluntary program must have a smart meter and will have the ability to review daily usage information through a secure web portal accessible by a computer or smartphone with internet, as well as receive account notifications via phone, email or text message.

The Program will be available to new and existing customers. However, customers are not eligible for the Program if the customer takes service under a TOU rate schedule or net metering tariff, is enrolled in the Equal Payment Plan, has an active deferred payment

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[8] Public Service Commission of South Carolina Docket No. 2015-136-E, Duke Energy Carolinas, LLC's Prepaid Advantage South Carolina Learnings Report.

https://dms.psc.sc.gov/Attachments/Matter/b1f67636-0890-42e4-b33e-b5f4702d7814 arrangement exceeding $500, or is identified as a medical alert customer pursuant to Commission Rule R12-11(q)

To enroll, participants will be required to make an initial payment of at least $40. Participants with an outstanding balance when enrolled in the Prepaid Program will have 25% of any payments credited toward the unpaid balance until that balance is satisfied, After enrollment, participants can increase their account balances as frequently as they want.

The Prepaid Program is designed to provide participants with frequent notices regarding their account balance, including notifications prior to their account reaching $0.00 (a zero balance). Notifications will be given to participants 5, 3, and 1 days prior to reaching a zero balance. Once an account's prepaid balance reaches a zero balance, the customer will have until the next business day to make a payment to bring the balance above zero before the customer's service is remotely disconnected. Customers will be required to provide DEC with a notification channel preference such as text, email, or phone. This preferred notification channel would be used to communicate with customers and notify them of their account balances and usage.

To have service reconnected, the participant must pay any outstanding balance and make an additional payment towards future service. Service is reconnected remotely within approximately 15 minutes following payment after a disconnection. Payments can be made online through the program portal, over the phone, or in person.

Billing rates for service will be the same as those for traditional post-pay service (Schedule RS). However, rates for basic customer charges, taxes, and other per account or flat charges will be applied to the prepaid account on a daily pro-rata basis.

The Company also requested approval of waiver from several Commission rules in conjunction with Program approval for which it would be impossible or impractical to comply. Specifically, DEC has requested waiver of:

1. **R8-8 – Meter Readings and Bill Forms.** This Rule requires billings after, and on the basis of, regular meter readings;

2. **R8-20 (b), (c), and (d) – Discontinuance of Service for Violation of Rules or Nonpayment of Bills.** This Rule addresses the grounds for discontinuance of service. Subsection (b) requires at least 24 hours' written notice before disconnection. Subsection (c) describes the manner for delivering such notice. Similarly, subsection (d) allows a customer to pay a delinquent bill any time prior to disconnection;

3. **R8-44(4)(d) – Method of Adjustment for Rates Varying from Schedule or for Other Billing Errors.** This Rule addresses billing errors such as charging a customer more or less than the authorized rate. Subsection (4)(d) provides that a customer may repay an undercharge in equal installments for the number of billing periods during which undercharges occurred;

4. **R12-8 – Discontinuance of Service for Nonpayment.** This Rule requires written notice to customers at least five days before discontinuing service for nonpayment;

5. **R12-9(b), (c), and (d) – Uniform Billing Procedure.** The listed subsections of this Rule address billing dates, past due dates, and finance charges; and

6. **R12-11(a), (b), (f), (g), (h), (i), (l), (m), (n), and (p) – Disconnection of Residential Customer's Electric Service.** This Rule addresses the timing of payment for service after service has been rendered, and the discontinuance of electric service for nonpayment under the traditional billing method.

Q. PLEASE EXPLAIN YOUR INVESTIGATION OF THE COMPANY'S PREPAID PROGRAM APPLICATION.

A. I reviewed several documents related to prepaid electric utility service including the South Carolina Learnings Report. I reviewed the processes, mechanics, and the impact of fees the Company will employ to provide the Prepaid Program to customers. I further reviewed the requested waivers to Commission rules and how those waivers would affect customer interactions with the Company. Lastly, I reviewed the transcript from the Commission's November 12, 2019, Staff Conference to respond to Mr. Ripley's presentation and the Commission's questions.

Q. ARE THERE OTHER ELECTRIC PROVIDERS IN NORTH CAROLINA OFFERING PREPAID ELECTRIC SERVICE?

A. Yes. On June 25, 2019, the Commission approved a prepaid service program for New River Light and Power Company[9] that is very similar in terms of process, mechanics and waiver of Commission rules to DEC's Prepaid Program. In addition, 20 out of 26 North Carolina-based electric membership cooperatives provide a prepayment option for customers.

Q. DO YOU BELIEVE CUSTOMERS ARE INTERESTED IN HAVING A PREPAYMENT OPTION FOR THEIR ELECTRIC UTILITY SERVICE?

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[9] Docket No. E-34, Sub 49.

A. Yes. I have seen several studies that strongly suggest voluntary prepay utility service options are well received and preferred by all types of customers. The South Carolina Learnings Report provides evidence of customer acceptance of the South Carolina program. As DEC indicated in its Sub 1213 application, 50% of South Carolina participants ranked themselves as 'Completely Satisfied,' and 73% felt the Prepaid Advantage program had a positive effect on their overall satisfaction with the Company (Report at page 14). Other studies have drawn similar conclusions particularly, for younger customer segments.[10] [11] The Prepaid Program is a voluntary option and gives customers choice in how they pay their bills.

Q. ARE THERE ANY TRANSACTION FEES ASSOCIATED WITH THE PREPAID PROGRAM?

A. While there are no fees specifically for the Prepaid Program, transaction fees for payments that currently apply to postpay service will also apply to Program participants. DEC's application for the Prepaid Program included a request to waive the transaction fee for any transaction involving credit and debit cards or electronic checks for participants in the Prepaid Program. The Company has also

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[10] http://defgllc.com/publication/the-perfect-match-between-millennials-and-prepay-energy/

[11] http://defgllc.com/publication/not-so-fast-prepay-energy-and-seniors-55-in-the-utility-sector/

requested authority to waive these service fees for all customers in the Sub 1214 proceeding.

Q. DO YOU AGREE WITH DEC'S PROPOSAL TO SOCIALIZE THESE TRANSACTION FEES?

A. Yes. I agree the costs of transaction fees (those that are associated with processing credit cards, debit cards, and electronic checks) should be allocated to all customers. My position is based on my review of information I received from the Company in the course of this case. For 2018, 73% of payment transactions and 76% of revenues from residential customers come from electronic type payments (e.g., credit or debit card, electronic check, E-Bill, and SpeedPay). The remaining payments are either mail-in or walk-in transactions. Non-residential payment transactions are about half-electronic (48%) and half mail-in (52%). A comparison of the data for 2016 and 2017 is similar, with a definite trend toward electronic transactions. Other customer survey data strongly suggest a preference for transaction fee-free electronic payment options.

Q. WHAT ISSUES OR CONCERNS WERE RAISED BY MR. RIPLEY AT THE NOVEMBER 20, 2019, STAFF CONFERENCE?

A. Mr. Ripley of the NCJC stated that he opposed approval of the Prepaid Program for two basic reasons: (1) the rapid remote disconnection process and (2) the waiver of Commission rules that provide consumer protections for disconnections.

Q. DID THE PUBLIC STAFF CONSIDER THE CONCERNS THAT MR. RIPLEY RAISED AT THE NOVEMBER 20, 2019, STAFF CONFERENCE?

A. Yes. The first issue involves the disconnection process associated with the voluntary Prepaid Program. I believe this disconnection procedure proposed by the Company for prepaid accounts that reach zero balances is reasonable. As explained by the Company in its application, customers would receive periodic notices through the communication channel of their choice prior to their accounts reaching a zero balance. If an account reached a zero balance, the Company would inform the customer, and if the account balance was not brought back up above zero the customer would be disconnected until payment was received. In addition to the multiple notices received prior to disconnection, the actual disconnection would not occur until the next business day, and only under fair weather conditions. Extreme weather conditions and holidays would result in the postponement of disconnection, likely until the next fair weather business day.

The difference between the time a prepaid account reaches zero and the time of actual disconnection needs to be as small as possible to reduce the amount of energy sales that go uncompensated. Otherwise, the Prepaid Program runs a risk of increasing lost sales revenues that increase the Company's uncollectible expenses and ultimately paid for by all other customers. Commission rules regarding disconnection are not intended to prevent disconnection, but to provide a fair process that affords postpay customers every opportunity to pay their bill. The Prepaid Program disconnection process of providing multiple advanced notices, and then the process of disconnection only on fair weather business days, provides ample protections for those who voluntarily participate in the Prepaid Program.

The second issue raised by Mr. Ripley involves the waivers of the rules that are applicable to postpay accounts. These waivers provide a process of metering, billing, disconnection of service for nonpayment, and customer notice related to disconnection. These rules are not applicable to the Prepaid Program because participants voluntarily prepay for electric service. Postpay accounts receive utility service first and then a bill 30 days later. Customers may have an additional 30 to 90 days to pay delinquent bills. These procedures are not applicable to prepaid services.

In written comments submitted at Staff Conference, Mr. Ripley discussed several other points related to the customer notice process and consumer protections in other prepayment programs as highlighted by a National Association of State Utility Consumer Advocates (NASUCA) resolution. Mr. Ripley rightly mentions the inability of customers to communicate with DEC or receive customer notice when phone or internet service is not available to the prepaid participant. This concern could affect all utility services, whether prepaid or postpaid. Customers participating in this voluntary program, as well as DEC, bear responsibility for maintaining open communication channels. It would be appropriate to require DEC to confirm whether Prepaid Program participants actually receive the notifications when enrolling in the Program.

With respect to the NASUCA resolution, many of the attributes for a prepayment program are incorporated into the design and implementation of DEC's Prepaid Program. Specifically, all of the following protections listed in the NASUCA resolution are included in the Prepaid Program:

- Grace period between a zero balance and disconnection;
- Certain customer segments are ineligible due to medical conditions;
- Program is voluntary;
- Participants avoid the need for security deposits;
- Participants can increase their account balances anytime;
- Participants can return to postpaid service at any time, subject to the requirements of a security deposit and other costs associated with postpaid accounts; and
- Prepayments are immediately posted to customer's account. However, manual payments may take longer.

Q. SHOULD THE COMMISSION'S ORDER IN DOCKET NOS. E-7, SUB 1210 REGARDING WAIVER OF COMMISSION RULE R12-11(M)(2) APPLY TO THE PREPAID PROGRAM?

A. In part. In Docket Nos. E-7, Sub 1210, DEC requested relief from personally visiting customers' premises prior to disconnection of postpaid service as required under Commission Rule R8-12. The Commission's Order dated November 15, 2019, granted the waiver but required six conditions for the waiver. Those conditions are:

1. No disconnection before 3 p.m. to allow affected customers as much time as possible to make the necessary payments to restore service;
2. The full requirements of Rule R12-11(m)(2) would still apply to customers that do not have email, text messaging, or phone service;
3. That personal visits would be required per R12-11(m)(2), if there is any indication that the Company could not confirm that its communications with the customer via email, text, or phone were successfully received;
4. That for months November through March, any email, text, or phone communications regarding disconnections should include the information required by Rule R12-11(l)(6).
5. That the Company makes all reasonable efforts to have on file a third party designee, selected by the customer, who will

receive any notice of termination in addition to the customer; and

6. That the limited waiver to Rule R12-11(m)(2) would expire on June 30, 2021, unless otherwise extended by the Commission.

Conditions 1, 5, and 6 should be applied to the Prepaid Program. As mentioned previously in my testimony, the ability to quickly and remotely disconnect customers is an essential function of the Program.

Condition 1 addresses the disconnection timing and should apply to the Prepaid Program. The Company should revise the Prepaid Program to delay disconnections until after 3 p.m.

Conditions 2 and 3 should not apply to the voluntary Prepaid Program. As I testified earlier, DEC should confirm the ability of Prepaid Program participants to receive communications from the Company upon enrollment. Customers not able to receive notifications from the Prepaid Program should not be eligible for the Program.

Condition 4 is addressed by the Company's proposal to only disconnect on fair weather business days, or alternatively not enroll the customers described in Rule R12-11 (l)(6).

Condition 5 should apply to the Prepaid Program and be addressed when customers sign up for the Prepay Program.

Condition 6 should apply to the Prepaid Program. The Prepaid Program should be limited to the same time period as the limited waiver of Commission Rule R8-12. The Public Staff is also requesting periodic reporting of the Prepaid Program, which could assist the Commission in seeing how the waiver has impacted both prepaid and postpaid utility service.

Q. WHAT REPORTING REQUIREMENTS SHOULD APPLY TO THE PREPAID PROGRAM?

A. The Public Staff believes it is appropriate to require DEC to submit quarterly reports on the performance of the Prepaid Program by calendar month. The Public Staff will work with the Company to refine the information needed, but believes such reporting should include at least the following items:

- Number of participants enrolled on the last day of each month;
- Number of participants that withdraw from the Program and return to standard arrears billing;
- Average number of transactions observed per participant, distinguished by the method of payment used;
- A distribution of payment amounts (from least to most), and the average amount added to the account per transaction;
- A distribution of disconnections per participant;
- Number of participants with more than one disconnection in a 90-day period;

- Total number of disconnections;
- Average customer balance at time of disconnection; and,
- Average time from disconnection to reconnection.

Q. WERE THERE PUBLIC WITNESSES IN THIS CASE THAT INFORMED YOUR DECISION TO SUPPORT THE PREPAID PROGRAM?

A. Yes. I would encourage the Commission to review the testimony of public witness Ms. Peggy Wilson, who testified at the Sub 1214 public hearing in Graham, North Carolina on January 29, 2020. She testified about the struggles she had paying bills and sometimes balancing housing and utility bills with food bills. She also testified about making two payment arrangements to "rearrange my bills." She stated that Duke required another deposit because of the two payment arrangements within a 12-month period. In response to a question posed by Commissioner Hughes about the deposit, Ms. Wilson stated she was required to pay a deposit of "over $300." She had apparently paid a previous deposit. She concluded by stating that this deposit "took food out of my family's mouth." Her ability to sustain utility service is adversely impacted by the current regulatory requirements and structure associated with postpaid accounts.

While prepaid service is not a good fit for everyone, it does represent positive movement toward providing choice to customers in how they pay for utility service. AMI is what makes many of these options possible.

Q. DO YOU RECOMMEND APPROVAL OF THE PREPAID PROGRAM?

A. I recommend that the Commission approve DEC's request for the Prepaid Program subject to conditions 1, 5, and 6 as noted above of the Commission's Order in Docket Nos. E-7, Sub 1210 and E-2, Sub 1214, and the Public Staff's proposed reporting requirements.

AFFORDABILITY

Q. PLEASE DISCUSS THE COMMISSION'S ORDER DIRECTING THE PUBLIC STAFF TO FILE TESTIMONY.

A. The Commission's January 22, 2020 Order directed the Public Staff to "investigate DEC's analysis of affordability of electricity within its service territory as well as programs available to DEC's customers that address affordability with a particular focus on residential energy customers." In the Order, the Commission directed the Public Staff to address the following issues:

1. An overview of Lifeline Rates and whether this approach would be appropriate for North Carolina;

2. The applicability, design, and effectiveness of the Company's Supplemental Security Income (SSI)12 discount;
3. A comparison of the SSI discount to other tariffs available to customers that address affordability issues;
4. An overview of similar affordability tariffs or plans available by the other affiliates of DEC; and
5. The merits of using a "minimum bill" concept in lieu of a fixed customer charge.

Q. DOES THE COMPANY'S APPLICATION FOR A GENERAL RATE CASE ADDRESS ANY OF THESE REQUESTS?

A. No, it does not specifically address these requests. Company witness DeMay noted in his testimony that the Company is committed to helping customers who struggle with financial hardships. He cited several energy efficiency and philanthropic programs that provide assistance to help customers with their energy bills and offered to do more for those most in need. Witness DeMay also explained the Company's proposal to keep BFCs at current levels despite the Company having a cost-of-service justification for higher BFCs. He outlined the Company's proposal to engage interested stakeholders to discuss ways and opportunities to assist low-income customers in the Company's rate design such as low-

[12] https://www.ssa.gov/ssi/

income bill credits, bill round-up programs, and modifications to the SSI discount. He concluded by stating that a stakeholder process was necessary to adequately consider those opportunities.

Q. DID WITNESS DEMAY OFFER ANY OTHER SUGGESTIONS FOR HOW TO HELP LOW-INCOME CUSTOMERS?

A. Witness DeMay stated that the Company's application was developed using a lower Return on Equity (ROE) (10.3%), rather than the 10.5% ROE recommended by Company Witness Hevert. As discussed in the testimony of witness Woolridge, the Public Staff does not agree with the basis of Witness Hevert's ROE. The Public Staff also believes the Company's request for a lower ROE does not provide targeted rate relief for low-income customers for two reasons. First, it is virtually impossible to gauge **the** significance of the offer in terms of a reduced or forgone revenue requirement. Second, while a lower ROE obviously accrues to the benefit of all ratepayers, it is not targeted specifically to low-income customers.

The ROE is one of the most contentious issues of any rate proceeding, often litigated by having witnesses espouse various methods, calculations, interpretations, and findings to justify their respective positions. The parties never agree on the appropriate level of ROE, but sometimes reach settlement on the ROE, which may, or may not, be accepted by the Commission. In other words, there is never any certainty in what the ROE should be until the

Commission issues its order in the rate case. Given this contentiousness, it is impossible to benchmark the significance and amount of revenue the Company forgoes with a reduction of 20 basis points in an ROE. By applying an across-the-board reduction in ROE, all customers would see the benefit, not just low-income customers. The Public Staff believes it is more appropriate to resolve the ROE in the rate case by letting the Commission rule on the ROE (via settlement of the parties or otherwise), and then look for other more targeted ways and opportunities to mitigate rate impacts for low-income customers.

If the Company wants to make an effort to address affordability, the Public Staff believes there is an opportunity for shareholders of the Company to forego the revenues associated with the reduction in ROE proposed by Mr. DeMay and for DEC to use those funds to support other assistance programs or mitigate the possible revenue impacts associated with any proposal arising from the stakeholder process. If any new low-income program results in other customers paying a slightly higher rate to recover costs associated with any low-income programs, shareholders should participate in a similar manner.

Lifeline Rates

Q. WHAT ARE LIFELINE RATES?

A. I researched the term "lifeline rate" and discovered several definitions pertinent to the discussion on affordability. Below is a sampling of definitions I found:

1. Repealed Section 114 of PURPA[13] effectively allowed states to approve rates for residential customers that were lower than standard rates, without defining what the state authorities could do about implementing rates that were lower than the "standard rates" also defined by Section 111(d)(1) of PURPA (cost-of-service based rates).[14]
2. House Bill H.R. 6009 introduced in the 1977-78 Congress.[15] "Lifeline electric rates" - Requires that electric utility rate charges for subsistence quantities of electric energy to residential consumers not exceed the lowest rate charged to any other electric consumer. Requires the use of graduated rate structures for consumption of electric energy in amounts above subsistence quantities.

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[13] Floyd Exhibit No. 1, Public Utility Regulatory Policies Act of 1978. Section 114 was repealed in 2016. https://uscode.house.gov/view.xhtml?req=(title:15%20section:2624%20edition:prelim)

[14] "COST OF SERVICE.—Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the cost of providing electric service to such class, as determined under section 115(a)."

[15] https://www.congress.gov/bill/95th-congress/house-bill/6009?s=1&r=66

3. A report prepared for the Hydro Quebec Distribution Company.[16] “Lifeline rate:” A rate structure under which an initial block of consumption is priced lower than subsequent and higher blocks of consumption. A Lifeline rate may or may not be priced “below cost.”

This research suggests that “lifeline” rates are effectively inclining block rates. This type of rate structure provides a lower price for the initial usage than the next block of usage. The premise is that if a customer were a low-usage customer, the impact of increasing rates would be mitigated by having the initial block of usage priced lower. The concept of lifeline rates appears to have been conceived in the late 1970s in response to the oil crisis of the early 1970s.

The Public Staff does not generally support inclining block rate structures, because they are not cost-based. The first kilowatt-hour of use is typically more costly to produce than the next, a function of the fixed costs of utility service. Inclining block rates shift the recovery of revenues from the initial block to higher kWh blocks. By doing so, customers who buy less kWhs are not contributing an appropriate amount toward the recovery of fixed utility costs. This

[16] “INVERTED BLOCK TARIFFS AND UNIVERSAL LIFELINE RATES: Their Use and Usability for Delivering Low-Income Electric Rate Relief,” Roger Colton. Fisher, Sheehan & Colton. February 2008

http://www.fsconline.com/downloads/Papers/2008%2002%20Hydro_Quebec_Lifeline-Final.pdf reality exacerbates the need for future rate cases and fails to address the real cost causation of electric utility service. The shift in revenue recovery from low use customers to high use customers could also adversely affect low-income customers that are not low usage customers.

SSI Discount

Q. WHAT DID THE COMPANY PROPOSE FOR THE SSI DISCOUNT?

A. The Company did not propose any change in this proceeding to the current SSI discount other than to increase the rate and maximum amount of the discount commensurate with the requested revenue increase as has been done in prior general rate cases. The structure and eligibility of the SSI discount remain unchanged.

Q. PLEASE PROVIDE SOME BACKGROUND FOR THE SSI DISCOUNT.

A. I have reviewed several past orders and filings regarding the SSI Rates. Based on my research, the SSI rate was originally approved on August 31, 1978 in Docket No. E-7, Sub 237 (Sub 237 Order). The Sub 237 Order identified SSI customers as customers who were "relatively price-inelastic, blind, disabled, or aged receiving SSI from the Social Security Administration. The SSI discount was established so that the Commission could collect data in a comprehensive study of "lifeline type rate schedules as mandated by the 1977 North Carolina General Assembly."[17]

The Commission's proceeding in Docket No. E-100 Sub 43 (Sub 43 Proceeding) was an effort to implement Section 114 of PURPA. The Sub 43 Proceeding included an RTI Study[18] that investigated the SSI discount. Around this time in the early 1980s, the Company filed another general rate case (Docket No. E-7, Sub 338). The Commission brought the SSI discount/lifeline rate issue into the Sub 338 case.

The Order Granting Partial Rate Increase issued November 1, 1982 (Sub 338 Order) provides a good summary of the SSI issue and the Commission's consideration and decision.[19] An excerpt of testimony from the Sub 338 Order provides a good summary of the SSI issue.

> "During the course of the hearing in Docket No. E-7, Sub 338, witness Desvousges of RTI testified that: (1) SSI recipients have lower electricity usage, lower appliance saturation, smaller homes, and smaller family size than non-SSI customers; (2) SSI recipients have a lower percentage of use during single peak hours (i.e., higher load factor) but greater percentage of use during total on-peak hours than non-SSI customers; and (3) the difference in usage patterns between SSI recipients and non-SSI customers does not create a difference in cost.

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[17] See Finding of Fact 25 in the Sub 237 Order.

[18] Floyd Exhibit No. 2, "An Evaluation of a Lifeline Rate Alternative: The Supplemental Security Income Rate," William H. Desvousges, C. Andrew Clayton, Dale P. Lifson. RTI Economics, September 1981.

[19] See the evidence and conclusions associated with Finding of Fact 29 in the Sub 338 Order.

Witness Stutz, representing the intervenor Lillia Brooks, et al., testified that: (1) the higher load factor at single peak hours and the lower appliance saturation of SSI recipients strengthens the hypothesis that they may be cheaper to serve than non-SSI customers, but that the hypothesis has not yet been proven either way; (2) the RTI conclusion regarding the percentage of usage by SSI recipients during single peak hours versus total on-peak hours is not valid, because it is based on a marginal cost approach not used anywhere else in Duke cost allocations; and (3) the RTI conclusion regarding cost differences between SSI recipients and non-SSI customers is not valid because no cost allocation study was performed using the same embedded cost methods which are used to determine the costs for non-SSI customers.

Witness Stutz contended that further study was needed of the elasticity of demand between SSI recipients and non-SSI customers and that a fully distributed cost of service study was needed in which SSI recipients and non-SSI customers are identified as separate customer groups. Witness Desvousges contended that such elasticity of demand study and such fully distributed cost of service study were not a part of the RTI contract. Witness Stutz recommended that, even though approximately $100,000 had already been spent studying the cost to serve approximately 8,000 SSI recipients on the Duke system, further studies should be made at further expense in order to complete the analysis properly.

Witness Stutz conceded that data is not now available in the form necessary to perform the embedded cost allocation study he recommended, and that, even if it were, the cost allocation method currently used (i.e., summer coincident peak method) is subject to change. Therefore, he recommended that the SSI rate be retained until further studies are complete and that further studies be made utilizing the same cost allocation method used to determine costs for SSI recipients and for non-SSI customers.

The Commission makes the observation that, while the RTI study shows SSI recipients to have a higher percentage of total use during on-peak hours than non-SSI customers, it does not determine if the same thing holds true for those kWh subject to the SSI discount (i.e.,

> the first 350 kWh per month). The Commission also makes the observation that determination of on-Peak costs versus off-peak costs need not be based on marginal cost but can be based on embedded cost as well.
>
> Based on the testimony and evidence presented herein, the Panel is of the opinion that the studies to determine a cost justification for the SSI rate are inconclusive. An additional concern is the expense which must be incurred for further studies in view of the limited number of SSI recipients who are the object of study. There may be many more low income, low usage customers who are not HI recipients but have similar usage characteristics, and further study should perhaps include them.
>
> The Commission concludes that the SSI rate should be retained for purposes of this proceeding and that final determination of the question of and the scope of studies should be resolved by the Commission in Docket No. E-100, Sub 43."
>
> ***Sub 338 Order Beginning at page 139.***

General rate case orders that followed the Sub 237 Order and Sub 338 Order, including the more contemporary rate case orders for the Company since 2007 (Subs 828, 909, 989, 1026, and 1146), do not provide much insight on the SSI discount. I do note that Company witness Barbara Yarbrough addressed the history of the SSI discount in her rebuttal testimony in the Sub 909 case. However, the Public Staff and Company settled many issues in that case and the SSI discount was not specifically addressed in the approved settlement agreement or final order.

Q. HAVE YOU REVIEWED THE RTI ECONOMICS STUDY THAT WAS PART OF THE DOCKET NOS. E-100, SUB 43 AND E-7, SUB 338 PROCEEDINGS?

A. Yes.

Q. IS THERE ANY PERTINENT INFORMATION FROM THE RTI STUDY THAT IS APPLICABLE TO UTILITY SERVICE IN 2020?

A. The RTI Study is almost 40 years old. Utility service in the late 1970s and early 1980s is vastly different than it is today. The findings of the RTI Study are informative, however. The RTI Study indicated a difference in the energy consumption behavior of SSI customers and non-SSI customers. SSI customers used about half the energy that non-SSI customers used. The differences were greater in winter peak periods. Load factors and usage profiles were different. Also, electric appliance use was lower for SSI customers than non-SSI customers. SSI customers tended to have smaller, less expensive homes and smaller families. Each of these differences certainly suggests a difference in the cost to serve each group.

I reviewed another study that was published by the US Department of Energy (DOE Lifeline Study)[20] that studied other similar programs around the nation. It was clear to me that the data from the late 1970s and early 1980s may not be appropriate for consideration today. One very apparent example is average energy consumption. In the early 1980s the average was approximately 500 kWh per

[20] "Lifeline Electric Rates and Alternative Approaches to the Problems of Low-Income Ratepayers – Ten Case Studies of Rejected Programs," July 1980. https://www.osti.gov/servlets/purl/5699224

month. This is consistent with the RTI Study (Table 4-8). The Company's billing analysis in this proceeding calculates an average usage for residential customers of 1,100 kWh per month. I believe this suggests a very different usage and cost pattern from the ones observed in the RTI Study and DOE Lifeline Report.

I also reviewed a 2010 study from the Edison Foundation21 that concluded low-income customers did have a flatter load profile (higher load factor) and that they were responsive to dynamic pricing signals. This study is contemporaneous and may provide some useful information regarding load shapes of low-income customers, costs, rate designs, participation in TOU rates, demand response, and adoption of energy efficiency measures.

Q. IS THERE ANY DATA FROM THIS PROCEEDING TO SUGGEST ANY DIFFERENCES IN USAGE BETWEEN SSI CUSTOMERS AND NON-SSI CUSTOMERS?

A. No. Data from the billing analysis is not detailed enough to observe differences, nor has the Company investigated to see if the original difference still exists. I believe that using SSI to determine eligibility for a rate discount may be too narrowly focused. The Company has approximately 9,900 residential customers enrolled in the SSI rate discount program. This represents approximately 0.9% of the total

[21] https://www.edisonfoundation.net/IEE/Documents/IEE_LowIncomeDynamicPricing_0910.pdf

number of residential customers). However, the Company has not tracked differences in usage between SSI and non-SSI customers. Other data for North Carolina suggests that the SSI-eligible population is approximately 2.2% of the total population (228,906 / 10,383,620).[22]

Q. HAS THE COMPANY STUDIED THE EFFECTIVENESS OF THE SSI DISCOUNT?

A. No. The Company has not conducted a study on the effectiveness of the SSI discount. DEC has not undertaken any meaningful analysis to investigate the impact of this case on low-income customers or affordability issues in general. In addition, there has been no significant push over the last forty years to study the effectiveness of the SSI discount from the General Assembly or other parties, including the Public Staff. There was also some uncertainty about the effectiveness of the discount even in the early proceedings that led up to the SSI discount. Without a doubt, though, the time has arrived for an evaluation of the SSI discount, or alternatively other means of assisting low-income customers.

Q. DO YOU HAVE ANY RECOMMENDATIONS CONCERNING THE SSI DISCOUNT?

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[22] https://www.census.gov/quickfacts/NC
https://www.ssa.gov/policy/docs/statcomps/ssi_sc/2018/nc.pdf

A. Yes. This issue is ripe for discussion in the stakeholder process recommended by DEC witness DeMay and as outlined in my testimony. The stakeholder process is the best place to evaluate the discount in the context of providing new rate structures to help all low-income customers. The minimal SSI discount and the narrow eligibility requirements are likely causing the effectiveness of the discount to be insignificant. The evidence is inconclusive from the Company's billing analysis. For example, under the Company's present rates, $262,000 of the $2 billion of annual revenue from energy sales for Schedules RS and RE represents the amount of the discount received by the 9,900 SSI customers, or approximately $26 per SSI customer per year.[23]

Affordability Tariffs by other Duke Energy Affiliates

Q. WHAT OTHER RATE PLANS THAT ADDRESS AFFORDABILITY ARE AVAILABLE IN OTHER JURISDICTIONS WHERE DUKE ENERGY PROVIDES ELECTRIC SERVICE?

A. The only rate plan addressing affordability offered by a Duke Energy Company affiliate in another jurisdiction is the Rate RSLI, or Residential Service - Low Income, offered by Duke Energy Ohio. Limited to 10,000 customers, the program offers customers that are at or below 200% of the Federal poverty level a $4 per month

[23] Calculation was developed from SSI sales data and present rates on tabs "NC-RS" and "NC-RE" of Form E-1, Item 42 billing analysis.

discount on the monthly customer charge. The per kWh energy charge is not provided a discount.

Other Affordability Tariffs Around the Country

Q. HOW DOES THE COMPANY'S SSI DISCOUNT COMPARE TO OTHER DISCOUNT OR RATE PROGRAMS AROUND THE COUNTRY?

A. Several investor-owned electric utilities offer various types of low-income assistance programs. Floyd Exhibit No. 3 provides a list of the ones I reviewed and the web links to those programs. The most prevalent model seems to be a bill discount that either applies a percentage reduction to the total bill or a flat dollar discount. The most likely qualification factor is one that is based on household income as a percentage of the federal poverty guidelines, or age, or if the customer is already enrolled in another governmental assistance program, or some combination of the three.

Minimum Bill Concept

Q. PLEASE DISCUSS THE MINIMUM BILL CONCEPT.

A. The "minimum bill" concept guarantees the utility a minimum annual revenue level from each customer even if the customer consumes no energy.[24] It provides some stability in utility revenues that could

[24] Floyd Exhibit No. 4. - "Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches to Recovering Basic Distribution Costs," (RAP Report), November 13, 2014. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-electricutilityresidentialcustomerchargesminimumbills-2014-nov.pdf

mitigate future requests to increase rates. Some minimum bill concepts also include a fixed amount of energy sales. In other words, customers would be charged for a fixed amount of energy regardless of actual energy consumption.

Many of the Company's non-residential rate schedules already include a minimum bill provision. For example, Schedules SGS and LGS include the following language (from Exhibit B of the Application):

> "The minimum bill shall be the bill calculated on the Rate above including the Basic Facilities Charge, Demand Charge and Energy Charge, but the bill shall not be less than the amount determined as shown below according to the type of minimum selected by the Company:
>
> $2.16 per kW per month of Contract Demand
>
> If the Customer's measured demand exceeds the Contract Demand, the Company may, at any time, establish the minimum based on the maximum integrated demand in the previous 12 months including the month for which the bill is rendered, instead of the Contract Demand.
>
> Annual
>
> $44.34 per kW per year of Contract Demand
>
> The Company may choose this option when the Customer's service is seasonal or erratic, or it may offer the Customer a monthly minimum option.
>
> Unless otherwise specified in the contract, the billing procedure for annual minimums will be as follows:
>
> For each month of the contract year when energy is used, a monthly bill will be calculated on the Rate Above. For each month of the contract year when no energy is used, no monthly amount will be billed. The bill for the last month of the contract year will be determined as follows:

> -- If the total of the charges for 12 months exceeds the annual minimum, the last bill of the contract year will include only the charges for that month.
>
> -- If the total of the charges for 12 months is less than the annual minimum, the last bill of the contract year will include an amount necessary to satisfy the annual minimum.

According to the billing analysis in Form E-1, Item 42, Schedule SGS had 2,941 bills out of approximately 2.7 million that were impacted by the minimum bill provision (0.1%). Schedule LGS had one bill out of 110,000 bills impacted by the minimum bill. None of the Schedule OPT customers were impacted by the minimum bill provision.

Q. PLEASE DISCUSS THE MERITS OF USING THE MINIMUM BILL CONCEPT IN LIEU OF A FIXED CUSTOMER CHARGE.

A. Minimum bills are designed to recover a portion of fixed costs to serve the customer. As discussed above, a minimum bill amount would include at least the amount of the BFC, or fixed customer charge, but could include additional costs as well. The Public Staff has generally been supportive of BFCs that are based on cost causation principles. However, other stakeholders have raised affordability concerns over the impact of higher fixed charges.

The RAP Report provides a good comparison of the impacts under three pricing scenarios (high and low customer charges and a minimum bill approach). The RAP Report illustrates how the customer charge and energy charge work together to produce the revenues. A low customer charge requires a higher energy charge to recover the same revenue. The minimum bill approach only impacts the low usage customer, but eventually produces similar revenues as the combined customer and energy charges do. The RAP Report goes on to discuss the elasticity of electric rates and usage and concludes that any approach using a high fixed charge approach is not popular with customers.

Q. WOULD A MINIMUM BILL APPROACH REPLACE THE BFC?

A. Not necessarily. An appropriate minimum bill provision applicable to residential customers would need to be designed in a manner that ensures all customers are contributing toward the fixed cost to serve them. It would have some impact on the amount of the other charges used to produce revenue because the minimum bill rather than the combination of customer, demand, and energy charges would produce more of the total revenue. However, such a provision should not be a substitute for appropriately pricing the basic customer charges.

Q. WHAT IS THE IMPACT OF IMPLEMENTING A RATE DESIGN THAT DOES NOT RECOVER THE FIXED COSTS TO SERVE THE CUSTOMER?

A. Cost causation requires that the combined rate elements in a rate schedule (BFC, demand, and energy charge) be appropriately designed to recover the fixed costs to serve the customer. When one element is under priced, the remaining elements have to support the recovery of fixed costs. Any rate schedule that fails to recover the fixed costs associated with the customers taking service under that schedule will shift the cost to serve those customers to other customers on other rate schedules.

Q. PLEASE DISCUSS THE PUBLIC STAFF'S VIEW OF AFFORDABILITY ISSUES AND THE COMPANY'S PROPOSED STAKEHOLDER PROCESS TO ADDRESS AFFORDABILITY.

A. Affordability is an important issue for all customers, residential and non-residential alike. Residential customers face difficult challenges balancing bills each month. Non-residential customers face similar challenges deciding where and how to conduct business and whether to invest in infrastructure and jobs.

The Public Staff continues to fundamentally believe that rate design must first be based on cost-causation principles. After cost-based rates are determined, public policy may provide further guidance in designing final rates. The Public Staff believes the stakeholder process is the most appropriate venue to have this conversation. I believe the January 2020 Order provides the outline of issues that should be discussed in this process. However, it is also incumbent upon the Commission to give the parties some guidance on affordability issues. The Public Staff recommends the following parameters for a stakeholder process:

1. Set a timeline for the process, including a deadline for the filing of recommendations to the Commission. I believe a maximum of one year is reasonable.
2. Investigate how "affordability" has changed over time, and seek to define it for purposes of utility service today.
3. Investigate the success of existing rates, assistance, and energy efficiency programs to address affordability.
4. Analyze the data related to load, cost, and revenue profiles of low-income customers and the residential class in general, cost-causation, impact to cost-of-service, potential for subsidization, impact on revenues and rates for all customers, program eligibility, extent of assistance needed to be meaningful, definition of a "successful program," etc..
5. Require periodic reporting to the Commission on the status of the process.

Any rate discount for low-income customers will shift revenue recovery to other customers in the form of slightly higher rates. This shift or subsidization must be thoroughly understood in terms of the dollars to be shifted and the effect on rates paid by other customers. I am also concerned that this shift could adversely impact those customers who would be on the edge of <u>NOT</u> qualifying for any program (i.e., just above the threshold of household income that might qualify the customer).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

JACK L. FLOYD

I am a graduate of North Carolina State University with a Bachelor of Science Degree in Chemical Engineering. I am licensed in North Carolina as a Professional Engineer. I have more than 17 years of experience in the water and wastewater treatment field, nine of which have been with the Public Staff's Water Division. In addition, I have been with the Electric Division for almost 16 years.

Prior to my employment with the Public Staff, I was employed by the North Carolina Department of Natural Resources, Division of Water Quality as an Environmental Engineer. In that capacity, I performed various tasks associated with environmental regulation of water and wastewater systems, including the drafting of regulations and general statutes.

In my capacity with the Public Staff's Water Division, I investigated the operations of regulated water and sewer utility companies and prepared testimony and reports related to those investigations.

Currently, my duties with the Public Staff include evaluating the operation of regulated electric utilities, including rate design, cost-of-service, and demand side management and energy efficiency resources. My duties also

Include assisting in the preparation of reports to the Commission; preparing testimony regarding my investigation activities; reviewing Integrated Resource Plans; and making recommendations to the Commission concerning the level of service for electric utilities.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUBS 1213 AND 1214

SUPPLEMENTAL TESTIMONY OF JACK L. FLOYD
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

MARCH 25, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jack L. Floyd. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an Engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THESE PROCEEDINGS?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to present the Public Staff's recommended distribution of revenues based on the results of the summer coincident peak (SCP), winter coincident peak (WCP), and summer/winter coincident peak and average (SWPA) cost-of-service methodologies. My calculations are based on the request of Duke Energy Carolinas, LLC (DEC or the Company) for a base revenue increase and an Excess Deferred Income Tax (EDIT) rider, and the Public Staff's adjustments to that request.

The Public Staff's recommended base revenue increase of $126,710,000[1] and an EDIT credit of $272,633,000[2] are provided in the supplemental testimony and exhibits of Public Staff witness Boswell. I have used this information to assign the revenues and credits to the customer classes.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. My testimony includes four exhibits. Floyd Exhibit 1 illustrates the rates of return (ROR) on rate base, the percentage change in base revenues, and the impact of the EDIT credit rider for each cost-of-service methodology. Floyd Exhibits 2, 3, and 4 provide an illustration of the base revenue and EDIT-2 credit assignments under an "equal rate of return" scenario and an "equal percentage increase" scenario for each cost-of-service methodology.

Q. BRIEFLY EXPLAIN HOW YOU DISTRIBUTED THE BASE REVENUE CHANGE.

A. I used the "per books" versions of the Company's cost-of-service studies for each methodology to develop a distribution framework that incorporates the overall base revenues, expenses, net income, and rate base for the test year. Using this framework, I then took Public Staff witness Boswell's adjusted present and proposed revenues, expenses, and rate base to develop the Public Staff's recommended base revenue change. The

[1] Line 49, Boswell Supplemental and Stipulation Exhibit 1, Schedule 1.

[2] Line 55, Boswell Supplemental and Stipulation Exhibit 1, Schedule 1.

assignment of the Public Staff's recommended revenue change is developed using the four basic revenue assignment principles I outlined in my direct testimony. Those principles are:

1. Any revenue increase assigned to any customer class is limited to no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
2. Class RORs are maintained within a band of reasonableness of ± 10% relative to the overall NC retail ROR;
3. All class RORs move closer to parity with the NC retail ROR; and
4. Subsidization among the customer classes is minimized.

The results of my work are provided in my supplemental exhibits. The Public Staff's proposed assignment adheres to each of these principles.

Q. HOW DID YOU ASSIGN THE PUBLIC STAFF'S EDIT CREDIT?

A. Taking the recommended EDIT credit revenues for Year 1 as provided by Public Staff witness Boswell, I used the same approach as used by Company witness Pirro as shown in Pirro Exhibit 9. The recommended revenues and energy sales have been updated through January 31, 2020, and are consistent with the calculations of revenues and sales provided in the supplemental testimonies of Public Staff witnesses Boswell and Saillor, respectively.

Because Pirro Exhibit 9 assigns the Company's proposed EDIT credit to four broad customer classes, I was required to perform an additional step to assign the Public Staff's recommended EDIT credit to the five customer classes used in my revenue assignment analysis and the Company's cost-of-service studies.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ASSIGNMENT OF BASE REVENUES AND THE EDIT-2 CREDIT?

A. While my testimony provides an illustration of how base revenues and EDIT-2 credit should be assigned using the SCP and WCP cost-of-service methodologies, the Public Staff continues to believe that the SWPA cost-of-service methodology is the most appropriate methodology for this case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1187 In the Matter of Petition of Duke Energy Carolinas, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego DOCKET NO. E-7, SUB 1213 In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program DOCKET NO. E-7, SUB 1214 In the Matter of Application of Duke Energy Carolinas, LLC, for an Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)	CORRECTIONS TO THE FIRST SUPPLEMENTAL TESTIMONY OF JACK L. FLOYD PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

CORRECTIONS TO THE FIRST SUPPLEMENTAL TESTIMONY

OF JACK L. FLOYD

Mr. Floyd's first supplemental testimony should be corrected as follows:

1. The EDIT credit amount on Page 3, Line 2 should be $399,343,000.

2. On Page 3, Footnote 2 should read, "Sum of lines 51 through 54, Boswell Supplemental and Stipulation Exhibit 1, Schedule 1."

3. Corrected Floyd Supplemental Exhibits 1-4 are attached.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUBS 1187, 1213 AND 1214

SECOND SUPPLEMENTAL TESTIMONY OF JACK L. FLOYD
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 8, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jack L. Floyd. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an Engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. DID YOU PREVIOUSLY FILE DIRECT AND SUPPLEMENTAL TESTIMONIES IN THESE PROCEEDINGS?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SECOND SUPPLEMENTAL TESTIMONY?

A. The purpose of my second supplemental testimony is to present the Public Staff's recommended distribution of updated revenues through May 2020 based on the results of the summer coincident peak (SCP), winter coincident peak (WCP), and summer/winter coincident peak and average (SWPA) cost-of-service methodologies. My calculations are based on the request of Duke Energy Carolinas, LLC (DEC or the Company) for a base revenue increase and an Excess Deferred Income Tax (EDIT) rider, and the Public Staff's adjustments to that request. The adjustments reflect items agreed to in the First Agreement and Stipulation of Partial Settlement between DEC and the Public Staff (First Settlement Agreement) filed on March 25, 2020, and the Second Agreement and Stipulation of Partial Settlement between the Company and the Public Staff (Second Settlement Agreement) filed on July 31, 2020, as well as other adjustments recommended by the Public Staff on which the Public Staff and the Company have not reached agreement. The Public Staff's recommended base revenue increase of $290,049,000 and a Year 1 EDIT credit of $323,929,000 are provided in the second supplemental testimony and exhibits of Public Staff witness Boswell.[1] I have used this information to assign the revenues and credits to the customer classes.

My second supplemental testimony and exhibits also responds to the Second Settlement Testimony and Exhibits of Witness Michael J. Pirro filed on August 21, 2020, which reflect the First and Second Settlement Agreements as well as the Company's Agreement and Stipulation of Settlement with Carolina Industrial Group for Fair Utility Rates III (CIGFUR) filed on May 29, 2020, as amended on August 6, 2020 (CIGFUR Settlement). Additionally, I address terms of settlement related to rate

[1] Due to rounding Floyd Second Supplemental Exhibits, do not exactly reflect the "NC Retail" level base revenue increase and EDIT credit.

design included in separate settlement agreements filed between the Company and Harris Teeter, LLC (Harris Teeter Settlement) on May 28, 2020, and DEC and the Commercial Group (Commercial Group Settlement) on June 1, 2020.[2]

Q. DO YOU HAVE ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. My testimony includes four exhibits. Floyd Second Supplemental Exhibit 1 illustrates the rates of return (ROR) on rate base, the percentage change in base revenues, and the impact of the EDIT credit rider for each cost-of-service methodology. Floyd Second Supplemental Exhibits 2, 3, and 4 provide an illustration of the base revenue and EDIT credit assignments under an “equal rate of return” scenario and an “equal percentage increase” scenario for each cost-of-service methodology.

Q. HOW DID YOU ASSIGN THE PUBLIC STAFF’S RECOMMENDED REVENUE CHANGE AND EDIT CREDIT?

A. I assigned the Public Staff’s recommended revenue changes consistent with the revenue assignment principles discussed in both my direct and first supplemental testimonies. I also assigned the Public Staff’s recommended

[2] A settlement was filed on July 9, 2020, between Vote Solar and DEC, and a settlement was filed on July 23, 2020, between DEC and the North Carolina Sustainable Energy Association, the North Carolina Justice Center, the North Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy. My second supplemental testimony does not address these two settlements because they do not include any provisions affecting rate design.

EDIT credit consistent with the Second Settlement Agreement, which required that the EDIT credit rate use a levelized rider.

Q. WHY DOES YOUR ASSIGNMENT OF THE EDIT CREDIT DIFFER FROM THE METHOD USED BY COMPANY WITNESS PIRRO IN HIS SECOND SETTLEMENT EXHIBIT 9?

A. While the Company and the Public Staff agreed to use a levelized rider, i.e., a rider that would be at the same level each year, the Company agreed in the CIGFUR Settlement to return EDIT to customers on a uniform cents per kilowatt-hour (kWh) basis. This means each customer would receive the same credit amount per kWh, which would benefit industrial customers. I have used a fairer method to distribute the EDIT credit by returning the monies to customer classes based on amounts each class paid.

Q. DID MR. PIRRO'S SECOND SETTLEMENT EXHIBITS 4 OR 9 REFLECT THE HARRIS TEETER OR COMMERCIAL GROUP SETTLEMENTS?

A. No. The terms of those settlements would be reflected in the tariffs that would be filed should those settlements be approved.

Q. WHAT ARE THE TERMS OF THE HARRIS TEETER AND COMMERCIAL GROUP SETTLEMENTS THAT RELATE TO RATE DESIGN?

A. The Harris Teeter and Commercial Group Settlements include many of the same terms regarding rate design. Those terms require DEC to:

1. Recover any grid improvement expenses allocated to the OPT-V customer class through demand charges;
2. Set the off-peak energy rate in Schedule OPT-VSS at 3.022 cents/kWh;
3. Increase the on-peak energy rate by no more than half of the overall percentage increase assigned to Schedule OPT-VSS; and,
4. Adjust the demand charges in schedule OPT-VSS as necessary to achieve the final revenue target for OPT-VSS.

Q. BESIDES THE PROVISION REGARDING THE EDIT RIDER DISCUSSED ABOVE, WHAT ARE THE TERMS OF THE CIGFUR SETTLEMENT THAT RELATE TO RATE DESIGN?

A. The CIGFUR Settlement includes the following rate design terms:

1. Allocate grid improvement expenses consistent with the Company's allocation of distribution costs, including the use of the Minimum System Methodology;
2. Adjust the peak demands used in the cost of service to remove curtailable loads, whether activated or not;
3. For the next three rate cases, continue using the Minimum System Methodology for determining the customer- and demand-related distribution costs;

4. Give consideration for implementing a new high load rate schedule similar to Duke Energy Indiana's Schedule HLF[3];

5. Allow customers to enroll additional load into Schedule HP; and

6. Develop a new demand response rate schedule similar to Southern California Edison's Schedule TOU-BIP.[4]

Q. SPECIFICALLY RELATED TO YOUR OPPOSITION TO THE TERM OF THE CIGFUR SETTLEMENT THAT REQUIRES ADJUSTMENT OF PEAK DEMAND TO REMOVE INTERRUPTIBLE LOADS IN FUTURE COST OF SERVICE STUDIES, WHETHER ACTIVATED OR NOT, HAVEN'T YOU SUPPORTED THIS TYPE OF ADJUSTMENT IN A PREVIOUS RATE CASE?

A. In my testimony in Docket No. E-22, Sub 479 (Sub 479 Case), filed on September 24, 2012, in the application for a general rate increase of Dominion North Carolina Power (now Dominion Energy North Carolina, or DENC), I supported DENC's adjustment to impute the winter peak component had DENC activated all of its available demand-side management (DSM) programs at the time of the winter.[5]

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[3] See Duke Energy Indiana's Rate HLF at the following links: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-in/ratehlf.pdf?la=en and https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-in/optional-rate-hlf-rider-no-122.pdf?la=en

[4] See Southern California Edison's Schedule TOU-BIP and the following link: https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/general-service-&-industrial-rates/ELECTRIC_SCHEDULES_TOU-BIP.pdf

[5] Testimony of Jack L. Floyd, Docket No. E-22, Sub 479, filed September 24, 2012, at 6 – 8.

Q. ISN'T THERE AN INCONSISTENCY IN YOUR CRITICISM OF THIS TERM OF THE CIGFUR SETTLEMENT AND YOUR TESTIMONY IN THE SUB 479 CASE?

A. No, for several reasons. DENC supported a cost allocation methodology that equally weighted the summer and winter peaks. First, DENC had activated all of its DSM resources and interruptible loads at the time of its summer peak in the Sub 479 Case test year, but only activated a portion of those resources at the time of its winter peak. Thus, the relationship between the summer and winter peaks was distorted without the adjustment. For comparison, in this case, DEC has utilized the single summer peak for cost allocation. Second, DENC relied upon the Summer Winter Peak and Average (SWPA) cost of service methodology in the Sub 479 Case. Thus, even those customers who could contribute to reducing their peak loads could not avoid all production plant cost responsibility for the interruptible portion of their loads that was present in the other hours of the year, due to the average demand component of SWPA. Third, DEC did not activate any of its DSM or interruptible resources at the time of the summer peak. For DEC in this case, customers who had their interruptible load removed from cost of service, whether they actually were called upon to interrupt or not, would avoid paying any production plant related costs for that same load, even though the load was present for the remainder of the test year.

Q. DOES THE PUBLIC STAFF AGREE WITH ALL OF THESE TERMS REGARDING RATE DESIGN IN THE HARRIS TEETER, COMMERCIAL GROUP, AND CIGFUR SETTLEMENTS?

A. No, the Public Staff does not agree with all of the terms at this time. It is premature and counter-productive to begin redesigning rates and the terms of service under specific rate schedules, without having a full understanding of the rationale for the change and the impact on other rate schedules and revenues. The Company did not propose any significant changes in its rate schedules in this proceeding, nor has the Company conducted the necessary analysis to justify largescale changes to its rates at this time. Making discrete changes to individual rate schedules to satisfy individual customers or consumer groups simply constrains the ability to conduct a comprehensive study of rates and rate design in the future as I have proposed in my direct testimony. It would be shortsighted to implement specific changes now without having any understanding of the impact those changes on other customers. Given the “status-quo” nature of the Company’s current rate designs and schedules, any change that is made now simply as a matter of settlement hinders the ability to properly address rate of return issues in the next rate case proceeding.

The OPT-V structure and design was approved by the Commission September 19, 2014 (Docket No. E-7, Sub 1026) after a vigorous debate among the parties. I strongly caution the Commission against undertaking any rate changes or structural changes in the absence of any substantive analysis on the effects of such changes on other OPT-V customers and other customer classes. These unforeseen impacts would need to be addressed in a future rate case.

Limiting the off-peak energy charge to a specific amount as provided for in DEC's settlements with Harris Teeter and the Commercial Group is an example of a narrowly focused objective serving the interests of specific intervenors that forces the other rate elements in the OPT-VSS rate schedule, and possibly other OPT and non-OPT customers to assume the remaining burden of costs incurred to serve OPT-VSS customers. As I mentioned during my testimony in the consolidated phase of this hearing, such changes make a comprehensive rate study, "a little less comprehensive."

Q. CAN YOU EXPLAIN YOUR POSITION IN MORE DETAIL?

A. My direct testimony outlined six broad rate design principles that would be the basis for a comprehensive rate design study. Those broad principles require rates to:

1. Be forward-looking and reflect long-run marginal costs.
2. Be focused on the usage components of service that are the most cost- and price-sensitive.
3. Be simple and understandable.

4. Recover system costs in proportion to how much electricity consumers use, and when they use it.

5. Give consumers appropriate information and the opportunity to respond to that information by adjusting their usage.

6. Where possible, be dynamic.

The piecemeal approach incorporated in the CIGFUR, Harris Teeter, and Commercial Group Settlement Agreements runs counter to the comprehensive approach I advocate. These settlement agreements provide that specific rate elements and rate schedules will be constrained in specific ways, to the exclusion of all other rate design. The Public Staff believes that all of DEC's rate schedules need to be reviewed to determine if they remain germane to contemporary utility service, and in particular, to future service offerings. Given the myriad of changes taking place in electric utility service, the Public Staff believes that a comprehensive study is the only way to address these changes. DEC, the Public Staff, and interested stakeholders should have the opportunity to analyze and evaluate cost of service and rate design issues. Such a study will be undermined if DEC and specific customers are permitted to fix the prices for energy and demand rates for specific rate structures or mandate which rate elements will be designed to recover certain specific costs.

It is impossible to understand the impact these terms of settlement will have on future cost of service studies. By fixing certain rate elements now, the resulting revenue picture produced by the changes identified in the CIGFUR, Harris Teeter, and Commercial Group Settlement Agreements could result in a cost of service (as illustrated in returns on rate base) that indicates a certain rate schedule or rate class is under- or over-earning vis-à-vis assigned or allocated costs. This misrepresentation of the actual cost to serve certain customers and customer classes would require a shifting of revenue responsibility to other classes. The Public Staff is concerned that any rate exercise that does not comprehensively review and analyze all existing rate designs, and looks to develop new rate designs for the future, will simply be an exercise in creating new subsidies for certain customers.

Cost of service studies and rate design are inextricably linked; while rate design does not strictly follow cost of service studies in every instance, cost of service studies most definitely inform rate design. The Public Staff believes that a cost of service study aligned with the current rate design portfolio of electric tariffs should be the beginning of the comprehensive rate study. The Public Staff envisions a comprehensive rate study that follows the six broad principles outlined above, but more specifically, allows and encourages stakeholder input throughout the process.

A comprehensive study would take the existing portfolio of rate schedules, including all current principles and policies that inform the current components, and calculate rates as close to a purely cost-based approach as possible. The Public Staff envisions the following process:

1. Conduct a load study using Duke's new AMI (advanced metering infrastructure) network. Load shapes serve as the basis for developing rate designs. Load research studies can supplement AMI data as needed, but only as a secondary source when sufficient AMI data is not available.

2. Using the load shapes, Duke can begin to ascertain the distinguishing characteristics of customers and customer classes that would serve as the basis for a cost of service structure. Some of this work is already underway in the study ordered by the Commission in Docket No. E-100, Sub 101.

3. Begin building rate designs that allow customers some choice and flexibility in how they want to use energy and develop new rate designs using the costs to serve those customers.

After this exercise of determining a cost-based cost of service and rate design portfolio, the Commission could then apply any policy objectives it deems appropriate. This would provide a clear picture to the Commission about the costs, impacts, and any cross-subsidization that would accompany those policy decisions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY

A. Yes.

Summary of Testimony
(Direct, First Supplemental, and Second Supplemental)
Jack L. Floyd
Docket No. E-7, Subs 1213 & 1214

The purpose of my testimony today is to present the Public Staff's analysis and recommendations regarding rate design, rate schedules, and revenue assignment; the status of the deployment of advanced metering infrastructure; and the Prepaid Advantage Program.

With respect to rate designs, schedules, and revenues, I conclude that the Company's proposed modifications to its rate schedules are reasonable for purposes of this proceeding. I also discuss the Public Staff's revenue assignment principles that should be used to apportion any revenue increase approved in this proceeding. Those principles include maintaining the class rates of return on rate base within plus or minus 10% of the overall rate of return resulting from this case, moving all customer classes closer to the NC retail jurisdictional return, limiting any increase to a particular customer class to no more than two percentage points greater than the jurisdictional increase approved in this proceeding, and minimizing any subsidization amount the customer classes. However, in the event the Commission orders a decrease in the revenue requirement as recommended by the Public Staff, I believe it is more appropriate to focus on addressing disparities in the class rates of return. I also provides the Public Staff's assignment of the base revenue changes and the excess deferred income tax credits proposed by the Public Staff (Corrected First Supplemental testimony and Second Supplemental testimony and exhibits), which are consistent with these revenue assignment principles. It is important to understand that my recommendations on revenue apportionment are developed using the test-year cost of service study and rate schedule portfolio, updated as appropriate for both supplemental testimonies. These revenue principles should be incorporated in the comprehensive rate study I recommend in my testimony.

I also discuss the many changes occurring with electric utility service, and the need for the Company to undertake a comprehensive study of its rate designs to address these changes. I outline six broad principles for the study, as well as three other key objectives: to allow customers to connect to the grid for no more than the cost of the connection, to ensure that users of the system pay for service based on how they use the system, and to treat all users fairly and equitably. There should be no doubt that this formidable task will involve many stakeholders, and take time to develop and implement.

I also discuss several issues associated with the Company's AMI deployment. The Company has effectively completed its deployment of smart meters, which has allowed the Company to reduce its connection and reconnection charges. The AMI deployment also impacts the rates and costs associated with Rider MRM, which applies to customers who elect to opt-out of having a smart meter. However, very few customers have elected to opt-out of smart meters. While the Company did not propose changes to the charges in Rider MRM, I recommend that the Company maintain the current charges and that any additional costs associated with Rider MRM be socialized and recovered from all customers.

Last, I note that the AMI deployment should allow the Company to begin using the usage data available from these meters in its load research.

I also recommend that the Commission approve the Company's proposed Prepaid Advantage program. This program provides residential customers with a voluntary payment option that avoids the need for a deposit, reconnection fees, and late fees and is similar to a prepayment program offered in the Company's South Carolina territory. Rates for service would be the same as those under Schedule RS and would prorate any per account for flat charges applicable to Schedule RS. The Company has requested that certain Commission rules regarding meter readings and bills, requirement for deposits, and the process of discontinuing service be waived. I recommend that the Commission grant the waivers with certain conditions. I also recommend that the Commission require the Company to file quarterly reports on certain aspects of the Program.

Based on my investigation and from testimony at the public hearings, it appears that having the option to prepay for electric service would benefit a number of customers, especially those who desire greater ability to manage their energy consumption and control over how they pay for electric service, including avoidance of the administrative fees that accompany post-paid service. In addition to avoiding fees such as those associated with late fees and deposits, Prepaid Advantage transaction fees will be treated the same as post-pay transactions, and recovered from all customers.

This concludes my summary.

MS. EDMONDSON: And the panel is available for cross examination.

CHAIR MITCHELL: All right. We will begin with the commercial group, Mr. Jenkins.

MR. JENKINS: Thank you, Madam Chair.

CROSS EXAMINATION BY MR. JENKINS:

Q. Gentlemen, it's a privilege to cross examine such an illustrious group.

Mr. McLawhorn, let's begin with you, if I may. I direct you to page 33 of your direct testimony. Are you there, sir? Mr. McLawhorn, can you hear me?

A. (James S. McLawhorn) I can hear you, Mr. Jenkins.

Q. Okay. At page 33 of your direct testimony, you provide there and in your exhibits the results of three class cost of service studies; is that right?

A. That's correct.

Q. Why did you do that?

A. Well, several reasons. One, one of the cost of service studies, the summer/winter peak and average, is at the time of the filing of my direct testimony as the Public Staff's preferred cost of service methodology, the summer CP or SCP is the one that Duke filed and they preferred with their prefiled -- their application in this proceeding. And then the winter coincident peak was one that Duke had also included in their application. So I provided analysis and comments on those three methodologies.

In addition, the Commission had expressed some interest in an order they issued in January. I believe it was January 20th or thereabouts. I'd have to check that date. In that they wanted the Public Staff to comment on an analysis of various cost of service methodologies.

Q. And so do you believe that providing various class cost of service study method results might give the Commission a better view concerning those results?

A. Well, it certainly allows them to look at these three, in particular, and see what type of results were produced in -- during the test year of 2018.

Q. Okay. And one of the methods is the winter coincident peak that you mentioned that uses DEC's current yearly peak; is that correct?

A. It used the peak for 2018, yes.

Q. Under the -- that WC method that you also show in your Exhibit 2, doesn't the OPT class currently provide revenues that greatly exceed DEC's cost to serve that class?

A. (Witness peruses document.)

Under that methodology, it did provide a rate of return that was in excess of the retail rate of return for that given year, yes. Although --

Q. And if you were -- sorry.

A. May I finish my answer? Although I would note that, in the other two methodologies that were presented, the SCP which Duke has advocated in this case, and the SWPA, the OPT rates of return were substantially below the retail rate of return for 2018.

Q. And if you were to blend the results from these three class cost of service methodologies, wouldn't the blended results show that the OPTG class should receive a rate increase that is below the system average?

A. I have not done that analysis to determine what the rate increase would be. If you averaged the rates of return together, you would certainly get a number that is above the rate of return for SCP and SWPA, although I'm not a fan of averaging averages, because you're not always comparing apples to apples in that case. You would be comparing rates of return that were based on different levels of rate base since the different methodologies arrive at different NC retail rate base amounts.

Also, I think what it would be showing you is that the WCP methodology results in a substantially different result than the other two methodologies. So it's -- you know, for lack of a better term, if you're comparing the three, it would appear to be somewhat of an outlier. And we could talk about the reasons why if you want to, but I'll leave that up to you.

Q. Okay.

MR. JENKINS: Thank you, Madam Chair, that's all I have for Mr. McLawhorn. I do have other questions for Mr. Floyd, but this might be a good time to break.

CHAIR MITCHELL: All right, Mr. Jenkins, let's do go ahead and take our lunch break. We will go off the record now, and we will go back on at 1:30. Thank you very much.

MR. JENKINS: Thank you.

(The hearing was adjourned at 12:30 p.m. and set to reconvene at 1:30 p.m. on Thursday, September 10, 2020.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appear in the foregoing hearing were duly affirmed; that the testimony of said witnesses were taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 12th day of September, 2020.

JOANN BUNZE, RPR
Notary Public #200707300112