REDACTED

PLACE: Held Via Videoconference

DATE: Wednesday, September 9, 2020

TIME: 9:00 A.M. - 12:47 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 Daniel G. Clodfelter

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-7, SUB 1214

In the Matter of

Application by Duke Energy Carolinas, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

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 1187

In the Matter of

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 16

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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

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 Cont'd.

E X H I B I T S

E X H I B I T S Cont'd.

P R O C E E D I N G S

CHAIR MITCHELL: All right. Good morning, everyone. It's 9:00. Let's go on the record, please. We will resume with questions on Commission's questions for the Speros/McManeus Panel. Any Intervenors have questions on Commission's questions, beginning with the Public Staff?

MS. HOLT: No questions.

CHAIR MITCHELL: Attorney General's Office?

MS. FORCE: No questions.

CHAIR MITCHELL: Any additional Intervenors have questions on Commission's questions?

(No response.)

CHAIR MITCHELL: Questions from Duke?

MS. JAGANNATHAN: No questions, Chair Mitchell. I would just note that we're working on a more detailed accounting of DEC's cost of removal reserve, as requested by Commissioner Clodfelter during Commission questions, and we'll plan to file that as a late-filed exhibit.

CHAIR MITCHELL: Okay. Thank you, Ms. Jagannathan. All right. At this time do I need to entertain any motions?

(No response.)

CHAIR MITCHELL: All right. Well, with that --

MS. JAGANNATHAN: Oh, excuse me.

CHAIR MITCHELL: Ms. Jagannathan, go ahead.

MS. JAGANNATHAN: With respect to this Panel, I would just -- Chair Mitchell, if now is the right time, I would like to move Mr. Speros' prefiled exhibits into evidence as premarked and also move to excuse witness Spero.

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

(Whereupon, Speros Exhibits 1-3, Revised Speros Exhibit 4, Speros Supplemental Exhibits 2-3, and Speros Rebuttal Exhibit 1 were admitted into evidence.)

CHAIR MITCHELL: The witnesses may step down, and Mr. Speros may be excused.

MS. JAGANNATHAN: Thank you.

MS. FORCE: Chair Mitchell, this is Margaret Force.

CHAIR MITCHELL: Yes, Ms. Force.

MS. FORCE: Excuse me. I'd like to move the cross examination exhibits marked as AGO McManeus/Speros Cross Exhibits 1 through 5, please.

CHAIR MITCHELL: All right, Ms. Force. Hearing no objection, your motion is allowed.

MS. FORCE: Thank you.

(Whereupon, AGO McManeus/Speros Cross Examination Exhibits 1-5 were admitted into evidence.)

CHAIR MITCHELL: All right. Ms. Force and Ms. Townsend, we are now with the Attorney General's office. You may call your witness.

MS. CRESS: Chair Mitchell, I apologize for the interruption. This is Christina Cress with CIGFUR. Now that Duke has finished its direct case and we are moving into the Intervenors' portion of this proceeding, I would like to make a motion at the outset, if the Chair is so willing to hear it.

CHAIR MITCHELL: All right. You may proceed, Ms. Cress.

MS. CRESS: Thank you, Chair Mitchell. At this time CIGFUR makes a Motion to Strike the Public Staff witness Floyd's second supplemental testimony filed yesterday afternoon, as it pertains to any testimony related to CIGFUR's settlement with the Company. In support of this motion, which by the way I understand is supported by the Company -- in support of this motion, I would like to draw the Commission's attention to the fact that CIGFUR's settlement with Duke was filed in this docket on May 29th. That was more than three months ago.

The Public Staff has had ample opportunity since that time to either formally or informally object or protest to any of the provisions contained within that Settlement Agreement and has not done so. For the very first time in this proceeding, the Public Staff's witness Floyd, during the consolidated portion of the rate case, provided some live testimony, and that was CIGFUR's very first notice that the Public Staff was going to be objecting to anything contained in CIGFUR's Settlement Agreement.

The Public Staff, on July 7th, filed a response to the Company's second supplemental testimony. They could have included an objection at that time. They did not.

On July 31st the Public Staff filed testimony in support of its Second Partial Stipulation and Settlement with the Company. That also would have been an appropriate time for the Public Staff to have noted its objection to CIGFUR's settlement. Again, they failed to do so.

The Public Staff never so much as provided CIGFUR the professional courtesy of informally notifying us that it was going to be protesting CIGFUR's settlement or any of the terms contained therein and, in fact, CIGFUR would contend that all signals received prior to the live testimony of Mr. Floyd in the consolidated portion of this hearing actually indicated to the contrary. For example, on Friday, July 17th, the Public Staff, via email from Beth Culpepper, affirmatively consented to CIGFUR's then forthcoming motion to excuse witness Phillips from testifying in this proceeding. The Public Staff at that time, of course, had already indicated that it had no cross examination for witness Phillips, and it did affirmatively consent to CIGFUR's motion.

But perhaps most concerning of all is the fact that the Public Staff's Motion for Leave to file the second supplemental testimony of Witness Floyd, which was filed yesterday afternoon, specifically limited the purported scope of what that second supplemental testimony was supposed to address. Relying on the veracity of representations made by the Public Staff to CIGFUR, CIGFUR did not object to Public Staff's Motion for Leave to file this testimony, but unfortunately, after having had the opportunity to review witness Floyd's testimony yesterday afternoon, I'm left to form no other conclusion other than to conclude that the representations made by the Public Staff in support of its Motion for Leave to file this testimony were either incomplete, at best, or deliberately misleading, at worst.

To be clear, CIGFUR moves to strike the relevant portions of witness Floyd's second supplemental testimony on the grounds that they are -- that it's wholly beyond the scope of the testimony for which the Public Staff moved for and the Commission granted leave. And that motion was filed in this docket on August 31st. It was previously circulated with the parties, and that is why CIGFUR did not object after it had a chance to review that motion because the motion did not, in any way, shape, or form, provide notice that this was going to be part of witness Floyd's second supplemental testimony. The Public Staff has had ample opportunity to address CIGFUR's settlement in another way, and to file late testimony at the eleventh hour, once we're already in the middle of this proceeding and after CIGFUR has already prepped its witness to testify, given that at the time of this testimony being filed in the docket we were likely within 24 hours of CIGFUR's witness taking the stand, that all of this, in totality, constitutes a completely unfair surprise, and depending on how the Commission rules on its Motion to Strike, CIGFUR may have additional motions or requests for the Commission. Thank you.

CHAIR MITCHELL: All right. I'd like to hear from Public Staff.

MS. EDMONDSON: This is Lucy Edmondson with the Public Staff.

CHAIR MITCHELL: All right. Please proceed, Ms. Edmondson.

MS. EDMONDSON: And I have not been involved with the communications between CIGFUR or with Duke, however, it is my understanding that we have communicated -- I believe Mr. Somers has had some communications with Ms. Downey, is aware that we were planning to -- we were not -- we had some concerns about the settlement and were intending to address them. Mr. Floyd's testimony, one of the biggest issues is how the EDIT is distributed, does rate design differently than the CIGFUR agreement, and he explains why he does that. Mr. Pirro's second settlement testimony indicates that he distributes it pursuant to the CIGFUR agreement, so it's only appropriate that Mr. Floyd's testimony explains why he does it differently. The motion to file the testimony indicated that we were going to address the second settlement testimony, which we did appropriately. The Commission's Order allows the parties to file rebuttal testimony, and we have no problem with that. And we -- we said we were going to do rate design and, indeed, that's what Mr. Floyd has done.

The Commercial Group and Harris Teeter settlements were not directly addressed in Mr. Pirro's testimony. I do agree with that. And -- however, those -- those settlements will be used in the ultimate rate design, and Mr. Floyd is our rate design witness. To the extent that -- to the extent that the Commission would strike that testimony, the Public Staff believes we should be able to address those at least in live testimony. I don't believe the Public Staff has to file an objection to any settlement. That's not something that is procedurally correct. There is no requirement that we do that. And I believe -- I don't know if Mr. Somers communicated that to the other parties, that we had some concerns with the settlement, but I do believe he was aware of that.

And finally, as I said, we have no objection to any party filing rebuttal. If there is more time needed, we don't have any problem with that. And so -- and I don't believe we had any intent to deceive any parties.

We've not hidden the ball in any way.

MS. CRESS: Chair Mitchell, if I may be heard briefly.

CHAIR MITCHELL: You may.

MS. CRESS: Chair Mitchell, I did not say that the Public Staff had to file an objection. I merely stated that there were plenty of opportunities between May 29th and yesterday that would have been a much more appropriate time and opportunity for the Public Staff to have noted through its first testimony related to the Second Settlement and Stipulation with the Company. For example, there's absolutely no reason why the CIGFUR settlement was not addressed until the Public Staff's second supplemental testimony, filed yesterday. That should have been something that was included in the first supplemental testimony following the Public Staff's Second Stipulation and Settlement with the Company. It was not, and this does not constitute a change in circumstances or new information that was not already known by the parties. This was something, again, that's been in the docket, that's been in the record for three months -- more than three months.

So, again, for these reasons we would move to strike. And to the extent that the Public Staff intends for this to come in in live testimony, CIGFUR would also make a Motion in Limine that the Public Staff has, at this point, waived its opportunity to object to the provisions contained within CIGFUR's Settlement Agreement.

MR. JENKINS: Madam Chair, if I may? This is Alan Jenkins. The Commercial Group --

CHAIR MICHELL: Mr. Jenkins, one moment, please. I'll just remind the parties, I'm looking at a screen right now that has approximately 30 people on it, so it would be -- it would be most appreciated and helpful to me if prior to beginning to speak, announce your -- announce who you are so that I can identify you and look for you on my screen. So, Mr. Jenkins, you may -- you may proceed.

MR. JENKINS: Thank you. Commercial Group also moves to strike portions of the Floyd testimony addressing the Commercial settlement, namely, the Harris Teeter and the Commercial Group settlements, for all the same reasons as was already mentioned. And I'd also add that on July 2nd, Duke filed the testimony of witnesses McManeus and Pirro which addressed the Commercial settlements and the financial impact of those settlements. A month later, Staff filed its settlement testimony and did not say anything about the Commercial settlements. And it is now the day before the hearing on Staff and Intervenor testimony, Staff files this testimony.

And I note an additional point, that Mr. Floyd admits at page 5, lines 13 to 16, that Mr. Pirro's second settlement testimony, to which he's supposed to be responding, does not address the Commercial settlements, and -- and the rest of his testimony also notes that he only addressed the two settlements Staff has with Duke and, to some extent, CIGFUR settlement. So there's no mention in the Pirro testimony of the Commercial settlements, and so there's -- it's way out of time to have to be raising new testimony at this point. In fact, its testimony date was February -- in February, way before COVID, but it would be patently unfair now for Staff to introduce testimony at this point.

And I -- and I note that five out of the 13 pages of Mr. Floyd's testimony addresses the Commercial settlements, again, something that was not even in Mr. Pirro's testimony. And, specifically, we would move to strike beginning at page 3 from the word "Additionally," line 20, through page 4, line 4; next page 5, line 17, through page 6, line 9; and finally, pages 9, 10, 11, 12, in their entirety, through page 13, line 18. Thank you.

CHAIR MITCHELL: All right. Ms. Cress, would you please indicate which portions of Mr. Floyd's testimony that you seek to strike?

MS. CRESS: All mentions of CIGFUR. I -- I can provide not right this second, but if the Commission so would like, I can provide specific lines. But essentially, we would move to strike all portions of the testimony that directly or indirectly reference CIGFUR's settlement with Duke.

CHAIR MITCHELL: All right. Thank you, Ms. Cress. Mr. Somers, do you wish to be heard?

MR. SOMERS: Yes. Good morning, Chair Mitchell. This is Bo Somers. I'd just like to briefly comment on the motions that have been made today by the Commercial Group and CIGFUR. In the Company's settlement with the Public Staff, the Public Staff reserved their right to cross examine witnesses regarding other settlements reached, and the Companies do not take any issue with the Public Staff's right to oppose any settlement that they wanted to. However, our concern is that the purpose of the second supplemental testimony filed yesterday by Mr. Floyd was to address the audit of the May updates. That was the specific purpose of that testimony. And by getting into the settlements here, it's the Company's position that that is outside the scope of what they were asking to do and what they're allowed to do here. Again, the Companies have no objection if Public Staff wants to cross examine witnesses about the settlements, but we believe, likewise, that the testimony is inappropriate, and for that reason should not be made part of the record. Thank you.

MR. BOEHM: Madam Chair, Kurt Boehm with Harris Teeter.

CHAIR MITCHELL: All right, Mr. Boehm. You may proceed.

MR. BOEHM: I would just like to join the Motion to Strike and note that the Harris Teeter settlement was filed on May 28, 2020, and as the counsel for CIGFUR and the Commercial Group have indicated, we've also not had any indication from Staff that they opposed the settlements until -- until yesterday. So for all the reasons the -- that the other attorneys have articulated, we join the motions.

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

CHAIR MITCHELL: Mr. Neal, one moment, please. Mr. Boehm, you trailed off at the end. I just want to make sure that we've captured the full extent of your motion. Can you please just restate the last sentence so that we make sure that we -- we've captured it?

MR. BOEHM: Thank you, Madam Chair. I believe I said that we join the motions of CIGFUR and the Commercial Group.

CHAIR MITCHELL: All right. So just for purposes of our court reporter, I believe Mr. Boehm said that his client joins the motion of CIGFUR and the Commercial Group. All right. Mr. Neal, you may proceed.

MR. NEAL: Chair Mitchell, thank you. David Neal on behalf of Justice Center, et al. I just wanted to make sure that the Commission and ruling on this motion did not make any general--- generalizable rulings about waiver to oppose settlements as a legal matter because as I understand the procedural schedule laid out, Intervenors generally would not have had an opportunity to provide additional testimony in opposition to settlements, but may reserve the right to be against individual components of settlements in post-hearing briefs or other pleadings following the hearing. And so I just wanted to point out that to the extent that the argument about waiver is an element in this motion, that it doesn't get extended so far as to prohibit Intervenors from weighing in at the appropriate time.

CHAIR MITCHELL: All right. Any other party wish to be heard?

MS. FORCE: Madam Chair, Margaret Force with the Attorney General's Office. I join Mr. Neal's comments on this. We have not reviewed the motion. I guess this is just -- just came up this morning, and we -- I'd ask that the Chair take this under advisement and give an opportunity for parties to take a look at this more carefully before the ruling is made, but also joining settlements are a piece of evidence that's considered by the Commission, along with all the other evidence in the case.

CHAIR MITCHELL: All right. Thank you, Ms. Force. Anyone -- any other party wish to be heard?

MS. EDMONDSON: If I could be heard a little further. I would just -- there seems to be the implication that since the Public Staff did not file testimony opposing these settlements, that we are somehow estopped from opposing them, and that is simply wrong. Mr. Floyd's testimony explains why his rate design did not adopt the CIGFUR settlement. We raised these issues with Duke early on and during settlement discussions. We told the Commission that we were going to do rate designs, and we couldn't do them till we had the final numbers from our audit. And I just believe Mr. Floyd's testimony, especially about the CIGFUR Settlement, is -- is proper. It explains why his numbers and his rate design is different. And if anything, we should be able to explain in live testimony why we oppose these settlements. Thank you.

CHAIR MITCHELL: All right. I'm going to take the matter under advisement. I will issue a ruling at a later point in time. All right.

MS. CRESS: Chair Mitchell, I apologize, this is Christina Cress with CIGFUR. Again, in light of the Commission's taking this under advisement and not providing a ruling at this time, I would just like to request permission to have CIGFUR witness Phillips provide testimony out of order. Given that we were given less than 24 hours notice through witness Floyd's testimony, and CIGFUR's witness had already been prepped to testify before we received this late, eleventh hour testimony yesterday afternoon, CIGFUR needs more time to re-prepare its witness in light of the contentions made by Mr. Floyd and is not going to be prepared to take the stand today. And, in fact, we would request permission that we be allowed to take the stand either after Mr.

Floyd takes the stand or at a later time, and also have the opportunity to provide rebuttal testimony. I guess that would be a Motion for Leave. Thank you.

CHAIR MITCHELL: All right, Ms. Cress. This is what I'm going to ask of the parties, when we go on our first morning break, for the court reporter I want the parties to work together to figure out order of witnesses in light of this morning's events and motions made, and the fact that I've decided to take the motions under advisement. So when you all determine the appropriate order of witnesses for the intervening parties, I would ask that when we go back on the record after our morning break, you so inform us so that we will -- can proceed accordingly.

All right. With that, Attorney General's Office, please call your witness.

MR. QUINN: Madam Chair, this is -- I apologize for the interruption. This is Matthew Quinn with NC WARN, and I have one procedural matter to address, and it's not nearly so exciting as what we just witnessed, but if this is an appropriate time to move in -- now that we've begun Intervenor testimony, is this an appropriate time to move into the record prefiled direct testimony for witnesses who have been excused from attending the hearing in person?

CHAIR MITCHELL: You may do so, Mr. Quinn.

MR. QUINN: All right. Thank you. NC WARN sponsored witness William E. Powers in this docket. His prefiled direct testimony, consisting of 25 pages and no exhibits, was filed in this docket on April 13th (sic) of 2020. Mr. Powers' presence was excused for this hearing by the Commission on July 16th, 2020, and we would ask that that prefiled direct testimony be admitted into the record as if read from the stand.

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

MR. QUINN: Thank you.

(Whereupon, the prefiled direct testimony of William E. Powers was copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1214

In the Matter of: Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Services in North Carolina.	)))))	DIRECT TESTIMONY OF WILLIAM E. POWERS ON BEHALF OF NC WARN

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William E. Powers, P.E. My business address is Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, CA 92116.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. My employer is Powers Engineering. I am the founder and principal of the company.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am a consulting and environmental engineer with over 35 years of experience in the fields of power plant operations and environmental engineering. I have worked on the permitting of numerous combined cycle, peaking gas turbine, micro-turbine, and engine cogeneration plants, and am involved in siting of distributed solar photovoltaic (PV) and battery storage projects. I have been an expert witness is high voltage transmission application proceedings in California, Missouri, and Wisconsin, and have evaluated the impact of rooftop solar and battery storage on electric distribution systems for multiple clients. I began my career converting Navy and Marine Corps shore installation projects from oil firing to domestic waste, including wood waste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo in the 1970's.

I authored "San Diego Smart Energy 2020" (2007) and "(San Francisco) Bay Area Smart Energy 2020" (2012), and have written articles on the strategic cost and reliability advantages of local solar over large-scale, remote, transmission-dependent renewable resources. I have a B.S. in mechanical engineering from Duke University, an M.P.H. in environmental sciences from UNC – Chapel Hill, and am a registered professional engineer in California and Missouri.

Q. HAVE YOU EVER TESTIFIED BEFORE THE N.C. UTILITIES COMMISSION (THE "COMMISSION") OR ANY OTHER REGULATORY BODIES IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified on behalf of NC WARN in Docket No. EMP-92, SUB 0, Application of NTE Carolinas II, LLC for a Certificate of Public Convenience and Necessity to Construct a Natural Gas-Fueled Electric Generation Facility in Rockingham County, North Carolina. I have also offered affidavit testimony and reports to this Commission in prior dockets, such as Docket No. E-2, Sub 1089. Further, I have offered testimony before other utilities commissions across the country, such as the commissions in California, Missouri, and Wisconsin.

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

A. The purpose of my testimony is: 1) to address the need for the Commission to reject the Grid Improvement Plan ("GIP") capital investment program as unreasonable, and 2) to contest cost recovery by DEC for the natural gas conversion projects at the Belews Creek and Cliffside coal-fired power plants.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony consists of two parts. Part I will address the reasons why the Commission should reject the GIP as unreasonable. Part II will discuss the reasons why the Commission should reject cost recovery for the natural gas conversion projects at Belews Creek and Cliffside.

I. THE GIP SHOULD BE REJECTED

Q. WHY ARE YOU ADVOCATING THE COMMISSION REJECT COST RECOVERY OF THE GIP?

A. Duke Energy Carolinas LLC ("DEC" or "Duke Energy") has proposed to spend over $2.3 billion over three years on its GIP capital projects – many of which Duke Energy and the Commission have identified as indistinguishable from traditional spend transmission and distribution (T&D) projects[1] – with no formal application(s) or associated evidentiary processes to evaluate the reasonableness of the proposed expenditures or potential alternatives that negate the need for these proposed expenditures.

[1] DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, pp. 127-150.

Q. WHAT IS THE SCOPE OF THE GIP?

A. Duke Energy lists eighteen separate elements to the GIP, as shown in Table 1, totaling $2,319.2 million. The most costly single cost element is "Self-Optimizing Grid," with a capital expenditure of $722.5 million shared between DEC and Duke Energy Progress LLC ("DEP"). Ten of these eighteen GIP elements have capital budgets in excess of $100 million.

Table 1. Elements and Budgets for 2020-2022 GIP Programs[2]

GIP Program	DEC Budget, $ millions	DEP Budget, $ millions	Total Expenditure, $ millions
Physical & Cyber Security	65.1	68.7	133.8
Self-Optimizing Grid	420.1	302.4	722.5
Integrated Volt/VAR Control	206.7	10.0	216.7
Hardening & Resiliency	102.5	31.3	133.8
Targeted Undergrounding	59.8	54.7	114.5
Energy Storage (*)	*56.5*	*72.5*	*129.0*
Transformer Retrofit	8.3	109.7	118.0
Long Duration Interruptions	11.3	15.8	27.1
Transformer Bank Replacement	33.7	82.7	116.4
Oil Breaker Replacement	115.6	84.7	200.3
Enterprise Communications	103.7	108.1	211.8
Distribution Automation	115.4	78.9	194.3
System Intelligence	62.7	23.7	86.4
Enterprise Applications	17.0	10.8	27.8
ISOP	4.1	2.5	6.6
DER Dispatch	4.5	2.9	7.4
Electric Transportation (*)	*38.2*	*25.3*	*63.5*
Power Electronics	0.7	1.1	1.8
Total			2,319.2

(*): Duke Energy excludes Energy Storage and Electric Transportation projects from the GIP total.

Q. OTHER THAN DUKE ENERGY'S OWN INTERNAL ANALYSIS AND STAKEHOLDER WORKSHOPS, HAS MORE FORMAL VETTING OF THE GIP OCCURRED?

[2] DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC, Jay Oliver Direct Testimony, September 30, 2019, Exhibit 10, pdf p. 158.

A. No. Duke Energy witness Oliver stated "DE Carolinas' Grid Improvement Plan was developed through a comprehensive analysis of the trends affecting our business in the state and the tools to best address those trends in a cost-effective and timely manner." The stakeholder workshops are essentially sales presentations by Duke Energy to stakeholders, many of whom have no technical background in the provision of electric power, on the benefits of the GIP. There has been no formal Commission process to probe whether the alleged benefits are real, whether the benefits justify the costs, and whether alternatives could achieve the same objectives at less cost.

Q. IS IT YOUR POSITION THAT THE STAKEHOLDER WORKSHOPS SPONSORED BY DUKE ENERGY AT THE DIRECTION OF THE COMMISSION ARE INSUFFICIENT REVIEW OF THE SCOPE AND COST OF THE GIP?

A. Yes. The high cost of the GIP alone, about $2.3 billion in capital expenditures over three years between DEC and DEP,[3] is sufficient by itself to mandate an additional rigorous review to protect ratepayers. The GIP as proposed also presumes that there is only one pathway to grid modernization and grid hardening, with no assessment of alternatives that may be much less costly and achieve the stated goals more effectively.

Q. DOES DUKE ENERGY INDICATE ITS TRANSMISSION AND DISTRIBUTION GRID IN NORTH CAROLINA IS SAFE AND RELIABLE WITHOUT GIP EXPENDITURES?

[3] Ibid.

A. Yes. Duke Energy Witness Oliver states that "Our (transmission and distribution) system has performed well, and we have continued to provide safe, reliable, and affordable electric service to our customers."[4] In its 2018 general rate case, Duke Energy Witness Simpson "acknowledged that the grid has evolved over decades, and is more hardened today in terms of quality of design than it used to be."[5] Witness Simpson also testified that the company's reliability metrics typically vary from year to year, and conceded that DEC actually saw an improving trend from 2003 to 2012 without the implementation of a Power Forward-type program or a rider.[6] This Duke Energy testimony makes clear that the company's traditional expenditure levels on transmission and distribution, without GIP, are adequate to provide safe and reliable transmission and distribution service.

Q. CAN YOU GIVE AN EXAMPLE OF WHERE DUKE ENERGY PRESUMES WITHOUT ANALYSIS THAT THERE IS ONLY ONE APPROACH AVAILABLE TO THE IDENTIFIED DEFICIENCY THAT GIP IS INTENDED TO RESOLVE?

A. Yes. An example is the presumption by Duke Energy that targeted undergrounding is the only solution to further reduce outages caused by conductor contact with vegetation. Duke Energy identifies the benefits of targeted undergrounding as: significantly reduce outages, minimize momentary

[4] DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC, Jay Oliver Direct Testimony, September 30, 2019, p. 20.
[5] DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, p. 130.
[6] Ibid, p. 132.

interruptions, restore power faster, eliminate tree trimming in hard-to-access areas.[7]

Duke Energy acknowledges that vegetation contact is responsible for 20 to 30 percent of outages.[8] However, the company implies that its vegetation management program is as good as it can be, and therefore presumptively no further vegetation management improvement is possible: "For the outages that occur because of trees inside the right-of-way, even a perfectly executed integrated vegetation management plan will not bring this number down to zero but instead will only help minimize vegetation outages."[9] Duke Energy also asserts that 50 percent of the vegetation outages are caused by trees located on private property outside its right-of-way and that it does not have the ability to address these trees.[10] Based on this information, Duke Energy makes the conclusory statement that "Drastic clear cutting and going onto customer property and cutting down live trees via condemnation or negotiating with customers for rights on their property is also impractical and not cost effective."[11] This assertion then introduces the alleged benefits of targeted undergrounding with the statement that "programs such as Targeted Undergrounding . . . can be effectively used to

[7] DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC Jay Oliver Direct Testimony, September 30, 2019, pdf p. 566.
[8] Ibid, p. 7. "This work seeks to improve overall reliability, harden the grid against severe weather, and reduce the impact of vegetation which currently accounts for 20 to 30 percent of outages across the system."
[9] Ibid, p. 27.
[10] Ibid, p. 27.
[11] Ibid, pp. 27-28.

address vegetation outages caused by trees outside of the right-of-way."[12] Duke Energy proposes to spend $114.5 million on targeted undergrounding projects.[13]

Q. IS DUKE ENERGY'S CONCLUSORY STATEMENT ABOUT THE IMPRACTICALITY OF MORE EFFECTIVE VEGETATION MANAGEMENT A SUFFICIENT BASIS TO JUSTIFY A $114.5 MILLION TARGETED UNDERGROUNDING CAPITAL EXPENDITURE?

A. No. Duke Energy has made clear that a primary objective of the GIP is to increase shareholder value by accelerating the tempo of capital projects.[14] In this context, the company proposes $114.5 million in capital expenditure on targeting undergrounding. The estimated cost of a distribution line overhead-to-underground conversion is more than $2 million per mile in urban and suburban areas.[15] Based on this undergrounding cost-per-mile, Duke Energy will underground about 60 miles of distribution line in this GRC cycle.

Vegetation management is also a tool used by Duke Energy to minimize outages on overhead lines. As noted by Witness Oliver, the company has established the 5/7/9 Plan vegetation management program in 2013.[16] An

[12] Ibid. p. 28.
[13] See, *supra*, Table 1.
[14] DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, p. 129. Duke Energy Witness Fountain also admitted that Power Forward is part of Duke Energy's corporate policy intended, as quoted in a Duke investor earnings call, "to drive 4 to 6 percent earnings growth."
[15] Pacific Northwest National Laboratory, *Electricity Distribution System Baseline Report*, July 2016, p. 40. See: https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20Distribution%20System%20Baseline%20Report.pdf.
[16] DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC, Jay Oliver Direct Testimony, September 30, 2019, p. 24. "Duke Energy's . . . tree-trimming cycle with targeted trim dates by classification include(es) old-urban 5-year cycle, mountain 7-year cycle, and other 9-year cycle, otherwise referred to by the Company as the 5/7/9 Plan."

improved vegetation management program, more frequent than the old-urban 5-year cycle, on the estimated 60 miles of overhead distribution lines that would otherwise be undergrounded by Duke Energy may be able to achieve the same level of outage reduction projected for undergrounding at a fraction of the cost. An improved vegetation management program option should have been considered to assure that any expenditures on targeted undergrounding are just and reasonable for ratepayers.

Q. ARE THERE REASONABLE AND PRACTICAL ALTERNATIVES TO DEC'S UNDERGROUNDING PLAN?

A. Yes. It would be practical and less costly to put battery storage in every home along a proposed distribution line undergrounding route. Green Mountain Power ("GMP"), a Vermont investor-owned utility, implemented a virtual power plant ("VPP") in 2017, approved by the Vermont Public Utility Commission, consisting of aggregating and dispatching up to 2,000 residential Tesla Powerwall™ battery storage units.[17,18] GMP customers participating in this program have the option to purchase the Powerwall™ for a one-time cost of $1,500 or $15 per month over ten years.[19] The first phase of this project, consisting of 500 Powerwall™ units, saved GMP more than $500,000 over several days during a 2018 summer heat

[17] The Tesla Powerwall™ has a discharge capacity of 5 kilowatts (kW) continuous and a storage capacity of 13.5 kW-hours. See: https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf.

[18] Green Mountain Power, *Notification - Tesla Powerwall Grid Transformation Innovative Pilot*, submitted to Vermont Public Utility Commission, July 31, 2017. See: http://apps.psc.wi.gov/pages/viewdoc.htm?docid=364977.

[19] Ibid, p. 2.

wave.[20] Assuming the presence of a comparable program in Duke Energy North Carolina territory, it would cost about $300,000 per mile to equip every home in a North Carolina neighborhood with a Tesla Powerwall™.[21] $300,000 per mile to assure reliability during outages in every home along a distribution line pathway is a small fraction of the more than $2 million per mile for an overhead-to-underground distribution line conversion along the same route. The home battery storage option is an example of alternatives to the undergrounding capital budget that have not been examined or deployed by Duke Energy.

Q. DUKE ENERGY PROPOSES CAPITAL EXPENDITURES OF $133.8 MILLION FOR "HARDENING AND RESILIENCY." WHAT IS HARDENING AND RESILIENCY?

A. The company defines hardening and resiliency capital projects as "retrofitting transformers to eliminate common outage causes, replacing aged or deteriorating cable and conductors, and providing back feed capability to vulnerable communities."[22] However, Duke Energy also acknowledges that ". . . energy storage solutions may offer more cost-effective solution(s) for improving reliability and managing costs."[23] Witness Oliver includes a description of the Hot

[20] Utility Dive, *Tesla batteries save $500K for Green Mountain Power through hot-weather peak shaving*, July 23, 2018. See: https://www.utilitydive.com/news/tesla-batteries-save-500k-for-green-mountain-power-through-hot-weather-pea/528419/.

[21] Assume each home has a street-front property length of 50 feet. Therefore, there are about 100 homes per mile on each side of the street (5,280 feet per mile ÷ 50 feet per home = 105.6 homes per mile per side of street), or about 200 homes per mile total. 200 homes/mile × $1,500/home = $300,000 per mile. This cost does not include homeowner investment in an associated solar power system.

[22] DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, p. 131.

[23] DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC Jay Oliver Direct Testimony, September 30, 2019, pdf p. 109.

Springs, NC microgrid project as an example of Duke Energy using battery storage and solar power to substitute for building a redundant line to provide back feed capability to a vulnerable community.[24] Notably, the company filed an application for a certificate of public convenience and necessity to build the Hot Springs microgrid project.[25] However, there is no discussion in Witness Oliver's testimony as to whether the battery storage microgrid approach is less costly than building redundant lines to serve vulnerable communities, and therefore should be the preferred method of protecting these vulnerable communities.

Q. DUKE ENERGY PROPOSES CAPITAL EXPENDITURES OF $722.5 MILLION ON THE "SELF-OPTIMIZING GRID." WHAT IS A SELF-OPTIMIZING GRID?

A. Duke Energy proposes to spend $722.5 million on Self-Optimizing Grid technologies. The company states that "(Self-Optimizing Grid) capabilities are enabled by installing automated switching devices to divide circuits into switchable segments that will serve to isolate faults and automatically reroute power around trouble areas which call for expanding line and substation capacity to allow for two-way power flow and creating tie points between circuits. The IVVC (Integrated Volt/Var Control) program leverages the grid improvements from the self-optimizing technology and adds remotely-operated substation and

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[24] Duke Energy Progress, *Application for Certificate of Public Convenience and Necessity - Hot Springs Microgrid Solar and Battery Storage Facility*, Docket No. E-2, Sub 1185, October 8, 2018, p. 7. Hot Springs is a remote town of 500 people in the Appalachian Mountains served by a single distribution line that is subject to frequent outages. Duke Energy plans to install approximately 3 MW of solar power and 4 megawatt-hours (MWh) of lithium battery storage and configure circuits to allow Hot Springs to isolate from the grid as needed, known as "islanding," when grid power is unavailable.

[25] Ibid.

distribution line devices such as regulator and capacitor controllable field devices that enable a grid operator to lower voltage as a way to reduce peak demand, thereby reducing the need to generate or purchase additional power at peak prices (peak shaving) or to operate in a conservation mode during periods of more typical electricity demand in order to reduce overall energy consumption and system losses."[26] Duke Energy then makes the conclusory statement, with no evidentiary support, that the "Self-Healing Grid . . . ensures many issues on the grid can be isolated and customer impacts are limited to hundreds versus thousands."[27] This statement implies that outages will be reduced by 90 percent or more ("limited to hundreds versus thousands"), but no evidence is offered to support or clarify the meaning. In a single sentence, Duke Energy mixes talk of switching devices to isolate faults with expanding line and substation capacity to allow for two-way power flow. There is no analysis of alternatives that might achieve the same distribution grid reliability improvement at less cost to ratepayers.

Q. IS EXPANSION OF LINE AND SUBSTATION CAPACITY NECESSARY TO ENABLE TWO-WAY POWER FLOW CAUSED BY HIGH LEVELS OF DISTRIBUTED ENERGY RESOURCES (AKA ROOFTOP SOLAR)?

A. No. Installing rooftop solar with battery storage in homes and businesses can achieve the same purpose. An October 2017 study commissioned by the California Public Utilities Commission ("CPUC"), *Customer Distributed Energy*

[26] DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC Jay Oliver Direct Testimony, September 30, 2019, pp. 38-39.
[27] Ibid, p. 38.

Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis,[28] examined the degree to which grid upgrades would be necessary to absorb rooftop solar flows in neighborhoods where all homes have rooftop solar. The context of the 2017 study is the California mandate that all new residences built in 2020 or later are zero net energy homes with rooftop solar.[29] The study was in effect a "worst case" assessment of the existing grid's ability to absorb distributed solar inflows when all homes on a circuit are generating solar power and potentially exporting some or all of that solar power to the grid at the same time.

Q. IS IT YOUR POSITION THAT ADDING SOLAR AND BATTERY STORAGE AT HOMES AND BUSINESSES ACHIEVES THE SAME END WITHOUT THE POTENTIAL FOR STRANDED INVESTMENTS IN GRID OPTIMIZATION?

A Yes. Distribution circuits are typically designed to accommodate double or more of the expected peak load on the circuit.[30] The basis for this is to provide sufficient capacity to ensure each circuit can serve as a backup source of power to an adjacent circuit in case of an outage on the adjacent circuit. In this context, the 2017 California study examined rooftop solar inflows (i.e. two-way flow) up to 160 percent of the base case peak load of the distribution circuit being analyzed.

[28] DNV NL, *Customer Distributed Energy Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis*, prepared for CPUC, October 2017. "This study was conducted to inform the next CPUC net-energy metering (NEM) policy revisit (now anticipated for summer 2020)," p. vii.
[29] New York Times, *California Will Require Solar Power for New Homes*, May 9, 2018: https://www.nytimes.com/2018/05/09/business/energy-environment/california-solar-power.html.
[30] The thermal rating of the conductors determines the maximum power flow.

The study determined that simple steps, such as use of "smart" solar inverters and good distribution of the solar systems along the circuit, could substantially increase the capacity of the circuit to absorb solar inflows with little or no cost.

The 2017 study also determined that, without battery storage, incrementally more extensive grid upgrades would potentially be necessary, including regulator control upgrades, re-close blocking, reconductoring of overloaded circuit sections, and/or additional voltage regulators, to address grid reliability issues. However, the addition of battery storage with the rooftop solar would negate the need for progressively more expensive grid optimization upgrades. The report states that ". . . energy storage could be deployed to mitigate all violations on the circuit rather than deploying other measures at lower penetrations that would later become redundant."[31] In this case, Duke Energy is proposing grid optimization measures that will become redundant if battery storage is integrated with rooftop solar. The deployment of battery storage with rooftop solar systems is projected to rapidly become a standard industry practice.[32]

The 2017 study concludes its assessment of the grid reliability value of battery storage stating ". . . (battery storage) could prove much more cost-effective in the long run particularly given the other functions that are available

[31] DNV NL, *Customer Distributed Energy Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis*, prepared for CPUC, October 2017, p. xv. "This study was conducted to inform the next CPUC net-energy metering (NEM) policy revisit (now anticipated for summer 2020)," p. vii.

[32] Greentech Media, *10 Rooftop Solar and Storage Predictions for the Next Decade*, January 3, 2020: https://www.greentechmedia.com/articles/read/10-rooftop-solar-and-storage-predictions-for-the-next-decade.

from distributed energy storage systems. If energy storage was implemented at the buildings or circuits . . , then the associated integration costs identified in this study would be negated." In sum, if an appropriate capacity of battery storage is included with solar installations in neighborhoods where 100 percent of the homes have rooftop solar, no additional "grid optimization" would be necessary to the existing distribution grid.

Q. IS ANOTHER STATE EXPECTING TO ADD ABOUT 3,000 MW OF RESIDENTIAL AND COMMERCIAL BATTERY STORAGE FOR ABOUT THE SAME COST AS DUKE ENERGY'S $722.5 MILLION SELF-OPTIMIZING GRID CAPITAL BUDGET?

A. Yes. California senate bill SB 700 was signed into law in late September 2018 and is expected to add, with an incentive budget of $830 million, up to 3,000 MW of behind-the-meter residential and commercial storage in California by 2026.[33]

Q. DUKE ENERGY INDICATES THAT THE $216.7 MILLION SPENT ON IVVR WILL REDUCE DISTRIBUTION SYSTEM PEAK BY APPROXIMATELY 1.1 PERCENT.[34] $206.7 MILLION OF THIS CAPITAL BUDGET IS SLATED TO BE SPENT IN DEC SERVICE TERRITORY. IS THIS REDUCTION WORTH $206.7 MILLION?

A. No. Customer-owned solar with battery storage systems could achieve the same objective at no cost to non-solar ratepayers and at about 40 percent of the cost of

[33] Greentech Media, *California Passes Bill to Extend $800M in Incentives for Behind-the-Meter Batteries*, August 31, 2018, https://www.greentechmedia.com/articles/read/california-passes-bill-to-extend-incentives-for-behind-the-meter-batteries#gs.6cxCMs0.

[34] Duke Energy, *North Carolina Grid Improvement Plan – Pre-Read Packet for May 16, 2019 Stakeholder Meeting*, p. 13.

Duke Energy's IVVR program. The one-hour peak load in DEC service territory in 2018 was 18,935 MW.[35] A one-hour peak load reduction of 1.1 percent = 208 MW.[36] As previously noted, the cost (to customers) of a 5 kW capacity Tesla Powerwall™ under GMP's VPP program is $1,500. This equates to 5 MW capacity per $1.5 million capital investment in residential battery storage. Therefore, 208 MW × ($1.5 million/5 MW capacity) = $63 million, or about 30 percent of the IVVR program cost of $206.7 million in DEC service territory. No analysis of the residential battery storage VPP alternative to the IVVR program is included in Duke Energy's testimony.

Q. DUKE ENERGY STATES THAT THE SELF-OPTIMIZING GRID INVESTMENT WILL INCREASE CUSTOMER SOLAR CAPACITY TO 835 MW.[37] IS THE SELF-OPTIMIZING GRID NECESSARY TO ACHIEVE A CUSTOMER SOLAR CAPACITY OF 835 MW?

A. No. Duke Energy has far more than 835 MW of solar capacity on its North Carolina distribution systems with no upgrades to the distribution grid(s). The Department of Energy has sponsored numerous utility studies of the solar capacity of distribution systems. One study involved the Dominion Virginia Power (DVP) distribution system.[38] DVP evaluated 14 representative distribution feeders from an overall distribution feeder population of 1,813 in its service

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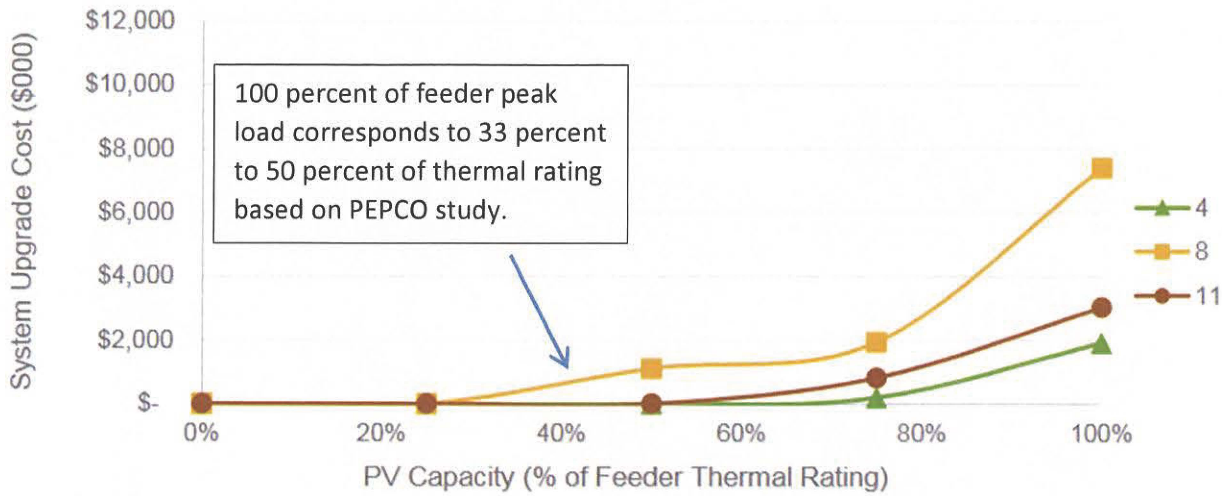
[35] DEC 2018 FERC Form 1, May 29, 2019, p. 401b. The DEC 2018 FERC Form 1 dated May 29, 2019 is publicly available and can be downloaded at https://elibrary.ferc.gov/IDMWS/search/fercgensearch.asp.
[36] 18,935 MW x 0.011 = 208 MW.
[37] Duke Energy, *North Carolina Grid Improvement Plan – Pre-Read Packet for May 16, 2019 Stakeholder Meeting*, p. 11. "SOG increases hosting capacity from approximately 496 MW to 835 MW."
[38] An affiliated company of DVP, Dominion North Carolina, is regulated by NCUC.

territory.[39] The DVP summer peak load of 15,570 MW is comparable to the 2018 DEC and DEP peak loads of 18,935 MW and 15,322 MW,[40] respectively. DVP evaluated the percentage of thermal rating of the feeder available for solar hosting as upgrades were added. This necessitates understanding the relationship between peak load on the feeder and the thermal rating of the feeder.

The feeder thermal rating, meaning the point at which overhead feeders sag excessively due to the high temperature of the conductor or at which underground feeders approach the temperature where the insulation could begin to melt, is typically 2 to 3 times the peak load on the feeder.[41] Conversely, 100 percent of peak load is approximately 33 to 50 percent of the feeder thermal rating, depending on the individual feeder. This is an important relationship to understand to interpret the DVP results. The results shown in Figure 1 are for the three feeders selected by DVP for presentation, and assume that smart solar inverters – without battery storage – are utilized to optimize voltage at the point of interconnection between the solar array and the feeder.

[39] B. Powers, *North Carolina Clean Path 2025*, August 2017, pp. 73-74, filed by NC WARN in the 2017 IRP docket, E-100, Sub 147.
[40] DEP 2018 FERC Form 1, April 12, 2019, p. 401b.
[41] Ibid., B. Powers, *North Carolina Clean Path 2025*, August 2017, Table 30a Increase in Solar Hosting Capacity and Upgrade Cost for Top 12 of 20 PEPCO Feeders Evaluated, p. 72. The 2015 PEPCO study sponsored by DOE evaluated feeder upgrades necessary to increase distribution feeder solar hosting capacity to up to 300 percent of the actual feeder peak load. See: DOE, *Model-Based Integrated High Penetration Renewables Planning and Control Analysis for PEPCO Holdings - Final Report*, December 10, 2015 (https://www.osti.gov/servlets/purl/1229729).

Figure 1. Cost Versus Improvement in Solar Hosting Capacity for Selected DVP Feeders Assuming Use of Advanced Solar Inverters
(source: Navigant)[42]



The most representative feeder among the three shown in Figure 1, in the opinion of Powers Engineering, is Feeder 11. This feeder serves a predominantly residential load, as do most of the fourteen representative feeders included in the DVP study. In contrast, Feeder 8 serves a predominantly commercial load and is representative of only about 1 percent of the 1,813 feeders in the DVP service territory. Feeder 4 is somewhat of an outlier, representing low voltage (4.16 kV) and very short (3 miles) feeders. No significant solar hosting upgrade costs are encountered on Feeder 11 until about 67 percent of the thermal rating is reached, which equates to 133 to 200 percent of feeder peak load.[43] This data implies that the Duke Energy North Carolina distribution grid, with a peak load of

[42] B. Powers, *North Carolina Clean Path 2025*, August 2017, Figure 14, p. 74, filed by NC WARN in the 2017 IRP docket, E-100, Sub 147.

[43] DOE, *Model-Based Integrated High Penetration Renewables Planning and Control Analysis for PEPCO Holdings - Final Report*, December 10, 2015 (https://www.osti.gov/servlets/purl/1229729). The 2015 PEPCO study sponsored by DOE evaluated feeder upgrades necessary to increase distribution feeder solar hosting capacity to up to 300 percent of the actual feeder peak load.

approximately 34,000 MW,[44] could meet that 34,000 MW peak load with distributed solar power – and without battery storage – with little or no upgrading. In contrast Duke Energy presumes, with no analysis, that its base case distributed solar hosting capacity without the Self-Optimizing Grid program is only 496 MW.

Q. IS THE CONSERVATIVE DEFAULT SOLAR CAPACITY OF DEC AND DEP DISTRIBUTION FEEDERS ALREADY SIX TIMES HIGHER THAN THE GIP SMART GRID OPTIMIZATION TARGET OF 835 MW?

Yes. The default rule-of-thumb for solar capacity on a distribution feeder without any need for study is 15 percent.[45] Using this rule-of-thumb, the total default "as is" solar hosting capacity of the DEC and DEP North Carolina distribution feeders is in the range of 34,000 MW × 0.15 = 5,100 MW. This is about six times higher than the stated GIP Smart Grid Optimization solar capacity goal of 835 MW. There is no justification for a Smart Grid Optimization solar capacity goal of 835 MW and any capital expense justified as necessary to achieve this goal is unreasonable.

II. NATURAL GAS FUEL CONVERSIONS AT BELEWS CREEK AND CLIFFSIDE COAL PLANTS

[44] 18,935 MW (DEC) and 15,322 MW (DEP) = 34,257 MW (non-coincident).

[45] NREL, *Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders*, July 2012, p. 1. See: https://www.nrel.gov/docs/fy12osti/55094.pdf. "A commonly used rule of thumb in the U.S. allows distributed PV systems with peak powers up to 15% of the peak load on a feeder (or section thereof) to be permitted without a detailed impact study [4]. This necessarily conservative rule has been a useful way to allow many distributed PV systems to be installed without costly and time-consuming distribution system impact studies."

Q. WHAT IS THE CAPITAL COST AND SCOPE OF THE NATURAL GAS CONVERSIONS AT BELEWS CREEK AND CLIFFSIDE COAL PLANTS?

A. DEC requests $278 million in recovery in this rate case for natural gas conversions at Belews Creek and Cliffside.[46] The 1,120 MW (each) Belews Creek Units 1 and 2[47] will be capable of burning up to 50 percent natural gas following the conversion.[48] 825 MW Cliffside Unit 6 will have the capability to burn 100 percent natural gas, 100 percent coal or a mix of the two fuels. 530 MW Cliffside Unit 5 will be able to burn a mix of coal and gas that consists of up to 40 percent gas.[49]

Q. ARE THESE BASELOAD PLANTS?

A. No. Belews Creek had a capacity factor of 41 percent in 2018.[50] Cliffside had a capacity factor of 47 percent in 2018.

Q. WHAT WAS THE PRODUCTION COST AT BELEWS CREEK AND CLIFFSIDE IN 2018?

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[46] Charlotte Business Journal, *Here's how much Duke Energy is seeking to raise utility rates in North Carolina*, September 30, 2019: https://www.bizjournals.com/charlotte/news/2019/09/30/heres-how-much-duke-energy-is-seeking-to-raise.html.

[47] DEC currently plans to complete a conversion at Unit 2 for Belews Creek which is similar to that conversion completed at Unit 1, and therefore, both Units 1 and 2 of Belews Creek will be discussed herein.

[48] Charlotte Business Journal, *Duke Energy wrapping up $65M gas co-firing project for its Cliffside coal units*, November 19, 2018: https://www.bizjournals.com/charlotte/news/2018/11/19/duke-energy-wrapping-up-65m-gas-co-firing-project.html.

[49] Ibid.

[50] DEC 2018 FERC Form 1, May 29, 2019, p. 402 and p. 403.1 (line 12). Belews Creek 2018 generation = 8,021,417 MWh. Cliffside 2018 generation = 5,554,473 MWh. Therefore, Belews Creek 2018 capacity factor = 8,021,417 MWh ÷ (8,760 hr/yr x 2,240 MW) = 0.41. Cliffside 2018 capacity factor = 5,554,473 MWh ÷ (8,760 hr/yr x 1,355 MW) = 0.47.

A. The production cost at both Belews Creek and Cliffside was approximately $40 per MWh.[51]

Q. DOES BURNING NATURAL GAS IN COAL-FIRED STEAM BOILERS FURTHER REDUCE THE ALREADY LOW THERMAL EFFICIENCY OF THE PROCESS?

A. Yes. Burning natural gas in steam boilers formerly fired on coal reduces the thermal efficiency of the steam boiler combustion process by 3 to 5 percent.[52] The coal-fired steam boiler is already a relatively low efficiency power generation process compared to a combined cycle power plant.[53]

Q. WHAT IS THE PRODUCTION COST OF COMBINED CYCLE UNIT?

A. About $31/MWh,[54] or about 25 percent less than the production cost at Belews Creek or Cliffside.

Q. WHAT IS THE PRODUCTION COST OF HYDROELECTRIC UNITS?

A. About $13/MWh, or about one-third the production cost at Belews Creek or Cliffside.[55]

Q. ARE EXISTING REGIONAL MERCHANT COMBINED CYCLE AND HYDROELECTRIC PLANTS AVAILABLE TO SUPPLY DUKE ENERGY WITH LOWER-COST POWER THAN POWER FROM BELEWS CREEK AND CLIFFSIDE?

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[51] Ibid, p. 402 and p. 403.1 (line 35).
[52] Power Engineering, *De-Bunking the Myths of Coal-to-Gas Conversions*, Issue 11 and Volume 119, December 2, 2015. See: https://www.power-eng.com/2015/12/02/de-bunking-the-myths-of-coal-to-gas-conversions/#gref.
[53] 2018 DEC FERC Form 1, May 29, 2019, p. 402 (Belews Creek heat rate = 9,424 Btu/kWh), p. 403.1, (Cliffside heat rate = 9,241 Btu/kWh), p. 403.3 (Buck combined cycle plant heat rate = 7,160 Btu/kWh).
[54] Ibid, p. 403.3 (Buck combined cycle plant, 698 MW, expenses per net kWh = $0.0311/kWh – line 35).
[55] Ibid, p. 406.1 (Cowans Ford hydro plant, 350 MW, expenses per net kWh = $0.0129/kWh – line 35).

A. Yes. I addressed this issue in July 2016 in DOCKET NO. E-2, SUB 1089, Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a 752 MW Natural Gas-Fueled Electric Generation Facility in Buncombe County Near the City of Asheville.[56] The affidavit filed by NC WARN on my behalf in DOCKET NO. E-2, SUB 1089, which affidavit is both accurate and pertinent today, stated that "DEP West has available off-the-shelf hydropower and combined cycle gas turbine options in the region to supply capacity if additional capacity is needed . . . Four Smoky Mountain Hydro units near the North Carolina-Tennessee border have a capacity of 378 MW and produce 1.4 million MWh annually. These units are in the TVA system, which is connected to DEP West by a single 161 KV line from TVA to the substation at the Walters Hydro Plant in DEP West. The power produced by these units is not currently contracted for purchase. . . The underutilized merchant 523 MW Columbia Energy combined cycle plant outside of Columbia, SC, built more than a decade ago when the capital cost of combined cycle power construction was lower than it is today, could serve some or all of any need that might arise." These are examples of lower-cost regional power supplies that could have been contracted in 2016 to avoid substantial Duke Energy capital expenditures on new generation. The same approach should have been used to assess the reasonableness of natural gas conversions at Belews Creek and

[56] DOCKET NO. E-2, SUB 1089 - Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a 752 MW Natural Gas-Fueled Electric Generation Facility in Buncombe County Near the City of Asheville, *Affidavit of William E. Powers for NC WARN and The Climate Times*, June 27, 2016.

Cliffside. There is currently nearly 50,000 MW of low-cost merchant combined cycle capacity in the PJM regional market,[57] adjacent to Duke Energy North Carolina territory, potentially available for contracting by Duke Energy to substitute for higher cost production from Belews Creek and Cliffside.[58] Relying on existing regional lower cost gas and/or hydroelectric resources would have saved Duke Energy ratepayers money and potentially facilitated the permanent shutdown of Belews Creek and Cliffside.

Q. ARE SOLAR WITH BATTERY STORAGE PROJECTS ALREADY CAPABLE OF PRODUCING POWER FOR LESS THAN THE $40/MWH PRODUCTION COST AT BELEWS CREEK AND CLIFFSIDE?

A. Yes. Los Angeles Department of Water and Power signed a 25-year contract for the 375 MW Eland solar and battery storage project in September 2019 for just under $40/MWh.[59] The project includes four hours of battery storage at rated capacity.[60] The cost of battery storage capacity continues to decline at a rapid rate.[61]

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[57] Monitoring Analytics, LLC, *2019 Quarterly State of the Market Report for PJM: January through March*, May 9, 2019, p. 65. See: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019q1-som-pjm.pdf. As of March 31, 2019, there was 47,591.6 MW of operational combined cycle capacity in PJM.

[58] U.S. Energy Information Administration, *Natural gas-fired power plants are being added and used more in PJM Interconnection*, October 17, 2018. See: https://www.eia.gov/todayinenergy/detail.php?id=37293. Combined cycle units in PJM generated about 200 million MWh in 2017, at an average capacity factor of about 60 percent.

[59] PV Magazine USA, *Los Angeles says "Yes" to the cheapest solar plus storage in the USA*, September 10, 2019. See: https://pv-magazine-usa.com/2019/09/10/los-angeles-commission-says-yes-to-cheapest-solar-plus-storage-in-the-usa/.

[60] Ibid.

[61] CNBC, *The battery decade: How energy storage could revolutionize industries in the next 10 years*, December 30, 2019. See: https://www.cnbc.com/2019/12/30/battery-developments-in-the-last-decade-created-a-seismic-shift-that-will-play-out-in-the-next-10-years.html.

Q. COULD THE ADDITION OF BATTERY STORAGE TO THE NEARLY 6,000 MW OF UTILITY-SCALE SOLAR IN NORTH CAROLINA ACHIEVE THE SAME OBJECTIVE AS ADDING GAS-FIRING CAPABILITY AT THE BELEWS CREEK AND CLIFFSIDE COAL PLANTS?

A. Yes. This approach could be used on the nearly 6,000 MW of solar farms in North Carolina[62] to smooth-out solar generation and provide dispatchable peaking power.

Q. WOULD THIS APPROACH IMPOSE ANY CAPITAL COST BURDEN ON DUKE ENERGY RATEPAYERS?

A. No. The cost of battery storage additions would be borne by the third-party owners of the solar facilities. However, Duke Energy has opposed allowing solar facility owners to add battery storage. As noted by NCSEA Witness Tyler Harris, "Duke Energy is proposing unjust and unreasonable barriers to market entry for energy storage resources – particularly with respect to power purchase terms and conditions and interconnection standards – that will wholly obstruct the addition of such resources to the vast majority of installed renewable generating facilities in North Carolina."[63] Duke Energy has spent $278 million on natural gas conversions at Belews Creek and Cliffside that could have been avoided – and Belews Creek and Cliffside potentially mothballed – by simply allowing existing

[62] Solar Energy Industries Association, *State Solar Spotlight: North Carolina*, at https://www.seia.org/sites/default/files/2019-12/North%20Carolina.pdf.
[63] Docket No. E-100, Sub 158, Direct Testimony of Tyler H. Norris on behalf of NCSEA, July 3, 2019, p. 8.

solar facilities in North Carolina to add battery storage at their own expense in return for reasonable payment for the added value of the storage capacity. For all of these reasons, the said expenditures at Belews Creek and Cliffside were neither reasonable nor prudent, and DEC's cost recovery requests at those facilities should therefore be denied.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document upon counsel for all parties to this docket by email transmission.

This the 18th day of February, 2020.

Matthew D. Quinn
N.C. Bar No. 40004
Lewis & Roberts, PLLC
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Raleigh, North Carolina 27612
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Facsimile: 919-981-0199

Attorney for NC WARN

MR. JENKINS: Madam Chair, Alan Jenkins --

CHAIR MITCHELL: You may proceed, Mr. Jenkins.

MR. JENKINS: -- similar motion.

CHAIR MITCHELL: Proceed, please.

MR. JENKINS: All parties have waived cross examination of Commercial Group witness Steve W. Chriss. I hereby ask to copy into the record his direct testimony consisting of 18 pages with an Appendix A, Experience, and four exhibits premarked as Chriss Exhibits 1 through 4.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Mr. Jenkins, it will be allowed.

MR. JENKINS: Thank you.

(Whereupon, the prefiled direct testimony of Steve W. Chriss and Appendix A were copied into the record as if given orally from the stand.)

(Whereupon, Chriss Exhibits 1 through 4 were admitted into evidence.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable To Electric Service in North Carolina	)	**Docket No. E-7, Sub 1214**

Direct Testimony

of

Steve W. Chriss

On Behalf of the Commercial Group

February 18, 2020

Table of Contents

Exhibits

Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND WORK POSITION.

A. My name is Steve W. Chriss. My business address is 2608 SE J St., Bentonville, AR 72712-5530. My title is Director, Energy Services, for Walmart Inc.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. In 2001, I completed a Master of Science in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings. I was promoted to Senior Manager, Energy Regulatory Analysis, in June 2011. I was promoted to my current position in October, 2016 and the position was re-titled in October, 2018. My Witness Qualifications Statement is included herein as Appendix A.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("NCUC" OR "COMMISSION")?

A. Yes, in the Duke Energy/Progress Energy Merger proceeding, Docket E-2, Sub 998/E-7, Sub 986, and the rate cases of Duke Energy Carolinas, Docket No. E-7, Sub 989, Docket No. E-7, Sub 1026, and Docket No. E-7, Sub 1146, and Duke Energy Progress, Docket No. E-2, Sub 1023 and Docket No. E-2, Sub 1142.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of the Commercial Group, an ad hoc group of commercial customers of Duke Energy Carolinas, LLC (the "Company" or "DEC"). In this proceeding, the Commercial Group is composed of BJ's Wholesale Club, Inc., Food Lion, LLC, Ingles Markets, Inc., JC Penney Corp., Inc., Macy's Inc., and Walmart Inc.

Q. HAVE YOU PREPARED ANY EXHIBITS?

A. Yes. We have prepared the exhibits listed in the table of contents.

Purpose of Testimony and Recommendations

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this testimony, I present the Commercial Group's general concerns regarding the Company's proposed revenue requirement, cost of service and revenue allocation, meter data access, and the positive impact Commercial Group members have on the State of North Carolina.

Q. WHAT IMPACTS DO THE COMPANIES IN THE COMMERCIAL GROUP HAVE ON THE NORTH CAROLINA ECONOMY?

A. The companies in the Commercial Group have a significant positive impact on the North Carolina economy. My understanding is that two of the top three, and three of the top fourteen, private employers in the state are members of the Commercial Group, according to the latest information published on the North Carolina

Department of Commerce web site.[1] Both Food Lion and Ingles have their headquarters in North Carolina.

Q. AS AN EXAMPLE, PLEASE DESCRIBE WALMART'S OPERATIONS IN NORTH CAROLINA.

A. As shown on Walmart's website, as of October 2019, Walmart had 220 retail facilities and distribution centers, and over 59,000 associates in North Carolina.[2] Per the North Carolina Department of Commerce web site cited above, Walmart is the largest private employer in the state.

Q. HAS COMMERCIAL GROUP COUNSEL PROVIDED YOU WITH INFORMATION ON THE NORTH CAROLINA OPERATIONS OF THE OTHER COMMERCIAL GROUP MEMBERS?

A. Yes. Food Lion has approximately 500 facilities and employs approximately 34,000 employees in North Carolina and is listed as the third largest private employer in the state. Ingles employs over 10,000 employees in North Carolina, making Ingles the 14th largest private employer in North Carolina. In all, members of the Commercial Group directly employ well over 100,000 North Carolina workers and supports the employment of over 100,000 other North Carolina workers through the billions of dollars members of the Commercial Group spend for merchandise and services in the state each year.

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[1] https://files.nc.gov/nccommerce/documents/LEAD/Top-Employers/Top_300_Employers_Manufacturing_and_Nonmanufacturing_2019_Corrected.pdf
[2] *See* http://corporate.walmart.com/our-story/locations/united-states#/united-states/north-carolina

Q. GENERALLY, WHY ARE UTILITY CUSTOMERS, INCLUDING RETAILERS AND OTHER COMMERCIAL CUSTOMERS, CONCERNED ABOUT DEC'S PROPOSED RATE INCREASE?

A. Electricity represents a significant portion of retailers' operating costs. When rates increase, that increase in cost to retailers puts pressure on consumer prices and on the other expenses required by a business to operate, which impacts retailers' customers and employees. Rate increases also directly impact retailers' customers, who are DEC's residential and small business customers. Given current economic conditions, a rate increase is a serious concern for retailers and their customers, and the Commission should consider these impacts thoroughly and carefully in ensuring that any increase in DEC's rates is only the minimum amount necessary for the utility to provide adequate and reliable service.

Q. PLEASE SUMMARIZE THE COMMERCIAL GROUP'S RECOMMENDATIONS TO THE COMMISSION.

A. The Commercial Group's recommendations to the Commission are as follows:

1) The Commission should closely examine the Company's proposed revenue requirement increase and the associated proposed increase in ROE, especially when viewed in light of: (1) the customer impact of the resulting revenue requirement increase as discussed above; (2) recent rate case ROEs approved by the Commission; and (3) recent rate case ROEs approved by commissions nationwide.

2) The Commercial Group does not take a position on the Company's proposed cost of service model at this time. However, to the extent that

alternative cost of service models or modifications to the Company's model are proposed by other parties, the Commercial Group reserves the right to address such changes in accordance with the Commission's procedures in this docket.

3) The Commercial Group does not oppose the Company's proposed revenue allocation at the Company's proposed revenue requirement. If the Commission determines that the appropriate revenue requirement is less than that proposed by the Company, the Commission should use the reduction in revenue requirement to move each customer class closer to its respective cost of service while ensuring that all classes see a reduction from DEC's initially proposed increases.

4) In addition to supporting Green Button "Download My Data" ("DMD") functionality, the Commission should require DEC to include Green Button "Connect My Data" ("CMD") functionality as part of its roll-out of customer access to their data.

Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY THE COMPANY INDICATE WALMART'S SUPPORT?

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any filed position.

Revenue Requirement and Return on Equity

Q. WHAT REVENUE REQUIREMENT INCREASE HAS THE COMPANY PROPOSED IN ITS FILING?

A. The Company has proposed a total base rate revenue requirement increase of approximately $445 million, based on the test year ending December 31, 2018. *See* McManeus Exhibit 1, page 1.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S OPERATING INCOME BEFORE THE PROPOSED INCREASE?

A. My understanding is that the Company's filed operating income before the proposed increase is approximately $835 million. *See* McManeus Exhibit 1, page 1.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED OPERATING INCOME?

A. My understanding is that the Company filed a proposed operating income of $1,175 million. *See* McManeus Exhibit 1, page 1.

Q. WHAT PERCENT INCREASE IN OPERATING INCOME IS THE COMPANY REQUESTING?

A. The Company is requesting an increase in its operating income of approximately 40.7 percent. *See* Chriss Exhibit 1.

Q. WHAT IS THE COMPANY'S PROPOSED ROE IN THIS DOCKET?

A. The Company presents testimony to support a ROE of 10.5 percent, based on a range of 10.0 percent to 11.0 percent. *See* Direct Testimony of Robert B. Hevert, page 3, line 18 to page 4, line 1. However, the Company's proposed ROE is 10.3

percent, which they present to the Commission as a "rate mitigation measure." *See* Direct Testimony of Karl W. Newlin, page 7, line 11 to line 14. The requested ROE at the Company's proposed capital structure of 53 percent equity results in a proposed overall rate of return of 7.58 percent. *See* McManeus Exhibit 1, page 1 and page 2.

Q. WHAT ARE THE CURRENTLY APPROVED ROE AND EQUITY RATIO FOR DEC?

A. The currently effective ROE approved by the Commission for DEC is 9.9 percent and the currently effective equity ratio is 52 percent. *See* Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146, page 32 and page 63.

Q. IS THE COMMERCIAL GROUP CONCERNED THAT THE COMPANY'S PROPOSED ROE AND OPERATING INCOME INCREASE ARE EXCESSIVE?

A. The Commercial Group is concerned that the Company's proposed ROE of 10.3 percent and operating income increase of 40.7 percent are excessive, especially in light of: (1) the customer impact of the resulting revenue requirement increase as discussed above; (2) recent rate case ROEs approved by the Commission; and (3) recent rate case ROEs approved by commissions nationwide.

Customer Impact of the Proposed Increase in ROE

Q. **WHAT IS THE REVENUE REQUIREMENT IMPACT OF THE COMPANY'S PROPOSED INCREASE IN ROE AND EQUITY RATIO?**

A. Using the Company's proposed cost of debt, the revenue requirement impact of the Company's proposed increases in ROE and equity ratio from those approved in Docket No. E-7, Sub 1146 is approximately $54 million, or approximately 12 percent of the Company's proposed revenue requirement increase. *See* Chriss Exhibit 2.

Recent ROEs Approved by the Commission

Q. IS THE COMPANY'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN THE ROES APPROVED BY THE COMMISSION FROM 2016 TO PRESENT?

A. Yes. During this time period the Commission has issued orders with stated ROEs in three dockets, including the DEC rate case noted above, with the average of the ROEs approved equal to 9.9 percent. *See* Chriss Exhibit 3.

Q. IN WHICH OTHER DOCKETS DID THE COMMISSION ISSUE ORDERS WITH STATED ROES?

A. The Commission issued orders with stated ROEs in the following dockets:

- Docket No. E-22, Sub 532, the Virginia Electric & Power Company general rate case, in which the Commission approved an ROE of 9.9. *See* Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Docket No. E-22, Sub 532, page 81.
- Docket No. E-2, Sub 1142, Duke Energy Progress Inc. general rate case, in which the Commission approved an ROE of 9.9 percent. *See* Order Accepting Stipulation, Deciding Contested Issues and Granting Partial

Rate Increase, Docket No. E-2, Sub 1142, page 56.

As such, the Company's proposed 10.3 percent ROE is counter to recent Commission actions regarding ROE.

National Utility Industry ROE Trends

Q. IS THE COMPANY'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN THE ROES APPROVED BY OTHER UTILITY REGULATORY COMMISSIONS IN 2016, 2017, 2018, 2019, AND SO FAR IN 2020?

A. Yes. According to data from S&P Global Market Intelligence, a financial news and reporting company, the average of the 148 reported electric utility rate case ROEs authorized by commissions to investor-owned utilities in 2016, 2017, 2018, 2019, and so far in 2020, is 9.61 percent. The range of reported authorized ROEs for the period is 8.4 percent to 11.95 percent, and the median authorized ROE is 9.6 percent. The average and median values are significantly below the Company's proposed ROE of 10.3 percent. *See* Chriss Exhibit 3. As such, the Company's proposed 10.3 percent ROE is counter to broader electric industry trends.

Q. SEVERAL OF THE REPORTED AUTHORIZED ROES ARE FOR DISTRIBUTION-ONLY UTILITIES OR FOR ONLY A UTILITY'S DISTRIBUTION SERVICE RATES. WHAT IS THE AVERAGE AUTHORIZED ROE IN THE REPORTED GROUP FOR VERTICALLY INTEGRATED UTILITIES?

A. In the group reported by S&P Global, the average ROE for vertically integrated utilities authorized from 2016 through present is 9.75 percent, and the trend in these averages has been relatively stable. The average ROE authorized for vertically integrated utilities in 2016 was 9.77 percent; in 2017 it was 9.80 percent; in 2018 it was 9.68 percent; in 2019 it was 9.73 percent; and thus far in 2020 it was 9.74 percent. *Id.* As such, the Company's proposed 10.3 percent ROE is counter to broader electric industry trends and, in fact, as shown in Figure 1, would be equal to the fourth highest approved ROE for a vertically integrated utility from 2016 to present if approved by the Commission.

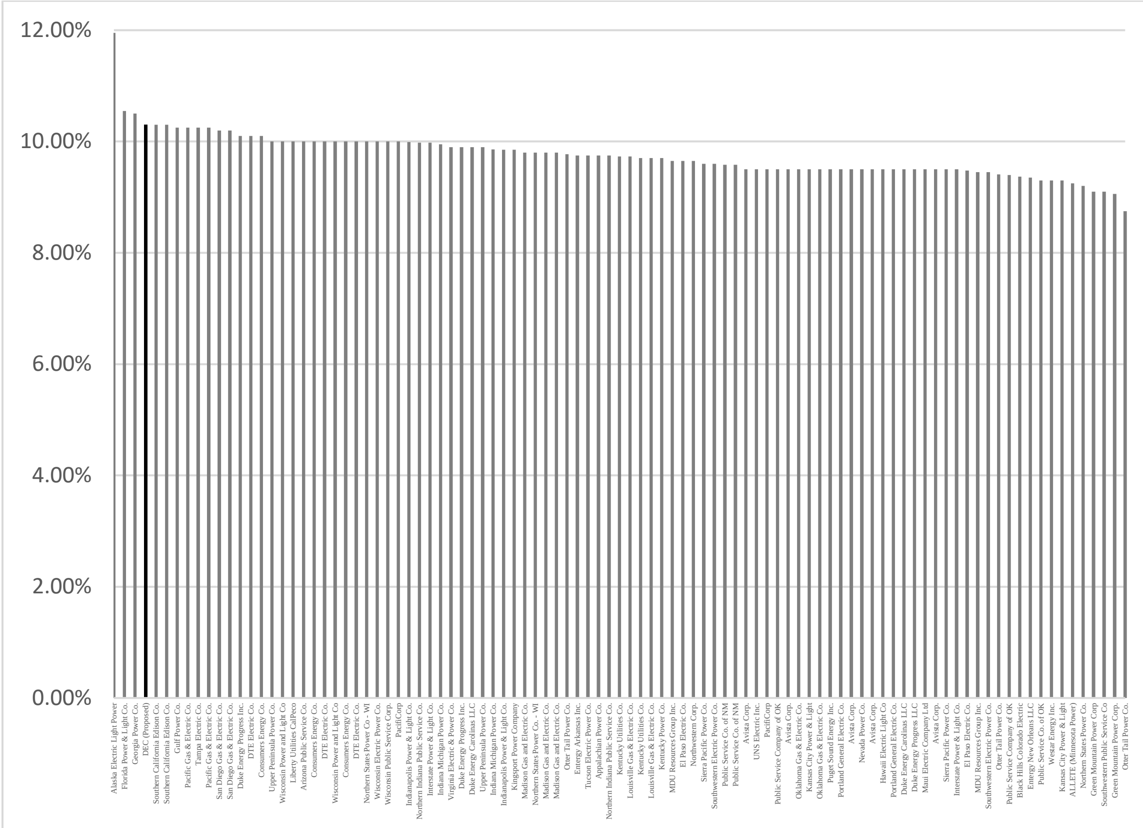

Figure 1. DEC Proposed ROE Versus Authorized ROEs for Vertically Integrated Utilities, 2016 to present. Source: Commercial Group Exhibit CR-3.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT IF THE COMMISSION WERE TO AWARD AN ROE OF 9.75 PERCENT, THE AVERAGE ROE AWARDED FOR VERTICALLY INTEGRATED UTILITIES FROM 2016 TO PRESENT?

A. Assuming the Company's proposed cost of debt and equity ratio, authorizing DEC an ROE of 9.75 percent instead of the requested 10.3 percent would result in a reduction to the requested base revenue requirement increase, inclusive of taxes, of about \$59.2 million. This represents about a 13.3 percent reduction of the Company's requested base revenue requirement increase. *See* Chriss Exhibit 4.

Q. IS THE COMMERCIAL GROUP RECOMMENDING THAT THE COMMISSION BE BOUND BY ROEs AUTHORIZED BY OTHER STATE REGULATORY AGENCIES?

A. No. Decisions of other state regulatory commissions are not binding on the Commission. Additionally, each commission considers the specific circumstances in each case in its determination of the proper ROE. The Commercial Group is providing this information to illustrate a national customer perspective on industry trends in authorized ROE. In addition to using recent authorized ROEs as a general gauge of reasonableness for the various cost-of-equity analyses presented in this case, the Commission should consider how its authorized ROE impacts customers relative to other jurisdictions.

Conclusion

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION IN REGARDS TO THE COMPANY'S PROPOSED ROE?

A. The Commission should closely examine the Company's proposed revenue requirement increase and the associated proposed increase in ROE, especially when viewed in light of: (1) the customer impact of the resulting revenue requirement increase as discussed above; (2) recent rate case ROEs approved by the Commission; and (3) recent rate case ROEs approved by commissions nationwide.

Cost of Service and Revenue Allocation

Q. WHAT IS THE COMMERCIAL GROUP'S POSITION ON SETTING RATES BASED ON THE UTILITY'S COST OF SERVICE?

A. The Commercial Group advocates that rates be set based on the utility's cost of service for each rate class. This produces equitable rates that reflect cost causation, send proper price signals, and minimize price distortions.

Q. DOES THE COMMERCIAL GROUP TAKE A POSITION ON THE COMPANY'S PROPOSED COST OF SERVICE MODEL AT THIS TIME?

A. No. However, to the extent that alternative cost of service models or modifications to the Company's model are proposed by other parties, the Commercial Group reserves the right to address any such changes in accordance with the Commission's procedures in this docket.

Q. HOW DOES THE COMPANY REPRESENT WHETHER RATES FOR A CUSTOMER CLASS ACCURATELY REFLECT THE UNDERLYING COST CAUSATION?

A. The Company represents this relationship in their cost of service results through the use of class-specific rates of return. These rates of return can be converted into unitized rates of return ("UROR"), which is an indexed measure of the relationship of the rate of return for an individual rate class to the total system rate of return. A UROR greater than 1.0 means that the rate class is paying rates in excess of the costs incurred to serve that class, and a UROR less than 1.0 means that the rate class is paying rates less than the costs incurred to serve that class.

As such, those rate classes with a UROR greater than 1.0 shoulder some of the revenue responsibility burden for the classes with a UROR less than 1.0.

Q. HAVE YOU CALCULATED A UROR FOR EACH MAJOR CUSTOMER CLASS BASED ON THE COMPANY'S COST OF SERVICE RESULTS?

A. Yes, as shown in Table 1 below:

Table 1. Unitized Rates of Return, Existing Rates, DEC Proposed Cost of Service Study Results.

Customer Class	Rate of Return (%)	UROR
RS	5.2	0.96
GS	6.8	1.26
LT	3.9	0.72
I	8.3	1.53
OPT-V	4.7	0.87
Total Company	**5.4**	**1.00**

Source: Pirro Exhibit 4, Page 1

It should be noted that the rates for a number of the OPT-V subclasses are much closer to cost of service levels than indicated by Table 1. The URORs for OPT-V Secondary Small, Secondary Medium, Primary Medium, and Transmission are between 0.96 and 1.04. *See* Pirro Exhibit 4, Page 1.

Q. WHAT REVENUE ALLOCATION METHODOLOGY DOES THE COMPANY PROPOSE?

A. My understanding is that DEC proposes to allocate revenue on the basis of rate base, with the goal of moving each class's deficiency or surplus to a band of +/- 10 percent if possible. *See* Direct Testimony of Michael J. Pirro, page 11, line 9 to line 13.

Q. WHAT IS THE COMMERCIAL GROUP'S REVENUE ALLOCATION RECOMMENDATION TO THE COMMISSION AT THE COMPANY'S PROPOSED REVENUE REQUIREMENT?

A. The Commercial Group does not oppose the Company's proposed revenue allocation at the Company's proposed revenue requirement.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION IF IT DETERMINES THAT A LOWER REVENUE REQUIREMENT IS APPROPRIATE?

A. If the Commission determines that the appropriate revenue requirement is less than that proposed by the Company, the Commission should use the reduction in revenue requirement to move each customer class closer to its respective cost of service while ensuring that all classes see a reduction from DEC's initially proposed increases.

Advanced Metering Infrastructure

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S AMI PROPOSAL IN THIS DOCKET?

A. My understanding is that the Company proposes to include costs of AMI implementation in this rate case. DEC also discusses its plans to roll-out the Green Button DMD standard for customers to access their usage data. *See* Direct Testimony of Donald L. Schneider, Jr., page 7, line 3 to line 7 and page 8, line 9 to line 15.

Q. WHAT DOES IT MEAN TO BE GREEN BUTTON COMPATIBLE?

A. Green Button is a mechanism through which utility customers can access their energy usage information in a "consumer-friendly and computer-friendly format."[3] Essentially, it allows a customer to simply click a "Green Button" located on a utility's website and download their usage information. The Green Button initiative was developed by the federal government to challenge utilities to provide customers with energy usage information in a downloadable, standard, and simple format.[4]

Q. WHY IS ACCESS TO INTERVAL ENERGY USAGE DATA IMPORTANT TO CUSTOMERS?

A. Quite simply, easy and transparent access to interval data allows a customer to measure its energy usage in smaller increments, make tailored adjustments to its energy consumption in response to the data, and reduce their bills.

Q. DOES THE COMMERCIAL GROUP TAKE A POSITION ON THE RECOVERY OF AMI COSTS AS PART OF THIS CASE?

A. No.

Q. DOES THE COMMERCIAL GROUP OPPOSE THE COMPANY'S EFFORTS TO ENABLE DMD?

A. The Commercial Group does not generally oppose the Company's proposal to enable DMD. However, the Commercial Group believes that additional measures are necessary to address the specific needs of large multi-site customers who have multiple facilities within a utility's territory.

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[3] www.greenbuttondata.org
[4] www.greenbuttonalliance.org/about#what.

Q. PLEASE EXPLAIN.

A. Ideally, Commercial Group members would be able to obtain its interval data for all of its locations through a single download, or to allow a customer-authorized third-party vendor to obtain that data through an automated process.

Q. DOES DMD TYPICALLY ALLOW A CUSTOMER TO ACCESS ITS INTERVAL DATA FOR ALL OF ITS LOCATIONS FROM THE COMPANY'S CURRENT CUSTOMER PORTAL THROUGH A SINGLE DOWNLOAD?

A. To the best of the Commercial Group's knowledge, no. For large multi-site customers with several facilities, each with their own account, data is typically only accessed for one account at a time, requiring an individual download per account. For example, if Walmart wants to retrieve its energy usage data for each of its accounts located in DEC's service territory, it would need to download over 100 individual datafiles.

Q. WHAT DOES THE COMMERCIAL GROUP RECOMMEND TO THE COMMISSION TO ADDRESS THIS CONCERN WITH DMD?

A. The Commercial Group recommends that, in addition to supporting DMD, the Commission should require DEC to include the Green Button CMD functionality as part of its roll-out of customer access to their data. CMD allows a customer or a customer-authorized third party to download data automatically through an application programming interface ("API").[5]

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[5] An API essentially allows applications to communicate with each other, i.e., a utility-side application can communicate and share data with a consumer-side application.

Q. WHAT DOES THE COMMERCIAL GROUP BELIEVE IS THE BENEFIT OF CMD?

A. CMD provides simplified data access for large, multi-site customers. Under DMD functionality, only the customer can access interval data. In contrast, CMD functionality allows application developers and third-parties to access customer usage information (with customer permission) through an automated process while maintaining security and privacy. For example, Walmart currently engages a third-party vendor to ingest interval energy usage data for its stores, distribution centers, and other facilities serviced by other utilities across the United States. In essence, where a customer utilizes the services of an application or other vendor to assist in analyzing its energy usage, CMD capability cuts out the middleman -- the customer -- and allows the vendor to directly access the data. Thus, the CMD process is more efficient for large multi-site customers like Walmart.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

Steve W. Chriss
Walmart Inc.
Business Address: 2608 SE J Street, Bentonville, AR, 72716-5530

EXPERIENCE

July 2007 – Present
Walmart Inc., Bentonville, AR
Director, Energy Services (October 2018 – Present)
Director, Energy and Strategy Analysis (October 2016 – October 2018)
Senior Manager, Energy Regulatory Analysis (June 2011 – October 2016)
Manager, State Rate Proceedings (July 2007 – June 2011)

June 2003 – July 2007
Public Utility Commission of Oregon, Salem, OR
Senior Utility Analyst (February 2006 – July 2007)
Economist (June 2003 – February 2006)

January 2003 - May 2003
North Harris College, Houston, TX
Adjunct Instructor, Microeconomics

June 2001 - March 2003
Econ One Research, Inc., Houston, TX
Senior Analyst (October 2002 – March 2003)
Analyst (June 2001 – October 2002)

EDUCATION

2001	**Louisiana State University**	M.S., Agricultural Economics
1997-1998	**University of Florida**	Graduate Coursework, Agricultural Education and Communication
1997	**Texas A&M University**	B.S., Agricultural Development B.S., Horticulture

PRESENT MEMBERSHIPS

Arizona Independent Scheduling Administrators Association, Board
Arizonans for Electric Choice & Competition, Chairman
Edison Electric Institute National Key Accounts Program, Customer Advisory Group
Renewable Energy Buyers Alliance, Advisory Board

PAST MEMBERSHIPS

Southwest Power Pool, Corporate Governance Committee, 2019

TESTIMONY BEFORE REGULATORY COMMISSIONS

2020

Texas Docket No. 49831: Application of Southwestern Public Service Company for Authority to Change Rates.

2019
Missouri Case No. ER-2019-0335: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease its Revenues for Electric Service.

Michigan Case No. U-20561: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

Indiana Cause No. 45253: Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code §§ 8-1-2-42.7 and 8-1-2-61, For (1) Authority to Modify its Rates and Charges for Electric Utility Service Through a Step-In of New Rates and Charges Using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code § 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customer Classes.

Arizona Docket No. E-01933A-19-0228: In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to its Operations Throughout the State of Arizona and for Related Approvals.

Georgia Docket No. 42516: In Re: Georgia Power's 2019 Rate Case.

Colorado Proceeding No. 19AL-0268E: Re: In the Matter of Advice No. 1797-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8-Electric Tariff to Implement Rate Changes Effective on Thirty Days' Notice.

New York Case No. 19-E-0378: Proceeding on the Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Case No. 19-E-0380: Proceeding on the Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

Maryland Case No. 9610: In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates.

Nevada Docket No. 19-06002: In the Matter of the Application by Sierra Pacific Power Company, D/B/A NV Energy, Filed Pursuant to NRS 704.110(3) and NRS 704.110(4), Addressing its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers.

Florida Docket No. 20190061-EI: In Re: Petition of Florida Power & Light Company for Approval of FPL SolarTogether Program and Tariff.

Wisconsin Docket No. 6690-UR-126: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates – Test Year 2020.

Wisconsin Docket No. 5-UR-109: Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates – Test Year 2020.

New Mexico Case No. 19-00158-UT: In the Matter of the Application of Public Service Company of New Mexico for Approval of PNM Solar Direct Voluntary Renewable Energy Program, Power Purchase Agreement, and Advice Notice Nos. 560 and 561.

Indiana Cause No. 45235: Petition of Indiana Michigan Power Company, and Indiana Corporation, for Authority to Increase its Rates and Charges for Electric Utility Service through a Phase In Rate Adjustment; and for Approval of Related Relief Including: (1) Revised Depreciation Rates; (2) Accounting Relief; (3) Inclusion in Rate Base of Qualified Pollution Control Property and Clean Energy Project; (4) Enhancements to the Dry Sorbent Injection System; (5) Advanced Metering Infrastructure; (6) Rate Adjustment Mechanism Proposals; and (7) New Schedules of Rates, Rules and Regulations.

Iowa Docket No. RPU-2019-0001: In Re: Interstate Power and Light Company.

Texas Docket No. 49494: Application of AEP Texas Inc. for Authority to Change Rates.

Arkansas Docket No. 19-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Virginia Case No. PUR-2019-00050: Application of Virginia Electric and Power Company for Determination of the Fair Rate of Return on Common Equity Pursuant to § 56-585.1:1 of the Code of Virginia.

Indiana Docket No. 45159: Petition of Northern Indiana Public Service Company LLC Pursuant to Indiana Code §§ 8-1-2-42.7, 8-1-2-61 and Indiana Code §§ 1-2.5-6 for (1) Authority to Modify its Rates and Charges for Electric Utility Service Through a Phase In of Rates; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief; and (5) Approval of a New Service Structure for Industrial Rates.

Texas Docket No. 49421: Application of Centerpoint Energy Houston Electric, LLC for Authority to Change Rates.

Nevada Docket No. 18-11015: Re: Application of Nevada Power Company d/b/a NV Energy, Filed Under Advice No. 491, to Implement NV Greenenergy 2.0 Rider Schedule No. NGR 2.0 to Allow Eligible Commercial Bundled Service Customers to Voluntarily Contract with the Utility to Increase Their Use of Reliance on Renewable Energy at Current Market-Based Fixed Prices.

Nevada Docket No. 18-11016: Re: Application of Sierra Pacific Power Company d/b/a NV Energy, Filed Under Advice No. 614-E, to Implement NV Greenenergy 2.0 Rider Schedule No. NGR 2.0 to Allow Eligible Commercial Bundled Service Customers to Voluntarily Contract with the Utility to Increase Their Use of Reliance on Renewable Energy at Current Market-Based Fixed Prices.

Georgia Docket No. 42310: In Re: Georgia Power Company's 2019 Integrated Resource Plan and Application for Certification of Capacity From Plant Scherer Unit 3 and Plant Goat Rock Units 9-12 and Application for Decertification of Plant Hammond Units 1-4, Plant Mcintosh Unit 1, Plant Langdale Units 5-6, Plant Riverview Units 1-2, and Plant Estatoah Unit 1.

Wyoming Docket Nos. 20003-177-ET-18: In the Matter of the Application of Cheyenne Light, Fuel and Power Company D/B/A Black Hills Energy For Approval to Implement a Renewable Ready Service Tariff.

South Carolina Docket No. 2018-318-E: In the Matter of the Application of Duke Energy Progress, LLC For Adjustments in Electric Rate Schedules and Tariffs.

Montana Docket No. D2018.2.12: Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.

Louisiana Docket No. U-35019: In Re: Application of Entergy Louisiana, LLC for Authorization to Make Available Experimental Renewable Option and Rate Schedule ERO.

Arkansas Docket No. 18-037-TF: In the Matter of the Petition of Entergy Arkansas, Inc. For Its Solar Energy Purchase Option.

2018
South Carolina Docket No. 2017-370-E: Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc., for Review and Approval of a Proposed Business Combination Between SCANA Corporation and Dominion Energy, Inc., as may be Required, and for a Prudency Determination Regarding the Abandonment of the V.C. Summer Units 2 & 3 Project and Associated Customer Benefits and Cost Recovery Plans.

Kansas Docket No. 18-KCPE-480-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Virginia Case No. PUR-2017-00173: Petition of Wal-Mart Stores East, LP and Sam's East, Inc. for Permission to Aggregate or Combine Demands of Two or More Individual Nonresidential Retail Customers of Electric Energy Pursuant to § 56-577 A 4 of the Code of Virginia.

Virginia Case No. PUR-2017-00174: Petition of Wal-Mart Stores East, LP and Sam's East, Inc. for Permission to Aggregate or Combine Demands of Two or More Individual Nonresidential Retail Customers of Electric Energy Pursuant to § 56-577 A 4 of the Code of Virginia.

Oregon Docket No. UM 1953: In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff.

Virginia Case No. PUR-2017-00179: Application of Appalachian Power Company for Approval of an 100% Renewable Energy Rider Pursuant to § 56-577.A.5 of the Code of Virginia.

Missouri Docket No. ER-2018-0145: In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service.

Missouri Docket No. ER-2018-0146: In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service.

Kansas Docket No. 18-WSEE-328-RTS: In the Matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Oregon Docket No. UE 335: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

North Dakota Case No. PU-17-398: In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota.

Virginia Case No. PUR-2017-00179: Application of Appalachian Power Company for Approval of an 100 Percent Renewable Energy Rider Pursuant to § 56-577 A 5 of the Code of Virginia.

Missouri Case No. ET-2018-0063: In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff.

New Mexico Case No. 17-00255-UT: In the Matter of Southwestern Public Service Company's Application for Revision of its Retail Rates Under Advice Notice No. 272.

Virginia Case No. PUR-2017-00157: Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs for Residential and Non-Residential Customers.

Kansas Docket No. 18-KCPE-095-MER: In the Matter of the Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar Energy, Inc. and Great Plains Energy Incorporated.

North Carolina Docket No. E-7, Sub 1146: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Louisiana Docket No. U-34619: In Re: Application for Expedited Certification and Approval of the Acquisition of Certain Renewable Resources and the Construction of a Generation Tie Pursuant to the 1983 and/or/1994 General Orders.

Missouri Case No. EM-2018-0012: In the Matter of the Application of Great Plains Energy Incorporated for Approval of its Merger with Westar Energy, Inc.

2017
Arkansas Docket No. 17-038-U: In the Matter of the Application of Southwestern Electric Power Company for Approval to Acquire a Wind Generating Facility and to Construct a Dedicated Generation Tie Line.

Texas Docket No. 47461: Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Wind Catcher Energy Connection Project.

Oklahoma Cause No. PUD 201700267: Application of Public Service Company of Oklahoma for Approval of the Cost Recovery of the Wind Catcher Energy Connection Project; A Determination There is Need for the Project; Approval for Future Inclusion in Base Rates Cost Recovery of Prudent Costs Incurred by PSO for the Project; Approval of a Temporary Cost Recovery Rider; Approval of Certain Accounting Procedures Regarding Federal Production Tax Credits; Waiver of OAC 165:35-38-5(E); And Such Other Relief the Commission Deems PSO is Entitled.

Nevada Docket No. 17-06003: In the Matter of the Application of Nevada Power Company, d/b/a NV Energy, Filed Pursuant to NRS 704.110(3) and (4), Addressing Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers.

North Carolina Docket No. E-2, Sub 1142: In the Matter of the Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Oklahoma Cause No. PUD 201700151: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Kentucky Case No. 2017-00179: Electronic Application of Kentucky Power Company for (1) a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2017 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; (4) an Order

Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) an Order Granting All Other Requested Relief.

New York Case No. 17-E-0238: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Niagara Mohawk Power Corporation for Electric and Gas Service.

Virginia Case No. PUR-2017-00060: Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs Pursuant to §§ 56-577 A 5 and 56-234 of the Code of Virginia.

New Jersey Docket No. ER17030308: In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, for Approval of a Grid Resiliency Initiative and Cost Recovery Related Thereto, and for Other Appropriate Relief.

Texas Docket No. 46831: Application of El Paso Electric Company to Change Rates.

Oregon Docket No. UE 319: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

New Mexico Case No. 16-00276-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice No. 533.

Minnesota Docket No. E015/GR-16-664: In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota.

Ohio Case No. 16-1852-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, In the Form of an Electric Security Plan.

Texas Docket No. 46449: Application of Southwestern Electric Power Company for Authority to Change Rates.

Arkansas Docket No. 16-052-U: In the Matter of the Application of Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges, and Tariffs.

Missouri Case No. EA-2016-0358: In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood-Montgomery 345 kV Transmission Line.

Florida Docket No. 160186-Ei: In Re: Petition for Increase in Rates by Gulf Power Company.

2016

Missouri Case No. ER-2016-0179: In the Matter of Union Electric Company d/b/a Ameren Missouri Tariffs to Increase its Revenues for Electric Service.

Kansas Docket No. 16-KCPE-593-ACQ: In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar Energy, Inc. by Great Plains Energy Incorporated.

Missouri Case No. EA-2016-0208: In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Offer a Pilot Distributed Solar Program and File Associated Tariff.

Utah Docket No. 16-035-T09: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 34, Renewable Energy Tariff.

Pennsylvania Public Utility Commission Docket No. R-2016-2537359: Pennsylvania Public Utility Commission v. West Penn Power Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537352: Pennsylvania Public Utility Commission v. Pennsylvania Electric Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537355: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537349: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Michigan Case No. U-17990: In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Florida Docket No. 160021-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

Minnesota Docket No. E-002/GR-15-816: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota.

Colorado Public Utilities Commission Docket No. 16AL-0048E: Re: In the Matter of Advice Letter No. 1712-Electric Filed by Public Service Company of Colorado to Replace Colorado PUC No.7-Electric Tariff with Colorado PUC No. 8-Electric Tariff.

Colorado Public Utilities Commission Docket No. 16A-0055E: Re: In the Matter of the Application of Public Service Company of Colorado for Approval of its Solar*Connect Program.

Missouri Public Service Commission Case No. ER-2016-0023: In the Matter of the Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company.

Georgia Public Service Commission Docket No. 40161: In Re: Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT.

Oklahoma Corporation Commission Cause No. PUD 201500273: In the Matter of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

New Mexico Case No. 15-00261-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 513.

2015

Indiana Utility Regulatory Commission Cause No. 44688: Petition of Northern Indiana Public Service Company for Authority to Modify its Rates and Charges for Electric Utility Service and for Approval of: (1) Changes to its Electric Service Tariff Including a New Schedule of Rates and

Charges and Changes to the General Rules and Regulations and Certain Riders; (2) Revised Depreciation Accrual Rates; (3) Inclusion in its Basic Rates and Charges of the Costs Associated with Certain Previously Approved Qualified Pollution Control Property, Clean Coal Technology, Clean Energy Projects and Federally Mandated Compliance Projects; and (4) Accounting Relief to Allow NIPSCO to Defer, as a Regulatory Asset or Liability, Certain Costs for Recovery in a Future Proceeding.

Public Utility Commission of Texas Docket No. 44941: Application of El Paso Electric Company to Change Rates.

Arizona Corporation Commission Docket No. E-04204A-15-0142: In the matter of the Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realized a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to its Operations Throughout the State of Arizona, and for Related Approvals.

Rhode Island Public Utilities Commission Docket No. 4568: In Re: National Grid's Rate Design Plan.

Oklahoma Corporation Commission Cause No. PUD 201500208: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Public Service Commission of Wisconsin Docket No. 4220-UR-121: Application of Northern States Power Company, A Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Public Service Commission Docket No. 15-015-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

New York Public Service Commission Case No. 15-E-0283: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Public Service Commission Case No. 15-G-0284: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Gas Service.

New York Public Service Commission Case No. 15-E-0285: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

New York Public Service Commission Case No. 15-G-0286: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Gas Service.

Public Utilities Commission of Ohio Case No. 14-1693-EL-RDR: In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter Into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.

Public Service Commission of Wisconsin Docket No. 6690-UR-124: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Public Service Commission Docket No. 15-034-U: In the Matter of an Interim Rate Schedule of Oklahoma Gas and Electric Company Imposing a Surcharge to Recover All Investments and Expenses Incurred Through Compliance with Legislative or Administrative Rules, Regulations, or Requirements Relating to the Public Health, Safety or the Environment Under the Federal Clean Air Act for Certain of its Existing Generation Facilities.

Kansas Corporation Commission Docket No. 15-WSEE-115-RTS: In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in their Charges for Electric Service.

Michigan Public Service Commission Case No. U-17767: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

Public Utility Commission of Texas Docket No. 43695: Application of Southwestern Public Service Company for Authority to Change Rates.

Kansas Corporation Commission Docket No. 15-KCPE-116-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Michigan Case No. U-17735: In the Matter of the Application of the Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Kentucky Public Service Commission Case No. 2014-00396: Application of Kentucky Power Company for a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2014 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; and (4) an Order Granting All Other Required Approvals and Relief.

Kentucky Public Service Commission Case No. 2014-00371: In the Matter of the Application of Kentucky Utilities Company for an Adjustment of its Electric Rates.

Kentucky Public Service Commission Case No. 2014-00372: In the Matter of the Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates.

2014

Ohio Public Utilities Commission Case No. 14-1297-EL-SSO: In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

West Virginia Case No. 14-1152-E-42T: Appalachian Power Company and Wheeling Power Company, Both d/b/a American Electric Power, Joint Application for Rate Increases and Changes in Tariff Provisions.

Oklahoma Corporation Commission Cause No. PUD 201400229: In the Matter of the Application of Oklahoma Gas and Electric Company for Commission Authorization of a Plan to Comply with the Federal Clean Air Act and Cost Recovery; and for Approval of the Mustang Modernization Plan.

Missouri Public Service Commission Case No. ER-2014-0258: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase its Revenues for Electric Service.

Pennsylvania Public Utility Commission Docket No. R-2014-2428742: Pennsylvania Public Utility Commission v. West Penn Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428743: Pennsylvania Public Utility Commission v. Pennsylvania Electric Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428744: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428745: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Washington Utilities and Transportation Commission Docket No. UE-141368: In the Matter of the Petition of Puget Sound Energy to Update Methodologies Used to Allocate Electric Cost of Service and For Electric Rate Design Purposes.

Washington Utilities and Transportation Commission Docket No. UE-140762: 2014 Pacific Power & Light Company General Rate Case.

West Virginia Public Service Commission Case No. 14-0702-E-42T: Monongahela Power Company and the Potomac Edison Company Rule 42T Tariff Filing to Increase Rates and Charges.

Ohio Public Utilities Commission Case No. 14-841-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of Case No. 14-841-EL-SSO an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 14AL-0660E: Re: In the Matter of the Advice Letter No. 1672-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Rate Changes Effective July 18, 2014.

Maryland Case No. 9355: In the Matter of the Application of Baltimore Gas and Electric Company for Authority to Increase Existing Rates and Charges for Electric and Gas Service.

Mississippi Public Service Commission Docket No. 2014-UN-132: In Re: Notice of Intent of Entergy Mississippi, Inc. to Modernize Rates to Support Economic Development, Power Procurement, and Continued Investment.

Nevada Public Utilities Commission Docket No. 14-05004: Application of Nevada Power Company d/b/a NV Energy for Authority to Increase its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto.

Utah Public Service Commission Docket No. 14-035-T02: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 32, Service From Renewable Energy Facilities.

Florida Public Service Commission Docket No. 140002-EG: In Re: Energy Conservation Cost Recovery Clause.

Public Service Commission of Wisconsin Docket No. 6690-UR-123: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Connecticut Docket No. 14-05-06: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Virginia Corporation Commission Case No. PUE-2014-00026: Application of Appalachian Power Company for a 2014 Biennial Review for the Provision of Generation, Distribution and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Virginia Corporation Commission Case No. PUE-2014-00033: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to Va. Code § 56-249.6.

Arizona Corporation Commission Docket No. E-01345A-11-0224 (Four Corners Phase): In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Minnesota Public Utilities Commission Docket No. E-002/GR-13-868: In the Matter of the Application of Northern States Power Company, for Authority to Increase Rates for Electric Service in Minnesota.

Utah Public Service Commission Docket No. 13-035-184: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Missouri Public Service Commission Case No. EC-2014-0224: In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service.

Oklahoma Corporation Commission Cause No. PUD 201300217: Application of Public Service Company of Oklahoma to be in Compliance with Order No. 591185 Issued in Cause No. PUD 201100106 Which Requires a Base Rate Case to be Filed by PSO and the Resulting Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Public Utilities Commission of Ohio Case No. 13-2386-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.

2013
Oklahoma Corporation Commission Cause No. PUD 201300201: Application of Public Service Company of Oklahoma for Commission Authorization of a Standby and Supplemental Service Rate Schedule.

Georgia Public Service Commission Docket No. 36989: Georgia Power's 2013 Rate Case.

Florida Public Service Commission Docket No. 130140-EI: Petition for Rate Increase by Gulf Power Company.

Public Utility Commission of Oregon Docket No. UE 267: In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment, Five-Year Cost of Service Opt-Out.

Illinois Commerce Commission Docket No. 13-0387: Commonwealth Edison Company Tariff Filing to Present the Illinois Commerce Commission with an Opportunity to Consider Revenue Neutral Tariff Changes Related to Rate Design Authorized by Subsection 16-108.5 of the Public Utilities Act.

Iowa Utilities Board Docket No. RPU-2013-0004: In Re: MidAmerican Energy Company.

South Dakota Public Utilities Commission Docket No. EL12-061: In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates. (filed with confidential stipulation)

Kansas Corporation Commission Docket No. 13-WSEE-629-RTS: In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Public Utility Commission of Oregon Docket No. UE 263: In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Arkansas Public Service Commission Docket No. 13-028-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

Virginia State Corporation Commission Docket No. PUE-2013-00020: Application of Virginia Electric and Power Company for a 2013 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Florida Public Service Commission Docket No. 130040-EI: Petition for Rate Increase by Tampa Electric Company.

South Carolina Public Service Commission Docket No. 2013-59-E: Application of Duke Energy Carolinas, LLC, for Authority to Adjust and Increase Its Electric Rates and Charges.

Public Utility Commission of Oregon Docket No. UE 262: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

New Jersey Board of Public Utilities Docket No. ER12111052: In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program (“2012 Base Rate Filing”)

North Carolina Utilities Commission Docket No. E-7, Sub 1026: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Public Utility Commission of Oregon Docket No. UE 264: PACIFICORP, dba PACIFIC POWER, 2014 Transition Adjustment Mechanism.

Public Utilities Commission of California Docket No. 12-12-002: Application of Pacific Gas and Electric Company for 2013 Rate Design Window Proceeding.

Public Utilities Commission of Ohio Docket Nos. 12-426-EL-SSO, 12-427-EL-ATA, 12-428-EL-AAM, 12-429-EL-WVR, and 12-672-EL-RDR: In the Matter of the Application of the Dayton Power and Light Company Approval of its Market Offer.

Minnesota Public Utilities Commission Docket No. E-002/GR-12-961: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota.

North Carolina Utilities Commission Docket E-2, Sub 1023: In the Matter of Application of Progress Energy Carolinas, Inc. For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

2012
Public Utility Commission of Texas Docket No. 40443: Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2012-218-E: Application of South Carolina Electric & Gas Company for Increases and Adjustments in Electric Rate Schedules and Tariffs and Request for Mid-Period Reduction in Base Rates for Fuel.

Kansas Corporation Commission Docket No. 12-KCPE-764-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Kansas Corporation Commission Docket No. 12-GIMX-337-GIV: In the Matter of a General Investigation of Energy-Efficiency Policies for Utility Sponsored Energy Efficiency Programs.

Florida Public Service Commission Docket No. 120015-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

California Public Utilities Commission Docket No. A.11-10-002: Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design.

Utah Public Service Commission Docket No. 11-035-200: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

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Public Utility Commission of Texas Docket No. 39896: Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs.

Missouri Public Service Commission Case No. EO-2012-0009:In the Matter of KCP&L Greater Missouri Operations Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism.

Colorado Public Utilities Commission Docket No. 11AL-947E: In the Matter of Advice Letter No. 1597-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective December 23, 2011.

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California Public Utilities Commission Docket No. A.11-06-007: Southern California Edison's General Rate Case, Phase 2.

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Arizona Corporation Commission Docket No. E-01345A-11-0224: In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Oklahoma Corporation Commission Cause No. PUD 201100087: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

South Carolina Public Service Commission Docket No. 2011-271-E: Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates and Charges.

Pennsylvania Public Utility Commission Docket No. P-2011-2256365: Petition of PPL Electric Utilities Corporation for Approval to Implement Reconciliation Rider for Default Supply Service.

North Carolina Utilities Commission Docket No. E-7, Sub 989: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Florida Public Service Commission Docket No. 110138: In Re: Petition for Increase in Rates by Gulf Power Company.

Public Utilities Commission of Nevada Docket No. 11-06006: In the Matter of the Application of Nevada Power Company, filed pursuant to NRS 704.110(3) for authority to increase its annual revenue requirement for general rates charged to all classes of customers to recover the costs of constructing the Harry Allen Combined Cycle plant and other generating, transmission, and distribution plant additions, to reflect changes in the cost of capital, depreciation rates and cost of service, and for relief properly related thereto.

North Carolina Utilities Commission Docket Nos. E-2, Sub 998 and E-7, Sub 986: In the Matter of the Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct.

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Utah Public Service Commission Docket No. 10-035-124: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Maryland Public Utilities Commission Case No. 9249: In the Matter of the Application of Delmarva Power & Light for an Increase in its Retail Rates for the Distribution of Electric Energy.

Minnesota Public Utilities Commission Docket No. E002/GR-10-971: In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota.

Michigan Public Service Commission Case No. U-16472: In the Matter of the Detroit Edison Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

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Colorado Public Utilities Commission Docket No. 10A-554EG: In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to its DSM Plan, Including Long-Term Electric Energy Savings Goals, and Incentives.

Public Service Commission of West Virginia Case No. 10-0699-E-42T: Appalachian Power Company and Wheeling Power Company Rule 42T Application to Increase Electric Rates.

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Georgia Public Service Commission Docket No. 31958-U: In Re: Georgia Power Company's 2010 Rate Case.

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Colorado Public Utilities Commission Docket No. 10M-254E: In the Matter of Commission Consideration of Black Hills Energy's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Colorado Public Utilities Commission Docket No. 10M-245E: In the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

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Public Utility Commission of Oregon Docket No. UE 217: In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision.

Mississippi Public Service Commission Docket No. 2010-AD-57: In Re: Proposal of the Mississippi Public Service Commission to Possibly Amend Certain Rules of Practice and Procedure.

Indiana Utility Regulatory Commission Cause No. 43374: Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code § 8-1-2.5-1, *ET SEQ.*, for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code §§ 8-1-2.5-1 *ET SEQ.* and 8-1-2-42 (a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the Powershare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests.

Public Utility Commission of Texas Docket No. 37744: Application of Entergy Texas, Inc. for Authority to Change Rates and to Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2009-489-E: Application of South Carolina Electric & Gas Company for Adjustments and Increases in Electric Rate Schedules and Tariffs.

Kentucky Public Service Commission Case No. 2009-00459: In the Matter of General Adjustments in Electric Rates of Kentucky Power Company.

Virginia State Corporation Commission Case No. PUE-2009-00125: For acquisition of natural gas facilities Pursuant to § 56-265.4:5 B of the Virginia Code.

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Public Service Commission of Delaware Docket No. 09-414: In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Charges.

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Public Service Commission of Utah Docket No. 09-035-15 *Phase I*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Service Commission of Utah Docket No. 09-035-23: In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.

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Arkansas Public Service Commission Docket No. 09-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Oklahoma Corporation Commission Docket No. PUD 200800398: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

Public Utilities Commission of Nevada Docket No. 08-12002: In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed pursuant to NRS §704.110(3) and NRS §704.110(4) for authority to increase its annual revenue requirement for general rates charged to all classes of customers, begin to recover the costs of acquiring the Bighorn Power Plant, constructing the Clark Peakers, Environmental Retrofits and other generating, transmission and distribution plant additions, to reflect changes in cost of service and for relief properly related thereto.

New Mexico Public Regulation Commission Case No. 08-00024-UT: In the Matter of a Rulemaking to Revise NMPRC Rule 17.7.2 NMAC to Implement the Efficient Use of Energy Act.

Indiana Utility Regulatory Commission Cause No. 43580: Investigation by the Indiana Utility Regulatory Commission, of Smart Grid Investments and Smart Grid Information Issues Contained in 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. § 2621(d)), as Amended by the Energy Independence and Security Act of 2007.

Louisiana Public Service Commission Docket No. U-30192 *Phase II (February 2009)*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

South Carolina Public Service Commission Docket No. 2008-251-E: In the Matter of Progress Energy Carolinas, Inc.'s Application For the Establishment of Procedures to Encourage Investment in Energy Efficient Technologies; Energy Conservation Programs; And Incentives and Cost Recovery for Such Programs.

2008
Colorado Public Utilities Commission Docket No. 08A-366EG: In the Matter of the Application of Public Service Company of Colorado for approval of its electric and natural gas demand-side management (DSM) plan for calendar years 2009 and 2010 and to change its electric and gas DSM cost adjustment rates effective January 1, 2009, and for related waivers and authorizations.

Public Service Commission of Utah Docket No. 07-035-93: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge.

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Public Utilities Commission of Nevada Docket No. 07-12001: In the Matter of the Application of Sierra Pacific Power Company for authority to increase its general rates charged to all classes of electric customers to reflect an increase in annual revenue requirement and for relief properly related thereto.

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Louisiana Public Service Commission Docket No. U-30192: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Public Utility Commission of Oregon Docket No. UG 173: In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Request to Open an Investigation into the Earnings of Cascade Natural Gas.

2006
Public Utility Commission of Oregon Docket No. UE 180/UE 181/UE 184: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.

Public Utility Commission of Oregon Docket No. UE 179: In the Matter of PACIFICORP, dba PACIFIC POWER AND LIGHT COMPANY Request for a general rate increase in the company's Oregon annual revenues.

Public Utility Commission of Oregon Docket No. UM 1129 *Phase II*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

2005
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I Compliance*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

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2020
Regarding Missouri Senate Joint Resolution 34: Written testimony submitted to the Missouri Senate Transportation, Infrastructure and Public Safety Committee, January 30, 2020.

2019
Regarding North Carolina Senate Bill 559: Written testimony submitted to the North Carolina Committee on Agriculture/Environment/Natural Resources, April 17, 2019.

Regarding Missouri Senate Joint Resolution 25: Written testimony submitted to the Missouri Senate Committee on Judiciary, March 28, 2019.

Regarding South Carolina House Bill 3659: Written testimony submitted to the South Carolina Senate Committee on Judiciary, March 14, 2019.

Regarding Kansas Senate Bill 69: Written testimony submitted to the Kansas Committee on Utilities, February 19, 2019.

2018
Regarding Missouri Senate Bill 564: Testimony before the Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment, January 10, 2018.

2017
Regarding Missouri Senate Bill 190: Testimony before the Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment, January 25, 2017.

2016
Regarding Missouri House Bill 1726: Testimony before the Missouri House Energy and Environment Committee, April 26, 2016.

2014
Regarding Kansas House Bill 2460: Testimony Before the Kansas House Standing Committee on Utilities and Telecommunications, February 12, 2014.

2012
Regarding Missouri House Bill 1488: Testimony Before the Missouri House Committee on Utilities, February 7, 2012.

2011
Regarding Missouri Senate Bills 50, 321, 359, and 406: Testimony Before the Missouri Senate Veterans' Affairs, Emerging Issues, Pensions, and Urban Affairs Committee, March 9, 2011.

AFFIDAVITS
2015
Supreme Court of Illinois, Docket No. 118129, Commonwealth Edison Company et al., respondents, v. Illinois Commerce Commission et al. (Illinois Competitive Energy Association et al., petitioners). Leave to appeal, Appellate Court, First District.

2011
Colorado Public Utilities Commission Docket No. 11M-951E: In the Matter of the Petition of Public Service Company of Colorado Pursuant to C.R.S. § 40-6-111(1)(d) for Interim Rate Relief Effective on or before January 21, 2012.

ENERGY INDUSTRY PUBLICATIONS AND PRESENTATIONS
Panelist, Renewable Energy Options for Large Utility Customers, NARUC Center for Partnership & Innovation Webinar Series, January 16, 2020.

Panelist, Pathways to Integrating Customer Clean Energy Demand in Utility Planning, REBA: Market Innovation webinar, January 13, 2020.

Panelist, Should Full Electrification of Energy Systems be Our Goal? If it's No Longer Business as Usual, What Does That Mean for Consumers?, National Association of State Utility Consumer Advocates 2019 Annual Meeting, San Antonio, Texas, November 18, 2019.

Panelist, Fleet Electrification, Federal Utility Partnership Working Group Seminar, Washington, DC, November 8, 2019.

Panelist, Tackling the Challenges of Extreme Weather, Edison Electric Institute Fall National Key Accounts Workshop, Las Vegas, Nevada, October 8, 2019.

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Panelist, From the Consumer Perspective, Mid-American Regulatory Conference 2019 Annual Meeting, Des Moines, Iowa, August 13, 2019.

Panelist, Redefining Resiliency: Emerging Technologies Benefiting Customers and the Grid, EPRI 2019 Summer Seminar, Chicago, Illinois, August 12, 2019.

Panelist, Energy Policies for Economic Growth, 2019 Energy Policy Summit, NCSL Legislative Summit, Nashville, Tennessee, August 5, 2019.

Panelist, Gateway to Energy Empowerment for Customers, Illumination Energy Summit, Columbus, Ohio, May 15, 2019.

Panelist, Advancing Clean Energy Solutions Through Stakeholder Collaborations, 2019 State Energy Conference of North Carolina, Raleigh, North Carolina, May 1, 2019.

Panelist, Fleet Electrification: Getting Ready for the Transition, Edison Electric Institute Spring National Key Accounts Workshop, Seattle, Washington, April 8, 2019.

Panelist, Where the Fleet Meets the Pavement, Which Way to Electrification of the U.S. Transportation System?, Washington, D.C., April 4, 2019.

Panelist, Improving Renewable Energy Offerings: What Have We Learned?, Advanced Energy Economy Webinar, March 26, 2019.

Speaker, National Governors Association Southeast Regional Transportation Electrification Workshop, Nashville, Tennessee, March 11, 2019.

Speaker, Walmart Spotlight: A Day in the Life of a National Energy Manager, Touchstone Energy Cooperatives Net Conference 2019, San Diego, California, February 12, 2019.

Panelist, National Accounts: The Struggle is Real, American Public Power Association Customer Connections Conference, Orlando, Florida, November 6, 2018.

Panelist, Getting in Front of Customers Getting Behind the Meter Solutions, American Public Power Association Customer Connections Conference, Orlando, Florida, November 6, 2018.

Panelist, Sustainable Fleets: The Road Ahead for Electrifying Fleet Operations, EEI National Key Accounts 2018 Fall Workshop, San Antonio, Texas, October 23, 2018.

Panelist, Meeting Corporate Clean Energy Requirements in Virginia, Renewable Energy Buyers Alliance Summit, Oakland, California, October 15, 2018.

Panelist, What Are the Anticipated Impacts on Pricing and Reliability in the Changing Markets?, Southwest Energy Conference, Phoenix, Arizona, September 21, 2018.

Speaker, Walmart's Project Gigaton – Driving Renewable Energy Sourcing in the Supply Chain, Smart Energy Decisions Webcast Series, July 11, 2018.

Panelist, Customizing Energy Solutions, Edison Electric Institute Annual Convention, San Diego, California, June 7, 2018.

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Panelist, The Past, Present, and Future of Renewable Energy: What Role Will PURPA, Mandates, and Collaboration Play as Renewables Become a Larger Part of Our Energy Mix?, 36th National Regulatory Conference, Williamsburg, Virginia, May 17, 2018.

Panelist, Sustainability Milestone Deep Dive Session, Walmart Global Sustainability Leaders Summit, Bentonville, Arkansas, April 18, 2018.

Panelist, The Customer's Voice, Tennessee Valley Authority Distribution Marketplace Forum, Murfreesboro, Tennessee, April 3, 2018.

Panelist, Getting to Yes with Large Customers to Meet Sustainability Goals, The Edison Foundation Institute for Electric Innovation Powering the People, March 7, 2018.

Panelist, The Corporate Quest for Renewables, 2018 NARUC Winter Policy Summit, Washington, D.C., February 13, 2018.

Panelist, Solar and Renewables, Touchstone Energy Cooperatives NET Conference 2018, St. Petersburg, Florida, February 6, 2018.

Panelist, Missouri Public Service Commission November 20, 2017 Workshop in File No. EW-2017-0245.

Panelist, Energy and Climate Change, 2017-18 Arkansas Law Review Symposium: Environmental Sustainability and Private Governance, Fayetteville, Arkansas, October 27, 2017.

Panelist, Customer – Electric Company – Regulator Panel, Edison Electric Institute Fall National Key Accounts Workshop, National Harbor, Maryland, October 12, 2017.

Panelist, What Do C&I Buyers Want, Solar Power International, Las Vegas, Nevada, September 12, 2017.

Panelist, Partnerships for a Sustainable Future, American Public Power Association National Conference, Orlando, Florida, June 20, 2017.

Panelist, Corporate Renewable Energy Buyers in the Southeast, SEARUC 2017, Greensboro, Georgia, June 12, 2017.

Panelist, Transitioning Away from Traditional Utilities, Utah Association of Energy Users Annual Conference, Salt Lake City, Utah, May 18, 2017.

Panelist, Regulatory Approaches for Integrating and Facilitating DERs, New Mexico State University Center for Public Utilities Advisory Council Current Issues 2017, Santa Fe, New Mexico, April 25, 2017.

Presenter, Advancing Renewables in the Midwest, Columbia, Missouri, April 24, 2017.

Panelist, Leveraging New Energy Technologies to Improve Service and Reliability, Edison Electric Institute Spring National Key Accounts Workshop, Phoenix, Arizona, April 11, 2017.

Panelist, Private Sector Demand for Renewable Power, Vanderbilt Law School, Nashville, Tennessee, April 4, 2017.

Panelist, Expanding Solar Market Opportunities, 2017 Solar Power Colorado, Denver, Colorado, March 15, 2017.

Panelist, Renewables: Are Business Models Keeping Up?, Touchstone Energy Cooperatives NET Conference 2017, San Diego, California, January 30, 2017.

Panelist, The Business Case for Clean Energy, Minnesota Conservative Energy Forum, St. Paul, Minnesota, October 26, 2016.

Panelist, M-RETS Stakeholder Summit, Minneapolis, Minnesota, October 5, 2016.

Panelist, 40th Governor's Conference on Energy & the Environment, Kentucky Energy and Environment Cabinet, Lexington, Kentucky, September 21, 2016.

Panelist, Trends in Customer Expectations, Wisconsin Public Utility Institute, Madison, Wisconsin, September 6, 2016.

Panelist, The Governor's Utah Energy Development Summit 2015, May 21, 2015.

Mock Trial Expert Witness, The Energy Bar Association State Commission Practice and Regulation Committee and Young Lawyers Committee and Environment, Energy and Natural Resources Section of the D.C. Bar, Mastering Your First (or Next) State Public Utility Commission Hearing, February 13, 2014.

Panelist, Customer Panel, Virginia State Bar 29th National Regulatory Conference, Williamsburg, Virginia, May 19, 2011.

Chriss, S. (2006). "Regulatory Incentives and Natural Gas Purchasing – Lessons from the Oregon Natural Gas Procurement Study." Presented at the 19th Annual Western Conference, Center for Research in Regulated Industries Advanced Workshop in Regulation and Competition, Monterey, California, June 29, 2006.

Chriss, S. (2005). "Public Utility Commission of Oregon Natural Gas Procurement Study." Public Utility Commission of Oregon, Salem, OR. Report published in June, 2005. Presented to the Public Utility Commission of Oregon at a special public meeting on August 1, 2005.

Chriss, S. and M. Radler (2003). "Report from Houston: Conference on Energy Deregulation and Restructuring." USAEE Dialogue, Vol. 11, No. 1, March, 2003.

Chriss, S., M. Dwyer, and B. Pulliam (2002). "Impacts of Lifting the Ban on ANS Exports on West Coast Crude Oil Prices: A Reconsideration of the Evidence." Presented at the 22nd USAEE/IAEE North American Conference, Vancouver, BC, Canada, October 6-8, 2002.
Contributed to chapter on power marketing: "Power System Operations and Electricity Markets," Fred I. Denny and David E. Dismukes, authors. Published by CRC Press, June 2002.

Contributed to "Moving to the Front Lines: The Economic Impact of the Independent Power Plant Development in Louisiana," David E. Dismukes, author. Published by the Louisiana State University Center for Energy Studies, October 2001.

Dismukes, D.E., D.V. Mesyanzhinov, E.A. Downer, S. Chriss, and J.M. Burke (2001). "Alaska Natural Gas In-State Demand Study." Anchorage: Alaska Department of Natural Resources.

MR. TRATHEN: Madam Chair, Marcus Trathen for Tech Customers.

CHAIR MITCHELL: All right, Mr. Trathen.

MR. TRATHEN: I have an identical motion for Mr. Kurt Strunk, if now is the appropriate time.

CHAIR MITCHELL: Please proceed.

MR. TRATHEN: He has filed testimony consisting of 62 pages and 22 exhibits in this proceeding, and he has, by prior Order, been excused from testimony in this separate proceeding. I'd ask that his testimony be copied into the record.

CHAIR MITCHELL: All right. Hearing no objections, Mr. Trathen, your motion is allowed.

MR. TRATHEN: Thank you.

(Whereupon, the prefiled testimony of Kurt G. Strunk was copied into the record as if given orally from the stand. The confidential version was filed under seal.)

(Whereupon, Exhibits KGS-1 through KGS-22 were admitted into evidence. Confidential Exhibits KGS-17, KGS-18, KGS-19, and KGS-21 were filed under seal.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1214

In the Matter of	
Application of Duke Energy Carolinas,	)
LLC, for Adjustment of Rates and Charges	)
Applicable to Electric Utility Service in	)
North Carolina	)

TESTIMONY OF KURT G. STRUNK

ON BEHALF OF
APPLE INC., FACEBOOK, INC. AND GOOGLE LLC
(THE "TECH CUSTOMERS")

February 18, 2020

CONTENTS

I. QUALIFICATIONS

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

A. My name is Kurt G. Strunk. I am a Director of National Economic Research Associates ("NERA"). My business address is 1166 Avenue of the Americas, New York, NY 10036.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I have twenty-five years of experience consulting to governments, regulators, and utilities on energy-related matters. My practice at NERA focuses on the strategic, regulatory, and financial issues facing electric and gas utilities as their markets restructure and evolve. My experience includes dozens of assignments relating to the development of the power sector in the South-Atlantic region, as well as several assignments related to North Carolina and the utilities that operate there. As a result, I am very familiar with the regulatory, legislative and market environments in which Duke Energy Carolinas, LLC ("DEC" or "Company") operates.

I routinely address regulatory policy and regulatory reform in my consulting work. My experience includes serving as an advisor to utilities, intervenors, and regulators on major regulatory reform programs and regulatory innovations. I have authored articles on numerous energy regulatory issues and have testified on the application of the prudence standard to utility decision making. In addition, my work requires that I maintain a detailed knowledge of utility financial matters and regulatory policy. I have served as a testifying expert in numerous cases dealing with utility cost of capital and financial structure.

Prior to joining NERA's Energy Practice, I was a member of NERA's Securities and Finance Practice. Exhibit KGS 1 contains a more detailed statement of my qualifications.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION PREVIOUSLY?

A. Yes. In 2017, I submitted testimony on behalf of the North Carolina Sustainable Energy Association in the 2016 Avoided Cost proceeding, Docket No. E-100, Sub 148. In addition, I submitted testimony on behalf of the Tech Customers in DEC's previous rate case, Docket No. E-7, Sub 1146.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY AGENCIES IN OTHER JURISDICTIONS?

A. Yes. I frequently serve as an expert in matters before state and federal regulatory commissions. I have presented expert evidence in matters before the Arkansas Public Service Commission, the Arizona Corporation Commission, the California Public Utilities Commission, the Hawaii Public Utilities Commission, the Maryland Public Service Commission, the Massachusetts Energy Facilities Siting Board, the Nevada Public Utilities Commission, the Ohio Public Utilities Commission, the Regulatory Commission of Alaska, the Washington Utilities and Transportation Commission, as well as the Federal Energy Regulatory Commission and the National Energy Board of Canada.

II. PURPOSE OF TESTIMONY AND CONCLUSIONS

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY.

A. I have been asked to review the DEC rate case filing and to provide my opinions to the Commission on various economic, regulatory, and financial matters raised by this filing. Specifically, I was asked to review:

- DEC's overall application and the drivers of the proposed 9.2 percent base rate increase;
- DEC's proposed deferral of its grid modernization investments and the purported rationale for the use of a deferral mechanism;
- DEC's proposed cost of capital, with a specific focus on the capital structure, cost of equity, and the interrelation between the two;
- The large increases in the net book values of DEC's coal generation assets; and
- DEC's proposal for returning the benefits of the Federal Tax Cuts and Jobs Act ("Tax Act") to customers.

My testimony responds to the testimony of DEC witnesses who address these topics and includes evidence that is intended to assist the Commission in deciding these matters.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I have reached the following primary conclusions.

<u>Drivers of Base Rate Increase</u>

(1) **DEC has applied for a base rate increase of 9.2 percent, primarily driven by additions to plant, changes to depreciation rates, and a purported increase in its cost of equity capital relative to the return on equity ("ROE") allowed in the last rate case (in Docket No. E-7, Sub 1146).** DEC's proposed rate increase comes on the heels of a series of past requests for base rate increases. In the instant docket, DEC has requested a revenue requirement increase of $445 million.[1] As in any regulatory proceeding with

[1] *See* McManeus Direct Testimony, Exhibit 1, page 1 (Sept. 30, 2019). This amount has been updated to $464,585, *see* McManeus Supplemental Direct Testimony, Supplemental Exhibit 1,

significant monies at stake, the magnitude of DEC's spending warrants particular scrutiny.

Grid Improvement Investments

(2) **DEC has not justified the use of a regulatory deferral mechanism for its grid improvement investments.** Deferrals can serve as appropriate regulatory mechanisms for well-defined costs that meet the Commission's two-pronged test, which requires (1) the costs to be unusual or extraordinary in nature and (2) the failure to implement a deferral to have a material and negative effect on the utility's financial condition. While deferrals may be appropriate for costs related to unusual events, DEC has failed to justify treating grid improvement investments any differently from the other infrastructure investments that comprise DEC's rate base.

(3) DEC's Grid Improvement Plan is substantially similar to its Power/Forward Carolinas program proposed in its last rate case, a program for which the Commission elected not to approve deferral accounting. Denial of DEC's request to defer Grid Improvement Plan costs is warranted on the same grounds that the Commission denied deferral of Power/Forward Carolinas costs. As with Power/Forward Carolinas, DEC fails to adequately differentiate between ordinary, ongoing transmission and distribution investments and the Grid Improvement Plan investments it proposes for deferral. Based on the evidence advanced by DEC, the attribution of costs into the grid improvement category is seemingly arbitrary. Furthermore, the justifications used to legitimize the Grid Improvement Plan include speculative, indirect benefits that have not been adequately supported.

(4) **The Company has begun to study Integrated Systems and Operations Planning ("ISOP")**, which will incorporate resources at the distribution level into the Integrated Resource Planning process—a process that has traditionally focused on central-station generation and transmission investments. DEC runs the risk that its current Grid Improvement Plan investments may turn out not to be optimal after the ISOP process is complete. This is because ISOP efforts could conceivably change the nature of the grid improvements needed to optimize DEC's system. In this context, even if deferral were otherwise appropriate, it seems premature for the Commission to authorize the deferral of over $1 billion in

page 2 (Feb. 14, 2020), but it appears that DEC is not seeking this additional revenue in this proceeding. *See* McManeus Supplemental Direct Testimony, page 9.

investment, given the fluid nature of DEC's planning and the fact that the investments may turn out not to be optimal.

Cost of Capital / Rate of Return

(5) **DEC's applied-for cost of capital exceeds the level that is required under the fair return standards established in the Supreme Court *Hope* and *Bluefield* decisions[2] and should therefore be rejected.** I recommend that the Commission reject the ROE requested by the Company in favor of a lower ROE in line with the lower risk profile of the Company, as demonstrated by objective measures.

(6) **DEC has not convincingly demonstrated that the 53 percent equity ratio optimizes its capital structure and results in the lowest cost of capital for customers.** Generally speaking, the higher the equity ratio, the lower the level of financial risk faced by the firm and the lower the required ROE. In other words, a utility with more equity deserves a lower allowed ROE than a utility with less equity, all else equal. The relatively high equity ratio proposed by DEC—near the top of the equity ratios recently allowed in regulatory practice—should correspond to a lower required rate of return than advocated by DEC's witness, Mr. Hevert. His proposed ROE is based on his estimate of the proxy group utilities' cost of capital and adjusted upward based on subjective opinions and unsupported by evidence. When making his recommendation, Mr. Hevert should have considered how the investment community perceives the difference in business risk and financial risk. He did not.

(7) **Mr. Hevert overstates the required return on equity because he does not properly adjust for the differences in risk between DEC and the proxy group.** Mr. Hevert argues, without any evidence, that DEC bears certain risks that require a return near the top of the zone of reasonableness. Yet objective evidence from Standard & Poor's demonstrates that DEC is *less* risky than the proxy group companies used by Mr. Hevert in his analysis. The Commission should, when establishing a fair return for DEC, recognize DEC's lower risk, as indicated by Standard & Poor's.

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[2] *See Federal Power Commission et al. v. Hope Natural Gas Co.,* 320 U.S. 591 (1944), and *Bluefield Water Works & Improvement Co. v. Public Service Comm'n,* 262 U.S. 679 (1923).

Investment in Coal-Fired Generation

(8) **DEC incurred $944 million in capital expenditures for its coal-fired power plants during the 2017 and 2018 calendar years.** Given the sheer magnitude of the investments made, the declining economics of many if not all of DEC's coal units, and certain statements made by DEC, as documented internally, I have serious questions about the prudency of these investments. **I recommend that the Commission scrutinize these investments** and whether the decisions made [redacted] were prudent. Unless DEC makes a strong affirmative case for the prudence of its investments, I recommend the Commission not allow inclusion in rate base of the incremental capital expenditures spent at those units between the prior rate case and this one.

Benefits of Tax Act

(9) **DEC is carrying $783 million in unprotected Excess Deferred Income Taxes ("EDIT") on its books that, DEC asserts, relate to property, plant, and equipment, which it proposes to amortize and return to customers over 20 years.** Based upon a survey of regulatory precedent during the last 12 months, I recommend that the Commission shorten the amortization of these monies to no more than five years. This will provide an offset to DEC's proposed rate increase and will track the prevailing treatment by other regulatory commissions.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In Section III, I explain the primary drivers of DEC's request for a rate increase. In Section IV, I explain why DEC's request for deferral of Grid Improvement Plan costs should be rejected and how DEC's Grid Improvement Plan is simply a rebranding of Power/Forward Carolinas from the 2017 rate case. In Section V, I offer evidence on the relative riskiness of DEC as compared to the proxy group used by Mr. Hevert and rebut his claim that DEC is riskier. Section VI provides a summary of the prudence standard and evidence to suggest that further scrutiny of

DEC's coal-related investments is warranted. Section VII addresses the amortization period for returning unprotected EDIT to customers.

III. DEC's Proposed Rate Increase Stems from Major Additions to Plant, Accelerated Amortization, and a Higher Return on Equity.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. I was asked to examine the DEC rate application and to identify the high-level drivers of the proposed base rate increase. While there are other changes in DEC's costs that represent important components of the proposed change in revenue requirement, I chose to focus on the following three major drivers behind the higher applied-for revenue requirement that I identified:

a. Cost of capital, reflecting an increase in ROE from 9.9 percent to 10.3 percent;

b. Increase in rate base, driven by post-test year capital additions; and

c. Increase in depreciation expense as the result of a new depreciation study.

Table 1 below illustrates how these three key changes affect the Company's proposed revenue.

Table 1: DEC Rate Increase Cost Drivers

	Test Year Revenue Requirement (1)	Test Year Revenue Requirement, 10.30% ROE (2)	Accounting Adjustments (3)	Proposed Increase (4)	Proposed Revenue Requirement (5) (2)+(3)+(4)
RECOUPING OF OPERATING EXPENSES					
Fuel used in electric generation	$ 989,374		$ 168,855	$ -	$ 1,158,229
Purchased power	194,348		(170,936)	-	23,412
Other operation and maintenance expense	1,375,939		(205,547)	1,691	1,172,083
Depreciation and amortization	838,805		358,328	-	1,197,133
General taxes	194,681		12,832	-	207,513
Interest on customer deposits	7,130		-	-	7,130
Net income taxes	224,997		(59,918)	103,355	268,434
Amortization of investment tax credit	(3,526)		690	-	(2,836)
Recouping of operating expenses	$ 3,821,748	$ 3,821,748	$ 104,304	$ 105,046	$ 4,031,098
RETURN ON RATE BASE					
Rate base before increase	$ 14,556,650				$ 14,556,650
Adjust for costs recovered through non-fuel riders	-		(63,371)	-	(63,371)
Adjust for post test year additions to plant in service	-		714,506	-	714,506
Amortize deferred environmental costs	-		294,069	-	294,069
Adjust for approved regulatory assets and liabilities	-		(107,231)	-	(107,231)
Amortize severance costs	-		35,346	-	35,346
Adjust cash working capital	-		(20,794)	-	(20,794)
Adjust depreciation for new rates	-		(72,913)	-	(72,913)
Update deferred balance and amortize storm costs	-		129,731	-	129,731
Other, net	-		(1,250)	-	(1,250)
Expenses from proposed increase	-		-	47,878	47,878
Total rate base	14,556,650	14,556,650	908,093	47,878	15,512,621
Return on rate base (%)	7.44%	7.58%	7.58%	7.58%	7.58%
Return on rate base	$ 1,082,336	$ 1,103,205	$ 68,822	$ 3,629	$ 1,175,655
Revenue requirement	**$ 4,904,084**	$ 4,924,953	$ 173,126	$ 108,675	**$ 5,206,753**

**All figures correspond to McManeus Direct, Exhibit 1, Pages 1-2* (Sept. 30, 2019). *No adjustments have been made (differences due to rounding). All figures in thousands of dollars.*

IV. DEC'S PROPOSED USE OF A REGULATORY DEFERRAL FOR THE GRID IMPROVEMENT PLAN SHOULD NOT BE APPROVED, AS THAT PLAN DOES NOT REFLECT UNUSUAL OR EXTRAORDINARY INVESTMENTS.

Q. PLEASE DESCRIBE THE REGULATORY MECHANISM SOUGHT BY DEC TO DEFER THE COSTS OF ITS INVESTMENTS IN WHAT IT CONSIDERS TO BE GRID IMPROVEMENTS.

A. In its Application, DEC seeks approval for a regulatory deferral of "certain costs related to investments in the transmission and distribution grid under the

Company's Grid Improvement Plan,"[3] a three-year plan spanning calendar years 2020 through 2022. Specifically, DEC is seeking deferral of depreciation of capital investments, return on capital investments (net of accumulated depreciation) at the Company's weighted average cost of capital, O&M expense, and a return on the balance of costs deferred at the Company's weighted average cost of capital.[4]

Q. IS THIS SIMILAR TO THE REQUEST MADE BY DEC IN ITS LAST RATE CASE?

Yes. DEC made a similar request in Docket No. E-7, Sub 1146, for recovery of grid modernization expenses through a Grid Reliability Rider ("GRR") or a regulatory deferral. The GRR and/or deferral request was purportedly necessary to provide funds for DEC's then-proposed $14 billion "Power/Forward Carolinas" initiative and "to accelerate the T&D investments being made to better serve customers, replace aging infrastructure, ensure the grid remains resilient and secure, respond to the growth in homes, businesses, and industry, and support the current and projected wave of renewable projects."[5] Importantly, DEC in that rate case requested deferral treatment in the event that the Commission did not approve the GRR. I testified on behalf of the Tech Customers that DEC's proposed investments through its Power Forward Carolinas program did not differ significantly from customary spend investments, and thus I opposed DEC's recovery through the proposed GRR and through any sort of deferral.

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[3] McManeus Direct Testimony, page 4, lines 12-13.

[4] McManeus Direct Testimony, page 38, lines 6-12.

[5] DEC Application, Docket No. E-7, Sub 1146, pages 5-6.

In its final order in that rate case docket, the Commission held that grid improvement costs do not merit special treatment. The Commission rejected both the rider *and* the proposal for deferral accounting, stating the following in Findings of Fact Nos. 42 and 43:

> 42. DEC has failed to show that exceptional circumstances exist to justify the establishment of the Grid Rider for recovery of its Power Forward Carolinas (Power Forward) costs.
>
> 43. DEC has failed to show at this time that Power Forward costs qualify for deferral accounting treatment.[6]

Q. WHAT DID THE COMMISSION OBSERVE IN THAT ORDER REGARDING THE DEFERRAL REQUEST?

A. The Commission made a number of relevant findings. The Commission emphasized that it has in the past "historically treated deferral accounting as a tool to be allowed only as an exception to the general rule, and its use has been allowed sparingly."[7] Consistent with this view, the Commission rejected the request finding that "reasons DEC says underlie the need for Power Forward are not unique or extraordinary to DEC, nor are they unique or extraordinary to North Carolina" and that a "number" of the proposed programs and projects were indistinguishable from normal activities.[8]

Q. DID THE COMMISSION OFFER ANY INSTRUCTION TO DEC FOR THE TREATMENT OF SIMILAR EXPENSES IN THE FUTURE?

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6 Commission Order, Docket No. E-7, Sub 1146, page 19 (June 22, 2018).

7 *Ibid.*, page 146.

8 *Ibid.*

A. Yes. The Commission suggested that DEC either undertake a collaborative proceeding with an effort to reach stakeholder consensus on supported projects, seek "expedited consideration" of expenses incurred in advance of a rate case, or seek recovery through the traditional ratemaking processes.

Q. IS DEC'S DEFERRAL REQUEST HERE CONSISTENT WITH THE COMMISSION'S INSTRUCTIONS FROM THE LAST RATE CASE?

A. No. It does not appear to fit in any of these categories. Most significantly for purposes of the present proceeding, DEC has not represented that interested stakeholders support the specific investments proposed by DEC in this rate case. Further, its request for regulatory deferral is not an example of the "traditional ratemaking process."

Q. IS THE CONTENT OF THE GRID IMPROVEMENT PLAN SIMILAR TO THE CONTENT OF THE POWER/FORWARD CAROLINAS PLAN?

A. Yes. I have compiled Table 2 below comparing the Grid Improvement Plan in this case to DEC's previous Power/Forward Carolinas proposal. DEC has not provided evidence that distinguishes the nature of the Grid Improvement Plan investments from those proposed under Power/Forward Carolinas. Given the Commission's findings in the last rate case, I would have expected DEC to provide such evidence, if it existed, in its direct case. Given the similarities in expenses, my *prima facie* expectation is that the Grid Improvement Plan is not sufficiently different from customary T&D spend to justify a different regulatory treatment.[9] As I discuss

[9] As discussed above, I made the argument in the prior rate case that Power/Forward Carolinas was not sufficiently different from customary spend to merit a different regulatory treatment.

below, my review of the evidence presented in the current rate case confirms my *prima facie* expectation and leads me to the conclusion that the Grid Improvement Plan does not merit different regulatory treatment.

Table 2: Similarity Between Grid Improvement Plan and Power Forward Carolinas

Program Category from Power/Forward Carolinas[10]	Power/Forward Carolinas Description[11]	Grid Improvement Plan Description
Targeted Underground (TUG)	Converting heavily-treed neighborhoods prone to power outages from overhead to underground construction to decrease outages, reduce momentary interruptions (blinks), improve major storm restoration time, and improve customer satisfaction.	The TUG program strategically identifies Duke Energy's most outage prone overhead power line sections and relocates them underground to reduce the number of outages experienced by customers. (Oliver Exhibit 4, page 19 of 52)
Distribution Hardening & Resiliency	Upgrading equipment to lower system outage risk due to asset failure (hardening) and to minimize the impacts of events and improve ability to recover rapidly when events occur (resiliency). This program also addresses asset end-of-life opportunities, system design, and physical and cyber security.	The Distribution System Automation program improves how the distribution system protects the public and itself from unsafe voltage and current levels and significantly reduces the impact experienced by customers due to grid issues. (Oliver Exhibit 4, page 10 of 52) The Long Duration Interruption/High Impact Sites program is designed to improve the reliability for parts of the grid with high potential for long duration outages as well as for high-impact customers like airports and hospitals. (Oliver Exhibit 4, page 16 of 52)

10 Source for Power/Forward Carolinas Program Categories: Table 2 of my direct testimony in the previous DEC rate case. *See* Docket No. E-7, Sub 1146, Kurt Strunk Direct Testimony.

11 Source for Power/Forward Carolinas Descriptions: *Ibid*.

Program Category from Power/Forward Carolinas[10]	Power/Forward Carolinas Description[11]	Grid Improvement Plan Description
		The Distribution Hardening & Resiliency – Flooding program focuses on hardening lines and structures as a balanced approach that can keep power and critical services available to some portion of a community and prevent a widespread outage in an area until flooding recedes. (Oliver Exhibit 4, page 23 of 52)
		The Physical and Cyber Security program protects against the potential risks and impacts of attacks on the electric grid. (Oliver Exhibit 4, page 41 of 52)
Transmission Improvements	Deploying equipment upgrades, flood mitigation, physical and cyber security, and system intelligence to make a smarter, more reliable and secure transmission system.	The Transmission Hardening & Resiliency program works to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events, natural or man-made. (Oliver Exhibit 4, page 35 of 52)
		The Transmission System Intelligence program deploys transformational system monitoring and control equipment to enable faster response to outages and more intelligent analysis of issues on the grid. (Oliver Exhibit 4, page 33 of 52)

Program Category from Power/Forward Carolinas[10]	Power/Forward Carolinas Description[11]	Grid Improvement Plan Description
Self-Optimizing Grid (SOG)	Applying modernization investments to build a more resilient distribution system better able to isolate problems and re-route power to minimize impacts to our customers and communities. To enable SOG functionality, circuits will have automated switches approximately every 400 customers, or 2 MW peak load, or 3 miles in circuit segment length.	The SOG program, also known as the smart-thinking or self-healing gird, implements distribution system design guidelines that improve grid reliability and resiliency. SOG circuits will have automated switches to divide the circuit into switchable segments. Each segment is designed to consist of approximately 400 customers, three miles in circuit segment length, or serve 2MW of peak load. (Oliver Exhibit 4, page 7 of 52)
Advanced Metering Infrastructure (AMI)	Deploying digital smart meters and associated communication devices to provide enhanced customer billing and payment options, detailed usage data, and energy-savings tools, as well as enhanced operational functions such as automated meter-reading, remote service connections and outage detection.	The Smart Meter program is a metering solution (meters, communication devices and networks, and back office systems) used to create two-way communications between customer meters and the utility. Smart meters are digital electricity meters that have advanced features and capabilities beyond traditional electricity meters. Some of the advanced features include interval usage measurement, tamper detection, voltage and reactive power measurement, and net metering capability. (Oliver Exhibit 4, page 26 of 52)

Program Category from Power/Forward Carolinas[10]	Power/Forward Carolinas Description[11]	Grid Improvement Plan Description
Communication Network Upgrades	Providing high-speed, high bandwidth, secure communications pathways (fiber optic and wireless) for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems.	The Enterprise Communications program includes improvement and expansion of the entire communications network from the high-speed, high-capacity backbone fiber optic and microwave networks to the wireless connections at the edge of the grid. These upgrades help build the secure communications required for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems. (Oliver Exhibit 4, page 45 of 52)
Advanced Enterprise Systems	Upgrading systems that manage grid devices, monitor equipment health, analyze data from monitoring sensors to improve system operations and maintenance activities, and enable grid self-optimizing technologies.	The Enterprise Applications program deploys the systems and upgrades needed to monitor the health and security of the grid and analyze data to enable grid automation and optimization technologies. (Oliver Exhibit 4, page 48 of 52)

Q. HOW MUCH MONEY IS DEC SEEKING TO RECOVER THROUGH THIS DEFERRAL MECHANISM?

A. DEC provided a North Carolina Grid Improvement Plan budget of $2.3 billion for 2020 to 2022, of which $1.3 billion is allocated to DEC.[12] Of this amount, DEC seeks approval to defer over $1.2 billion of capital expenditures, which is a significant amount of money for a company of DEC's size to defer, over a relatively

[12] *See* Oliver Direct Testimony, Exhibit 10, page 3.

short period of three years.[13] The Grid Improvement Plan capital expenditures proposed for deferral alone represents eight percent of DEC's rate base.[14] To be clear, the Grid Improvement Plan represents future spending in addition to the T&D costs DEC seeks to recover in the current rate case. These grid investments are part of a larger capital plan in which DEC budgets approximately $9.1 billion,[15] or approximately 60 percent of DEC's existing rate base. The actual amount DEC would defer would be even higher, once O&M and return on capital expenditures for Grid Improvement Plan projects are included – DEC seeks to defer these costs too.

DEC Witness McManeus also references that the Commission could authorize deferral of grid modernization costs incurred prior to the test year.[16] I do not know specifically which costs incurred prior to the test year DEC may seek to defer.

Q. WHAT CRITERIA DOES DEC BELIEVE SHOULD APPLY IN EVALUATING THE REQUEST FOR DEFERRAL ACCOUNTING?

A. In response to Tech Customers Data Request 4-5,[17] DEC explains:

> As noted in the Company's petition in Docket No. E-7, Sub 1181, page 16, "the Commission has often applied a two-prong test to consider whether a requested cost deferral is justified: (1) whether the costs in question are

[13] DEC Response to Tech Customers Data Request 4-17, and the attached printout titled "Capital Spend and Installation O&M Estimatd," at cell F54, from the "McManeus Grid Deferral Estimate Spreadsheet" (attached as Exhibit KGS 2)

[14] DEC's proposed original cost rate base for North Carolina retail operations is $15.5 billion, after accounting adjustments and proposed increases. *See* McManeus Direct Testimony, Exhibit 1, line 13, column 6.

[15] *See* McManeus Direct Testimony, page 39, line 18.

[16] *Ibid.*, page 40, line 22 to page 41, line 2.

[17] Exhibit KGS 3.

> unusual or extraordinary in nature, and (2) whether, absent deferral, the costs would have a material impact on the utility's financial condition."

Q. IS THE TWO-PRONGED TEST PREVIOUSLY USED BY THE COMMISSION A REASONABLE APPROACH FOR EVALUATING A REQUEST FOR DEFERRAL ACCOUNTING?

A. Yes, the test is a reasonable one for evaluating the request for deferral accounting. In my experience, deferrals typically occur when the particular costs are unusual, extraordinary, or unpredictable and also are large enough that expensing of the costs—without deferral accounting—would harm the utility's financial condition.

Q. DID DEC PRESENT COMPELLING EVIDENCE TO SUPPORT ITS CLAIM THAT THE PROPOSED DEFERRALS MEET THE COMMISSION'S TWO-PRONGED TEST?

A. No. DEC did not present compelling evidence to establish that the costs proposed for deferral meet the two-pronged test. In fact, DEC has not proven its case that the deferral request meets either of the prongs.

A. <u>DEC Has Not Distinguished the Grid Improvement Plan Investments from its Other Transmission and Distribution Investments.</u>

Q. ARE THE GRID IMPROVEMENT PLAN INVESTMENTS "UNUSUAL OR EXTRAORDINARY IN NATURE"?

A. No. The Grid Improvement Plan investments appear similar, if not identical, to the type of investment that DEC routinely makes in its transmission and distribution systems. While DEC alleges that "expenditures to be made under the Grid Improvement Plan are not simple, regularly occurring, inconsequential investments, but rather, are major non-routine investments, that produce substantial customer benefits,"[18] DEC's descriptions of the types of investments in the Grid Improvement Plan do not support its claim that they are out of the ordinary. DEC places its proposed Grid Improvement Plan investments into three categories: (1) compliance-driven programs that protect the grid, (2) grid modernization with rapid technology advancement programs, and (3) optimization of the customer's experience.[19] DEC has not demonstrated that any of these categories meet the criterion that they are unusual or extraordinary in nature.

DEC acknowledges similarities in the proposed investments through the Grid Improvement Plan and regular T&D spend, as the following data request and answers show:[20]

- *Question*: "Does DEC's anticipated go-forward base T&D spend (*e.g.*, not part of the Grid Improvement Plan) include projects that comply with obligations to protect the grid?" *Answer*: "Yes"
- *Question*: "Does DEC's anticipated go-forward base T&D spend (*e.g.*, not part of the Grid Improvement Plan) include projects that utilize 'new' or 'modern' T&D technologies (*e.g.*, T&D technologies not available or not commonly utilized a decade ago)?" *Answer*: "Yes"
- *Question*: "Does DEC's anticipated go-forward base T&D spend (e.g., not part of the Grid Improvement Plan) include projects and programs that optimize the customer's experience?" *Answer*: "Yes"

[18] McManeus Direct Testimony, page 39, lines 8-11.

[19] Oliver Direct Testimony, page 34, lines 9-12.

[20] Responses to Tech Customers Data Request 6-9 (attached as Exhibit KGS 4).

Q. DO YOU HAVE ADDITIONAL EVIDENCE OF LACK OF SPECIFICITY IN THE SEPARATION OF CUSTOMARY TRANSMISSION AND DISTRIBUTION SPEND *VERSUS* INVESTMENTS IN THE GRID IMPROVEMENT PLAN?

A. Yes. Additional DEC's responses to data requests show overlap between expenditures in regular transmission and distribution spend and in Grid Improvement Plan spend:

- *Expanded energy storage capabilities and infrastructure.* Witness Oliver's testimony states that the Grid Improvement Plan includes such investments.[21] In response to Tech Customers Data Request 6-1,[22] DEC indicates that energy storage costs may also be part of regular spend. However, DEC provides no indication as to how the line is to be drawn between what is deferred and what is not.[23]
- *Voltage optimization and distribution of power to customers.* Witness Oliver's testimony also states that these investments are part of the Grid Improvement Plan.[24] However, in its response to Tech Customers Data Request 6-2(d),[25] DEC confirms that voltage optimization costs are also found within those

[21] Oliver Direct Testimony, page 12, lines 6-8.

[22] Exhibit KGS 5.

[23] DEC states in its response to Tech Customers Data Request 6-1 (attached as Exhibit KGS 5): "DEC will determine the appropriate cost recovery mechanisms on a case by case basis" (6-1(a)) and "DEC intends to recover costs associated with battery storage projects that have significant local reliability benefits in the same manner as other prudent investments needed to serve customers through general rate cases, or other rate recovery mechanisms as may be approved by the Commission" (6-1(b)).

[24] Oliver Direct Testimony, page 12, lines 12-14.

[25] Exhibit KGS 6.

routine grid expenditures that are not part of the Grid Improvement Plan. While DEC tries to distinguish the Grid Improvement Plan investments based on whether the equipment communicates with a control center,[26] this assertion is not compelling as DEC suggests that at least some of existing equipment already communicates with a control center and no deferral accounting or rider treatment was necessary for DEC to install that equipment.[27] Further, the distinction itself (whether equipment communicates with a control center) appears arbitrary: no compelling reason is given why one type of voltage optimization costs should be considered unique so as to justify deferral.

- *Upgrading breakers, transformers, and other grid equipment, as well as … strategically underground[ing] the most vulnerable, outage-prone lines on the distribution system*. DEC acknowledged that these investments, which it lists as part of the Grid Improvement Plan,[28] have also been made and are part of the test year rate base.[29] Thus, DEC has already made these investments without deferral, yet seeks to defer go-forward costs of this sort.

Q. ARE THERE OTHER EXAMPLES OF GRID IMPROVEMENT PLAN INVESTMENTS THAT HAVE PREVIOUSLY BEEN TREATED AS CUSTOMARY SPEND?

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[26] *See* DEC's Response to Tech Customers Data Request 6-18(b) (attached as Exhibit KGS 7).

[27] DEC states: "Today, *much* of this equipment operates independently and does not communicate to a central control system." *Ibid*. (emphasis added). However, even if much of the equipment does not communicate with a control system, at least some does.

[28] Oliver Direct Testimony, page 12, lines 10-12.

[29] In response to Tech Customers Data Request 6-19(b) (attached as Exhibit KGS 8), DEC states: "[y]es, upgrading breakers, transformers, and other grid equipment and strategically undergrounding wires were part of the investments included in the test year in this case."

A. Yes. In response to Tech Customers Data Request 8-2,[30] DEC admits that the "Breaker Replacement Program" and the "Transformer Bank Replacement Program" on the transmission system and its "Transformer Retrofit Program" on the distribution system are part of DEC's historical base maintenance spend that overlaps with proposed Grid Improvement Plan spending.[31] Although some of these may fall into categories already mentioned, again the question arises as to why these investments should be considered unusual or extraordinary.

Q. PLEASE ADDRESS DEC'S ARGUMENT THAT THE DEFERRAL OF GRID IMPROVEMENT PLAN INVESTMENTS IS NECESSARY TO RESPOND TO MEGATRENDS IN THE ELECTRIC POWER INDUSTRY.

A. DEC attributes the need for the Grid Improvement Plan to respond to various "Megatrends" in the electricity sector.[32] However, the electricity sector has and

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[30] Exhibit KGS 9.

[31] While DEC's response to this data request seeks to differentiate the Grid Improvement Plan from traditional transmission and distribution spending, it contains specific examples of categories of expenditures that DEC admits used to be regular spend but DEC now classifies as part of the Grid Improvement Plan costs subject to deferral accounting.

[32] *See* Oliver Direct Testimony, Section II. Mr. Oliver lists seven Megatrends:

1. "Population and business growth continues in North Carolina and is heavily concentrated in urban and suburban areas;
2. Technology is advancing at a rapid rate in the areas of renewables and distributed energy resources ('DERs'), which means there are new types of load and resources impacting the grid;
3. Technology is also advancing rapidly within the devices and systems that operate and manage the T&D grids, offering new capabilities and requiring new functionalities;
4. Customer expectations and use of the grid are very different from generations past;
5. There has been an increase in environmental commitments from the international to local level in DE Carolinas' service territory;
6. The number, severity and impact of weather events on DE Carolinas' customers has been increasing significantly; and

will continue to undergo change and Mr. Oliver's "Megatrends" are not likely to be a temporary phenomenon.

These Megatrends are nothing new; they have impacted the electricity and utility sectors for decades, even if DEC has only recently begun to label them Megatrends. Further, the trends are not going away: Witness Oliver agrees the trends will continue into the future.[33] DEC has presumably spent money on transmission and distribution infrastructure that address issues raised by the Megatrends over the last 10 to 20 years (*i.e.*, before the Grid Improvement Plan was created), and DEC will continue to invest in similar projects after the end of its current proposed Grid Improvement Plan in 2022. Megatrends are likely to continue for the foreseeable future and DEC's spending in response may continue indefinitely.[34] The very nature of Megatrends is that utilities must address them as part of their prudent utility planning and practices. These sorts of systemic "influencers" identified by DEC are the opposite of "unusual or extraordinary" factors that typically justify deferral accounting.

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7. The threat of physical and cyber-attacks on grid infrastructure is more sophisticated and is on the rise."

Oliver Direct Testimony, page 28, line 15 to page 29, line 6.

[33] *See* DEC response to Tech Customers Data Request 10-2 (attached as Exhibit KGS 10). While DEC's response references a relatively short history for the Megatrends, I disagree and believe these trends have been present for a longer time in the utility sector.

[34] When asked about grid improvement costs beyond 2020, DEC responded that it "does not know whether it will seek other deferrals for costs related to grid improvement in the future" and "has not developed any future phases of the Grid Improvement Plan and thus cannot speculate as to how any such costs would be recovered." DEC Response to Tech Customers Data Requests 6-5(d) and 6-5(e) (attached as Exhibit KGS 11). While DEC may not want to commit at this point to future costs it has yet to plan for, such responses as these do not help the Commission determine whether Grid Improvement Plan costs are "unusual or extraordinary in nature."

B. <u>DEC Has Not Established Negative Financial Effects of Traditional Regulatory Treatment for the Grid Improvement Plan.</u>

Q. PLEASE ADDRESS THE SECOND PRONG OF THE COMMISSION'S TEST – THE NEGATIVE FINANCIAL EFFECT ON DEC.

A. DEC Witness McManeus addresses the financial effect in the event that the Commission does not approve a deferral. Ms. McManeus testifies that: "absent deferral the Company will experience a significant adverse earnings impact. The earnings degradation is expected to grow to over 100 basis points by 2022, the third year of the plan."[35]

However, DEC's analysis that supports Ms. McManeus's 100 basis point calculation is flawed in two critical ways.[36] First, the analysis assumes that the Company's grid improvement investments will be the same amount (and on the same timeframe) irrespective of whether the Commission approves the deferral. Second, the analysis looks at the grid improvement investments in isolation, without considering how other elements of DEC's balance sheet and income statement will evolve.

Q. WHY IS IT INAPPROPRIATE FOR MS. MCMANEUS TO ASSUME THE LEVEL AND TIMING OF INVESTMENT IS THE SAME WITHOUT DEFERRAL?

A. It is inappropriate because it is contradicted by her colleague, DEC Witness Mr. Oliver, who suggests that DEC would spend less on its Grid Improvement Plan

[35] McManeus Direct Testimony, page 39, lines 11-14.

[36] See the attached printout of the spreadsheet titled "NC Retail ROEs Reported in E.S.-1 and Impacts of Potential Adjustments" from McManeus Grid Deferral Estimate Spreadsheet (attached as Exhibit KGS 2).

without deferral, or at least spread out the investment over a much longer time. Mr. Oliver states:

> [I]f the Commission determines not to grant the regulatory asset treatment for the Company's Grid Improvement Plan investment sought in this proceeding, the Company will be required to reassess its ability to implement that plan. In such a situation, **the Company would have to try and perform small pieces of the Grid Improvement Plan over a much longer period with its existing revenues**, which will delay important benefits and potentially essential improvements for customers.[37]

In addition to addressing the level of investment, this quote shows that Mr. Oliver is raising a separate point, the allegation that delaying Grid Improvement Plan expenditures (caused by a lack of deferral) will "delay important benefits and potentially essential improvements for customers." Yet, as I address later in my testimony, DEC does not adequately support this argument that a lack of deferral would harm customers as such.

Q. WHY IS IT INAPPROPRIATE FOR MS. MCMANEUS TO FOCUS ON THE LACK OF DEFERRAL WITHOUT CONSIDERING THE COMPANY'S ENTIRE FINANCIAL SITUATION?

A. Ms. McManeus's isolation of the grid improvement effect is inappropriate because it ignores the natural reduction in rate base for the existing asset portfolio that occurs over time due to depreciation. It also does not account for other changes in costs that may affect DEC's overall cost of service.

Q. PLEASE EXPLAIN WHY RATE BASE FOR DEC'S EXISTING ASSET PORTFOLIO SHOULD BE EXPECTED TO DECLINE.

[37] Oliver Direct Testimony, page 54, line 23, to page 55, line 4 (emphasis added).

A. Traditional ratemaking practice in the United States front loads cost recovery for regulated utility investments. When DEC puts an asset into service, the regulatory process affords the utility a rate a return on the full cost of the asset, as reflected in its book value. As DEC depreciates that asset over time, the net book value declines and the return component of the utility's revenue requirement related to that asset declines in parallel. This results in a lower revenue requirement, all else equal.

Q. IS IT POSSIBLE THAT THE NATURAL DECLINE IN REVENUE REQUIREMENT COULD BE MORE THAN OFFSET BY INCREASES IN NEW INVESTMENTS OR INCREASES IN OTHER COSTS?

A. Yes. In principle, a utility's new investments can be so large as to offset the declining rate base phenomenon. Changes in operating costs can also lead to revenue requirement increases (or reductions). The analysis that supports Ms. McManeus's 100 basis point statement isolates the cost of the Grid Improvement Plan without considering changes in other costs. An example of potential sources of savings from grid improvement may be a reduction in kilowatt-hour losses on the power grid. DEC's analysis of the financial effect does not account for these potential savings or any others.

Q. ARE OTHER PATHS OF ACTION AVAILABLE TO THE UTILITY TO MITIGATE ANY NEGATIVE EFFECT ON EARNINGS IF SUCH AN EFFECT WERE TO MATERIALIZE?

A. Yes. DEC could seek rate relief from the Commission should the negative effect on earnings materialize. If the earnings loss were large, it would be reasonable to expect that the utility would not simply absorb the earnings loss but would instead apply to the Commission for rate relief. DEC's analysis supporting Witness McManeus assumes that DEC will not seek rate relief yet will continue to make the investments.

In addition, DEC could delay certain Grid Improvement Plan investments, as DEC Witness Oliver assumes it would do if the Grid Improvement Plan does not receive deferral treatment.

Q. ARE YOU SUGGESTING THAT DEC SHOULD FOREGO CRITICAL INVESTMENTS NEEDED TO MAINTAIN RELIABILITY?

A. No. I am not suggesting foregoing critical investment needed for reliability. I am simply recognizing that the existing regulatory framework has been adequate for DEC to make the transmission and distribution investments necessary to maintain reliability. DEC has not established that a departure from that regulatory framework is necessary.

Q. YOU NOTED THAT MR. OLIVER'S TESTIMONY STATES THAT NOT ALLOWING DEC TO DEFER GRID IMPROVEMENT PLAN COSTS WOULD CAUSE DEC TO MAKE THESE INVESTMENTS IN SMALL PIECES OVER A LONGER TIME FRAME, CAUSING "DELAY [TO] IMPORTANT BENEFITS AND POTENTIALLY ESSENTIAL IMPROVEMENTS FOR CUSTOMERS." PLEASE ADDRESS WHETHER DEC HAS ADEQUATELY SUPPORTED THIS ASSERTION.

A. It has not. DEC admits that it has not analyzed which Grid Improvement Plan projects it would undertake nor the timing of those projects if it is unable to defer

Grid Improvement Plan costs.[38] Without this sort of analysis, any conclusions DEC might offer regarding the effect on customers of DEC not being able to defer Grid Improvement Plan costs are unsupported conjecture. As discussed above, traditional ratemaking has allowed DEC to provide a reliable grid for its customers for decades, and I have seen no compelling evidence that deviating from traditional ratemaking is required for DEC to deliver a reliable grid to its customers over the next several years.

Even to the extent that DEC would choose to delay some Grid Improvement Plan projects in the absence of deferral, DEC has not performed a holistic assessment of the effect this would have on customers. As DEC admits, customer rates will rise—all else being equal—if DEC spends the amounts it expects to spend to implement the Grid Improvement Plan.[39] Yet, DEC has not analyzed whether customers are better off, on balance, given the trade-off between higher rates and any benefits from Grid Improvement Plan programs occurring as DEC plans.[40]

While DEC has produced various Cost-Benefit Analyses ("CBAs") to support its application,[41] DEC's analyses are flawed in several respects. First, the CBAs do not incorporate customer preferences for lower electric rates. Second, the

[38] DEC's response to Tech Customers Data Request 6-15(a) (attached as Exhibit KGS 12).

[39] DEC's response to Tech Customers Data Request 6-11(e) and 6-12(e) (attached as Exhibits KGS 13 and KGS 14).

[40] DEC's responses to Tech Customers Data Requests 6-11 and 6-12 (attached as Exhibits KGS 13 and 14, respectively). While DEC's response to Data Request 6-12 directs the reader to the cost-benefit analyses it has performed, those analyses do not assess the effect of higher rates on customers, but rather look at costs to DEC to carry out the associated Grid Improvement Plan projects.

[41] *See* Oliver Direct Testimony, Exhibit 7.

CBAs appear not to incorporate the negative effects on the economy of raising rates for customers. Without incorporating these factors, DEC cannot justifiably conclude customers are better off with deferral. Finally, I note that the DEC analysis attributes to the Grid Improvement Plan *indirect* benefits that amount to $7 billion for the entire Grid Improvement Plan (or that portion of it for which DEC performed CBAs).[42] While these indirect benefits are a smaller share of the estimated benefits than they were for the Power/Forward Carolinas plan, the indirect benefits are still large and appear speculative.

C. While Regulatory Deferrals Can be Appropriate in Certain Situations, Deferring Grid Improvement Plan Investments Unduly Tilts the Regulatory Balance.

Q. WHAT EFFECT WOULD THE PROPOSED DEFERRAL HAVE ON DEC CUSTOMERS?

A. Deferral accounting transfers risks from DEC to its customers and will raise customer rates to the benefit of DEC. Under deferral accounting, DEC can place Grid Improvement Plan costs into a regulatory asset account, including depreciation, return on capital investments (net of depreciation), and O&M expenses related to Grid Improvement Plan projects. DEC then earns a return on this regulatory asset.

Q. IS SUCH A REGULATORY MECHANISM APPROPRIATE FOR TRULY EXTRAORDINARY COSTS?

[42] *See* Oliver Direct Testimony, Exhibit 8, page 3, Total IMPLAN Benefits for Total Portfolio.

A. Yes. It is not my professional opinion that regulatory deferrals are always inappropriate. Rather, the specific circumstances DEC has presented to the Commission relating to the costs of its proposed Grid Improvement Plan do not merit approval of a regulatory deferral. As explained above, the Grid Improvement Plan costs are not sufficiently differentiated from regular investments to warrant deferral treatment, and DEC has not established the negative financial effects on the utility.

D. <u>DEC's Grid Improvement Plan Puts the Cart Before the Horse as DEC is Currently Studying Integrated Planning</u>

Q. ARE YOU AWARE OF EFFORTS BY DEC TO IMPROVE ITS PLANNING PROCESSES?

A. Yes. I understand that DEC is considering how it can improve its Integrated Resource Plans ("IRPs")—traditionally undertaken for generation and transmission investments—by accounting for new distributed energy resources ("DERs") that interconnect to the distribution system and technology-enabled demand response. I further understand that DEC is at the planning stages of implementing what it calls Integrated Systems and Operations Planning ("ISOP"). DEC describes this effort as follows:

> ISOP is intended to be an integral part of the IRP in the future, complementing existing IRP tools and processes. The objective is to progressively improve analysis of potential system impacts and benefits of distributed energy resources (DERs) and new customer programs as technology advances over time. **Duke Energy views this as a necessary evolution to address trends in the development of DER technology, declining cost projections of these technologies, changing customer preferences, and planning needs in the future for an increasingly**

> **dynamic grid.** To be clear, the ISOP effort is not prejudging the analytical outcome of comparing DERs to central station generation. The effort is intended to provide the methodology and tools to enable a fair and thorough comparable evaluation reflecting all practical sources of value.[43]

Q. COULD ISOP AFFECT THE LEVEL AND NATURE OF INVESTMENT REQUIRED UNDER DEC'S GRID IMPROVEMENT PLAN?

A. Yes. While it is difficult to prejudge the outcome, it is reasonable to expect that DEC may gain information and insight through the ISOP process that will affect the nature and scope of the investments needed at the distribution level and, as a result, potentially, at the transmission level, affecting DEC's planning decisions. It appears premature, in this context, for the Commission to approve a deferral program—amounting to over $1 billion of new transmission and distribution investments that that may prove to be suboptimal but would nevertheless be deferred and carried on DEC's books at ratepayers' expense.

Q. DOES DEC DENY THE INTERACTION BETWEEN THE ISOP AND THE INVESTMENT PROPOSED UNDER DEC'S GRID IMPROVEMENT PLAN?

A. Yes. In response to Tech Customers Data Request 9-2,[44] DEC states that the "benefits of the investments proposed in this proceeding are not predicated on the integration of distribution, transmission and generation planning." While they may not be predicated on integrated planning, logically, the lessons from ISOP could

[43] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to July 23, 2019 Order Scheduling Technical Conference and Requiring Responses to Commission Questions, Docket No. E-100, Sub 157, August 21, 2019 (page 1) (emphasis added).

[44] Exhibit KGS 15.

and should help shape the Company's grid improvement strategy. DEC does not adequately explain why it believes its proposed investments in grid improvement are unrelated to ISOP.

V. DEC'S REQUESTED COST OF CAPITAL IS EXCESSIVE, INTERNALLY INCONSISTENT, AND SHOULD BE REJECTED.

Q. ON WHAT REGULATORY AND LEGAL FRAMEWORK DO YOU BASE YOUR COST-OF-CAPITAL ANALYSIS?

A. A key tenet in the determination of just and reasonable rates is that owners of regulated companies must be afforded a reasonable opportunity to earn a fair return on their invested capital. Fair return is thus an essential component of a regulated company's cost of service.

In administrative law proceedings in the United States, the practice of determining "fair return" is guided by the landmark Supreme Court decisions in *Federal Power Commission et al. v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) and *Bluefield Water Works & Improvement Co. v. Public Service Comm'n,* 262 U.S. 679 (1923). These decisions establish that fair return must be sufficient to attract capital and must compensate investors at a level consistent with returns on investments of comparable risk. In *Bluefield*, the Supreme Court held:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or

> anticipated in highly profitable enterprises or speculative ventures.[45]

In *Hope*, the court found:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[46]

Rates of return that compensate investors for opportunity costs and permit utilities to attract capital are a cornerstone of regulatory practice in the United States.

Q. WHAT COST OF CAPITAL IS DEC SEEKING IN THIS PROCEEDING?

A. The testimony of DEC witness Robert Hevert recommends an ROE of 10.50 percent, which compares to the recommendation of 10.75 percent he made in Docket No. E-7, Sub 1146. The 10.50 percent recommendation falls in the middle of his purported range of reasonableness of 10.00 percent to 11.00 percent. His recommendation represents a proposed 60 basis point increase from the currently approved ROE of 9.90 percent.

Although Mr. Hevert testifies that the 10.50 percent is the return required under *Hope* and *Bluefield*, the Company has elected to use a lower rate, 10.30 percent, when formulating the proposed 9.2 percent increase to base rates. That the Company's requested ROE is below Mr. Hevert's recommendation is evidence that Mr. Hevert is placing the ROE at a level above the ROE that DEC requires.

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[45] 262 U.S. at 692–93.

[46] 320 U.S. at 603.

Q. HOW DOES DEC WITNESS HEVERT ARRIVE AT HIS COST OF CAPITAL RECOMMENDATION?

A. Mr. Hevert performs financial analyses for a proxy group of nineteen publicly-traded electric utility companies. He relies upon the results of these analyses together with his judgment to identify a range of what he contends are reasonable returns and then selects a recommended ROE within the range. I note that the recommended ROE is at the high end of Mr. Hevert's analytical results.

Q. HAS DEC WITNESS HEVERT PROVIDED AN ANALYSIS OF THE RISKS OF DEC AS COMPARED TO THE RISKS OF THE UTILITIES IN HIS PROXY GROUP?

A. He has provided his opinions, but no real analysis. In his testimony, he cites two factors that he contends make DEC riskier than the proxy group. These are:

(1) The risks associated with certain aspects of the Company's generation portfolio; and

(2) The Company's significant capital expenditure plan.

Mr. Hevert clarifies that his concerns about the risk of the generation portfolio are tied to (a) environmental regulations, (b) coal-fired generation, (c) nuclear generation, and (d) renewable energy and energy efficiency portfolio standards in North Carolina.

Q. IS IT APPROPRIATE FOR MR. HEVERT TO ASSIGN A HIGHER RISK PROFILE TO DEC AS COMPARED TO THE PROXY GROUP?

A. No. Mr. Hevert's analysis is purely based upon his judgment and is not tied in any way to objective metrics. When asked whether he had performed a comparative analysis of the generation portfolio risks in the proxy group companies and within

DEC, he responded that he had not. When asked whether he had performed a comparative analysis of the capital expenditure risks for the proxy group companies and for DEC, he responded that he had not.[47]

Q. HAVE YOU ANALYZED DATA THAT CAN HELP THE COMMISSION TO DETERMINE THE RELATIVE RISK OF DEC AS COMPARED TO THE PROXY GROUP?

A. Yes. I have reviewed objective metrics in the course of the preparation of my testimony. The metrics indicate that DEC is *less* risky than the proxy group, not riskier, as elaborated below. Accordingly, the ROE Mr. Hevert recommends is excessive and should be rejected.

A. <u>Witness Hevert Recommends a Return on Equity that Is at the Top of the Range of Returns Recently Allowed by State Regulators</u>

Q. HAVE YOU COMPARED MR. HEVERT'S PROPOSED ROE TO THOSE OF OTHER ELECTRIC UTILITIES?

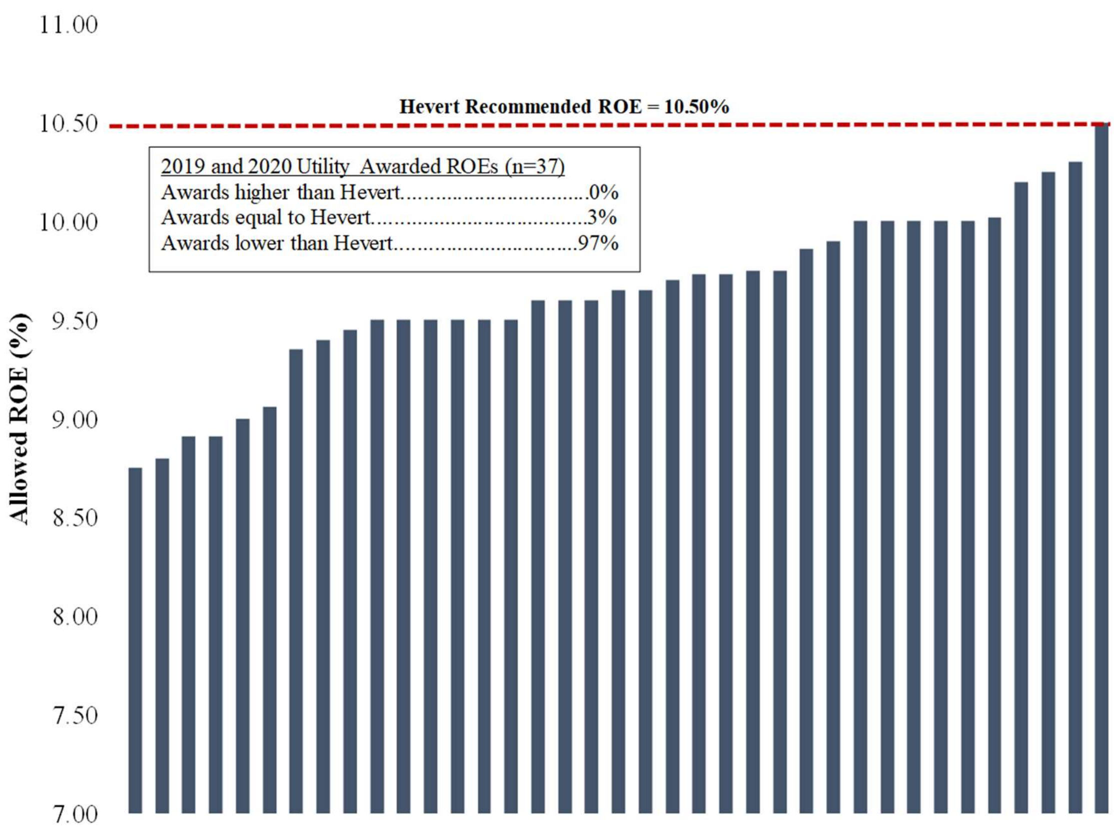
A. Yes, I have. I compared Mr. Hevert's proposed ROE to those that have been authorized for other vertically-integrated electric utilities across the country. As illustrated in

Figure 1 below, the proposed ROE of 10.5 percent is at the top of the range of allowed returns. The one ROE awarded at that level was made for Georgia Power in the context of a settlement and a three-year rate plan. As DEC is not entering into a three-year rate agreement, the Georgia Power example is not directly comparable

[47] Response to Tech Customers Data Request 2-1 (attached as Exhibit KGS 16).

to DEC's situation. The mean awarded ROE for this time period is 9.63 percent, while the median is 9.65 percent.[48]

Figure 1: Comparison of Hevert ROE to Industry Benchmarks



Source: Regulatory Research Associates.

B. <u>DEC's Equity Ratio Is Among the Highest Allowed in Regulatory Practice</u>

Q. WHAT EQUITY RATIO IS DEC SEEKING IN THIS PROCEEDING?

A. DEC witness Karl Newlin recommends a 53.00 percent equity ratio, arguing that that specific ratio minimizes the overall weighted-average cost of capital (at page 21)—yet he does not support that statement with any analytical evidence.

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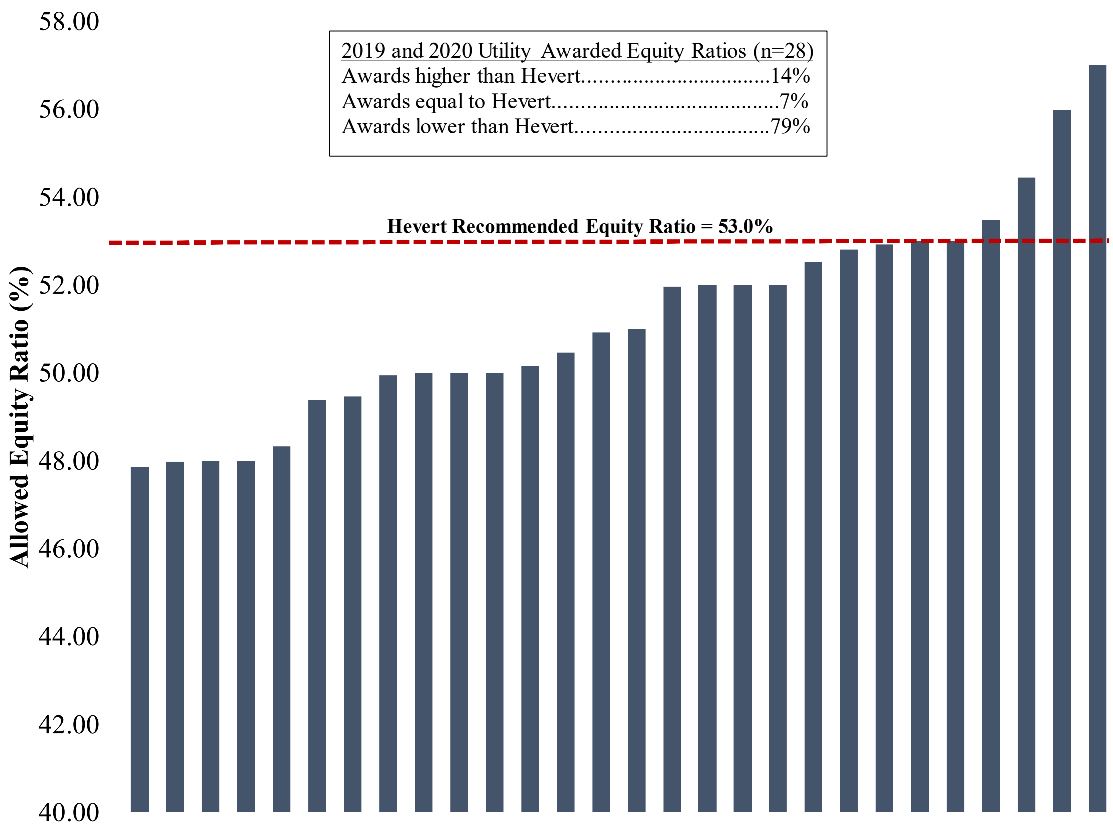
[48] Source for awarded ROEs: Regulatory Research Associates.

Q. HAVE YOU COMPARED DEC'S EQUITY RATIO TO THOSE OF OTHER ELECTRIC UTILITIES?

A. Yes, I have. I compared DEC's equity ratio to those authorized for other vertically-integrated electric utilities across the country. The mean equity ratio awarded was 49.29 percent and the median equity ratio awarded was 50.16 percent.[49] As illustrated in Figure 2 below, DEC's proposed equity ratio of 53.00 percent is above the mean and median equity ratio awarded, indicating low financial risk compared to other operating utilities.

Figure 2: Comparison of Hevert to Industry Benchmarks



Source: Regulatory Research Associates.

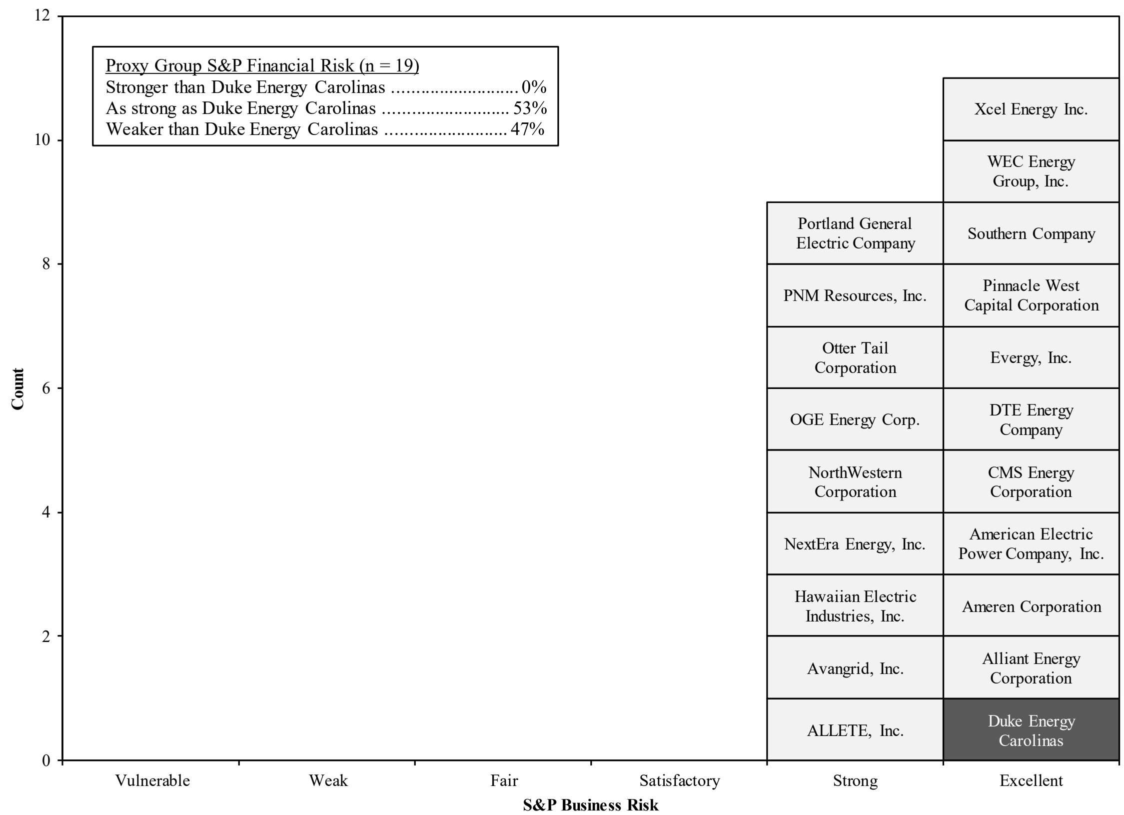
[49] Mean and median of allowed equity ratios presented in Figure 2.

C. DEC Has the Least Risky Business Risk Ranking from Standard & Poor's.

Q. HAVE YOU COMPARED BUSINESS RISK RANKINGS FROM S&P FOR DEC AND THE PROXY GROUPS?

A. Yes. Figure 3 below illustrates S&P's business risk ranking for DEC and for the companies of the proxy group. DEC maintains a ranking of "Excellent" from S&P, indicating very low business risk. Many of the proxy group companies fall in the category of "Strong," indicating higher levels of business risk than DEC faces.

Figure 3: Standard & Poor's Risk Rankings for DEC and Hevert Proxy Group Companies



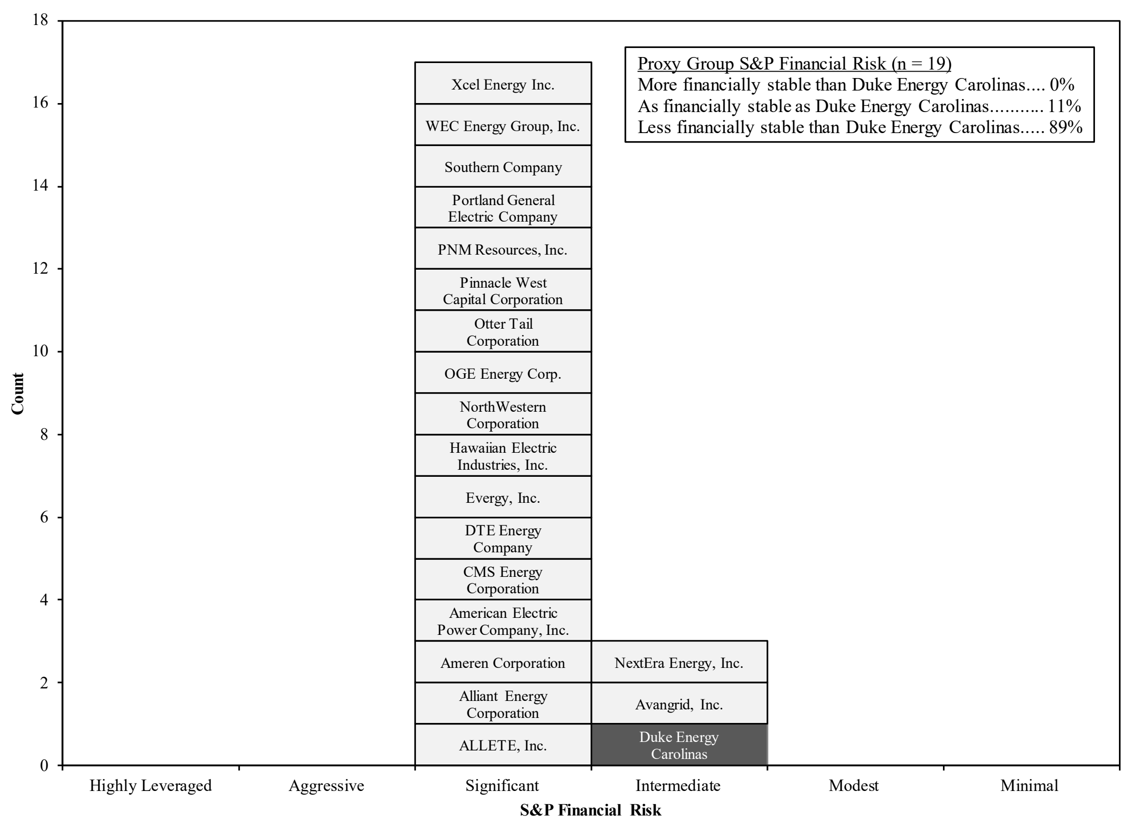
Source: Standard & Poor's Financial Services LLC

D. DEC Has Lower Financial Risk than Most of the Proxy Group Companies.

Q. HAVE YOU COMPARED FINANCIAL RISK RANKINGS FROM S&P FOR DEC AND THE PROXY GROUP COMPANIES?

A. Yes. Figure 4 below illustrates S&P's financial risk ranking for Duke Energy Carolinas and for the companies in Mr. Hevert's proxy group. DEC maintains a financial risk ranking of "Intermediate" from S&P. The vast majority—all but two—of the proxy group companies fall in the "Significant" financial risk bracket, indicating that they face higher levels of financial risk than DEC.

Figure 4: Standard & Poor's Risk Ranking for DEC and Hevert Proxy Group Companies



Source: Standard & Poor's Financial Services LLC

These objective metrics provided by financial analysts at Standard & Poor's—a company that routinely evaluates utility business and financial risks—support my finding that DEC presents lower risk than the proxy group companies, not a higher risk as Mr. Hevert contends.

Q. GIVEN THE EVIDENCE PRODUCED BY MR. HEVERT AND YOUR COMPARATIVE RISK ANALYSIS, WHAT IS A FAIR RETURN FOR DEC?

A. As discussed above, I disagree with Mr. Hevert's contention that DEC is relatively riskier than the proxy group. Accordingly, I conclude that the ROE range (10.00 percent to 11.00 percent) and specific recommendation (10.50 percent) he proposes are excessive and should be rejected. As evidenced in Table 3 below, Mr. Hevert's recommendation is above his range of ROE estimates for the proxy group. The only model that supports this high recommendation is the Empirical CAPM ("E-CAPM").

Table 3: DEC Witness Hevert ROE Estimates by Model[50]

METHOD	HEVERT ESTIMATE OF RETURN ON EQUITY
Constant Growth DCF	8.86 - 9.09%
Constant Growth DCF High	9.73 - 9.96%
CAPM w/ Bloomberg Beta Coefficient	8.68 - 8.80%
CAPM w/ Value Line Beta Coefficient	9.69 - 9.81%
ECAPM w/ Bloomberg Beta Coefficient	10.21 - 10.34%
ECAPM w/ Value Line Beta Coefficient	10.96 - 11.10%
Bond Yield Plus Risk Premium	9.90 - 10.06%

Q. DO MR. HEVERT'S E-CAPM RESULTS LOOK REASONABLE?

[50] Hevert Direct Testimony, page 12.

A. I do not take issue with the use of the E-CAPM model. However, I do note that Mr. Hevert's assumed market risk premium of 12.15 percent, taken together with his assumed risk-free rate of 2.63 percent, yields a total return on market investments of approximately 15 percent.[51] 15 percent is above the return that has been available to investors historically and it is questionable as to whether it is reasonable to assume investors will be able to earn a 15 percent return on the market going forward, particularly in light of the recent sustained run-up in stocks. As a result, the one model that supports the high end of Mr. Hevert's reasonableness range is likely overstating the true ROE.

Q. WHAT IS YOUR RECOMMENDATION FOR DEC'S ROE?

A. Given my analysis, I recommend that the Commission reject the ROE requested by the Company in favor of a lower ROE more in line with the lower risk profile of the Company as demonstrated by objective measures and the higher equity ratio DEC has sought. When determining where in this range to place the fair return, the Commission should take into consideration the lower risk of DEC relative to proxy group companies and the industry generally.

VI. *PRIMA FACIE* EVIDENCE SUGGESTS THAT DEC'S CONTINUED INVESTMENT IN COAL FACILITIES SLATED FOR EARLY RETIREMENT MAY BE IMPRUDENT

Q. DO YOU HAVE CONCERNS ABOUT DEC'S INVESTMENTS IN ITS COAL-FIRED GENERATION UNITS?

[51] Hevert Direct Testimony, Exhibit RBH-4, page 1.

A. Yes. I have high-level concerns about the reasonableness of DEC's decision to continue making investments in coal-fired generation units [redacted] While it is reasonable for DEC to be concerned for its investors—all utilities should be—it would not be reasonable for DEC to choose to operate a generation portfolio that is more costly than necessary, leading to higher customer rates. In this section of my testimony, I present *prima facie* evidence raising doubts about the prudency of DEC's investments. In the absence of further justification of the prudence of its decisions, I recommend the Commission not allow inclusion in rate base of the incremental capital expenditures at Allen Units 4 and 5, and Cliffside Unit 5 between the prior rate case and this one. The Commission also may wish to ask DEC to make an affirmative case for the prudence of DEC's investments in Marshall Units 1 & 2 (the retirement date for which has been accelerated) and of DEC's investments in any other coal units as the Commission sees fit.

Q. PLEASE DESCRIBE THE PRUDENCE STANDARD AS IT APPLIES IN U.S. REGULATORY PRACTICE.

A. In U.S. regulatory practice, the prudence standard has been articulated consistently from its inception and can be summarized as follows: prudence is what a reasonable person would do given information that is reasonably knowable at the time an expense is incurred. This reasonable person standard[52] is an integral part of cost-based regulation. Regulated utilities are entitled to recover costs, but such recovery is limited to costs that are prudently incurred and reasonable.

To judge whether a utility's decision making is prudent, regulators ask whether the decisions made by the utility are within the set of decisions that a reasonable person could have made given the information reasonably knowable at the time. There is no single course of action that is prudent. Rather there is a range of possible actions that meet the prudence standard.

Q. YOU HAVE TESTIFIED ON PRUDENCE BEFORE A VARIETY OF STATE REGULATORS. IN YOUR EXPERIENCE, DOES THE PRUDENCE STANDARD DIFFER ACROSS STATES?

A. In my experience, the standard is consistently characterized and applied by decision-makers in administrative law proceedings relating to public utility rates. The New York Public Service Commission, for example, has characterized the standard as follows:

> [T]he company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company.[53]

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[52] See, for example, Leonard Saul Goodman, *The Process of Ratemaking, Vol II,* 858 (1998).

[53] *In re Consolidated Edison Co. of N.Y. Inc.*, Opinion no. 79-1, 1979 WL 415126 (N.Y.P.S.C. Jan. 16, 1979).

Ultimately, the regulator must determine whether the decision resulted in "a reasonable and prudent business expense, which the consuming public may reasonably be required to bear."[54]

For its part, the California Public Utilities Commission (the CPUC) has articulated the standard for prudent managerial action in California:

> The term 'reasonable and prudent' means that at a particular time any of the practices, methods, and acts engaged in by a utility follows the exercise of reasonable judgment in light of facts known or which should have been known at the time the decision was made. The act or decision is expected by the utility to accomplish the desired result at the lowest reasonable cost consistent with good utility practices.
>
> A 'reasonable and prudent' act is not limited to the optimum practice, method, or act to the exclusion of all others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with the utility system needs, the interest of the ratepayers and the requirements of governmental agencies of competent jurisdiction.[55]

Q. HOW HAS THE PRUDENCE STANDARD BEEN APPLIED IN NORTH CAROLINA?

A. My review of North Carolina regulatory precedent indicates that this Commission, and the courts reviewing its decisions, have applied the standard I describe above. This Commission has articulated the prudence standard as follows:

> [T]he standard for judging prudence is "whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. … [T]his standard … must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis—the

[54] *Midwestern Gas Transm. Co. v. Fed. Power Comm'n*, 388 F.2d 444, 448 (7th Cir. 1968).

[55] CPUC Decision 87-06-021 (1987 Cal. PUC Lexis 588, *28-29; 24 CPUC 2d 476).

> judging of events based on subsequent developments—is not permitted."[56]

Q. WHAT MAKES YOU BELIEVE THAT IT MAY HAVE BEEN IMPRUDENT FOR DEC TO HAVE CONTINUED TO MAKE INVESTMENTS IN ITS COAL-FIRED GENERATION UNITS?

A. The following facts suggest that scrutiny of the decisions to evaluate prudence is warranted:

a. [redacted]

b. [redacted] This trend in declining economics, including unit retirements, is a national one that existed prior to 2016.

c. [redacted]

Q. [redacted]

A. [redacted]

[56] Commission Order, Docket No, E-7, Sub 1146, page 247 (June 22, 2018).

[redacted]

[redacted]

[redacted]

[redacted]

[57] "Cliffside Unit 5, Strategy Update," Slide 3 (Nov. 21, 2016) (attached as Exhibit KGS 17).

[58] *Ibid.,* Slide 6.

[redacted]

Q. IS THE UNFAVORABLE TREND IN COAL POWER PLANT ECONOMICS NATIONAL, AND, IF SO, HOW LONG HAS THIS TREND BEEN PREVALENT?

A. Yes, the unfavorable trend in coal power plant economics is national. While the precise timing of when this unfavorable trend began is up for debate, the trend extends back at least to 2010. Changes in the relative economics of coal power have led to significant retirements of coal-fired capacity and reductions in average capacity factors across the nation.

Q. WHAT DOES THE 2016 CLIFFSIDE PRESENTATION SAY ABOUT THE ECONOMICS OF RETIRING CLIFFSIDE UNIT 5 EARLY?

A. [redacted]

[redacted]

Q. [redacted]

A. [redacted]

[59] *Ibid*., Slide 12.

[60] DEC's 2019 IRP forecasts its winter reserve margin to be greater than 19 percent until 2025, more than its minimum planning reserve margin of 17 percent, and DEC forecasts its summer reserve margins to be even higher than its winter reserve margins. *See* Docket E-100 Sub 157, Duke Energy Carolinas, Integrated Resource Plan, 2019 Update Report, Public (Sept. 3, 2019): Page 10, Table 8-A (page 52), and Table 8-B (page 53).

[redacted]

[redacted]

Q. [redacted]

A. [redacted]

[61] I note a surplus of capacity overall in the SERC region, in which DEC operates, which could result in attractive purchases for DEC. See NERC, 2019 Long-Term Reliability Assessment, particularly pages 78, 80, and 82, which cover the SERC East, SERC Central, and SERC Southeast sub-regions, which have anticipated reserve margins of 24.0 percent, 39.8 percent, and 33.9 percent, respectively, for 2020. DEC operates principally in SERC East, and SERC Central and SERC Southeast are neighboring sub-regions. Document available here: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf. (SERC stands for the Southeastern Electric Reliability Council and NERC stands for North American Electric Reliability Corporation.)

[62] "Allen Station Retirement Options" (Mar. 28, 2017) (attached as Exhibit KGS 18).

[redacted]

Q. [redacted]

A. [redacted]

[63] *Ibid.*, Slide 5. [redacted]

[64] *Ibid.*, Slide 3. [redacted]

[redacted]

Q. [redacted]

A. [redacted]

Q. HOW WOULD THE EARLY RETIREMENT OF ALLEN UNITS 4 AND 5 HAVE AFFECTED DEC'S SPEND ON THE ALLEN UNITS?

A. [redacted]

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[65] *Ibid.*, Slide 11.

[66] *Ibid.*, Slide 3.

[redacted]

In summary, (a) had DEC made the decision to retire Allen Units 4 and 5 earlier, [redacted], DEC would have avoided more costs and (b) an alternative retirement date of 2023 ([redacted]) would have avoided more costs than retirement of Allen in 2024. DEC's costs to ratepayers would presumably be lower if DEC had made an earlier decision about early retirement and if the dates for retirement were earlier as well.

Q. HOW DOES THE 2017 ALLEN PRESENTATION AFFECT YOUR VIEW OF THE PRUDENCE OF COSTS AT OTHER DEC COAL PLANTS?

A. [redacted]

[67] See DEC response to Tech Customers Data Request 7-2(i) (attached as Exhibit KGS 19) that states in part, [redacted]

Q. HOW MUCH IN CAPITAL EXPENDITURES HAS DEC SPENT ON ITS COAL-FIRED POWER PLANTS SINCE ITS PRIOR RATE CASE?

A. DEC made $944 million in capital expenditures related to its coal power plants during the 2017 and 2018 calendar years. Of that amount, $241 million was approved by the Commission as post-test year additions to plant, leaving net expenditures not yet approved by this Commission of $703 million. In particular, I note there are expenditures not yet approved by this Commission of $31 million for Cliffside Unit 5, $119 million for Cliffside expenditures common to Units 5 & 6, and $72 million for the Allen Plant (no breakdown by unit available).[68]

[redacted]

These are not insignificant amounts of money. The higher the amount, the more scrutiny for potential imprudence is justified. These costs are broken down by unit and plant in Table 5 and Table 6, respectively, below.

[68] *See* Table 5 below.

[69] *See* Table 6 below.

Table 5: Capital Expenditure at Coal-Fired Generation Units[70]

Coal-Firing Generating Units	2017-2018 CapEx	Post-Test Addition to Plant	Not-Yet-Approved Expenses
Allen	105,224,223	32,885,765	72,338,457
Belews Creek	306,482,873	107,231,868	199,251,004
Cliffside Unit 5	66,610,657	35,278,354	31,332,302
Cliffside Common 5 & 6	131,180,758	12,411,443	118,769,315
Cliffside Unit 6	53,444,900	11,610,752	41,834,148
Marshall	281,087,954	41,986,522	239,101,432
Total	944,031,365	241,404,706	702,626,659

Table 6: 2019 Capital Expenditure Estimate[71]

[redacted]

[redacted]

[70] Source: DEC's response to Tech Customers Data Request 9-4, specifically the spreadsheet "2019 DEC NC TC 9-4a&b" (attached as Exhibit KGS 20).

[71] DEC's response to Tech Customers Data Request 3-27(f), specifically the spreadsheet "CONFIDENTIAL 2019 DEC NC Tech Customer DR3-27f" (attached as Exhibit KGS 21). Table 6 adds up environmental and non-environmental capital expenditures from that exhibit.

Q. DOES MUCH OF DEC'S RECENT COAL-RELATED INVESTMENT INVOLVE COMPLIANCE WITH ENVIRONMENTAL REGULATIONS GOVERNING THE TREATMENT OF COAL ASH?

A. Yes. DEC has made substantial investments in response to regulations that govern the handling and storage of coal ash. These investments were necessary to respond to environmental mandates that would have needed to be made irrespective of whether the units continue to operate. I do not challenge the need to comply with environmental regulations, yet I believe it is worthwhile for the Commission to investigate whether early retirement of the units could have reduced the amounts of these investments—*e.g.*, with an earlier decision to retire the units, an earlier retirement date, or even under the current retirement plan. [redacted]

Q. PLEASE SUMMARIZE THE POTENTIAL FOR DEC'S INVESTMENTS IN ITS COAL-FIRED POWER PLANTS SINCE ITS LAST RATE CASE TO BE FOUND IMPRUDENT.

A. [redacted]

[72] *See* Footnote 64 above.

[redacted] I recommend that the Commission put the onus on DEC to affirmatively establish the prudence of DEC's expenditures on Cliffside Unit 5 and Allen Units 4 and 5.

Potentially, the above-described issues and concerns about Cliffside Unit 5 and Allen Units 4 and 5 may apply to the other DEC coal units. The Commission may wish to add other units to the list of those for which DEC must make an affirmative case demonstrating the prudence of its investments in them since the last rate case—particularly Marshall Units 1 & 2, the retirement of which DEC has also decided to accelerate.

Q. WHAT ALTERNATIVES DOES DEC HAVE, IN THE CASE OF EARLY RETIRING OF COAL POWER PLANTS?

A. While I have not performed a detailed "IRP"-type analysis, I am aware that DEC has several options available to replace energy and capacity when a unit retires, in addition to the possibility of new-build capacity.

73 [redacted]

- To the extent that DEC has surplus capacity,[74] DEC may not need to replace a unit at all, or at least not right away.
- With the relative surplus of capacity in the region in which DEC operates,[75] DEC may have relatively cheap replacement options in terms of short or long-term purchases under contracts or by purchasing existing power plants.[76]
- Utility-scale renewables have rapidly developed in the region and in North Carolina specifically, particularly with solar, often at competitive prices on a $/MWh basis.
- The combined effects of a relative surplus of capacity, lower natural gas prices, and the increased penetration of renewables have also led to lower energy prices in the market (either alone, or in conjunction with capacity).
- Energy efficiency and demand response can reduce the need for new capacity.

VII. The Return of Tax Act Benefits to Customers Should Be Expeditious

Q. WHAT IS EDIT?

A. EDIT stands for Excess Deferred Income Taxes. The Tax Cuts and Jobs Act of 2017 ("Tax Act") lowered the statutory federal tax rate from 35 to 21 percent and lowered the amount of Accumulated Deferred Income Taxes ("ADIT") that utilities need to keep on the books. EDIT is the difference between the ADIT that had been collected from customers based on a 35 percent tax rate and the ADIT necessary to pay future utility taxes at a 21 percent tax rate. Given the reduction in the applicable tax rate, DEC has over-collected taxes from customers, thereby creating excess

74 See Footnote 60 above.

75 See Footnote 61 above.

76 I reviewed regional power plant transactions over the last decade and found multiple sales at reasonable prices – particularly compared to the amount of DEC's expenditure on its coal plants in recent years.

deferred income taxes or EDIT. The Tax Act reduced the future tax liability of utilities and the overcollections now need to be returned to customers.

Q. WHAT IS THE EDIT FLOWBACK PERIOD?

A. The EDIT flowback period is the time period over which DEC returns EDIT to customers (*e.g.*, 5 years).

Q. PLEASE DESCRIBE THE TENSION BETWEEN DEC AND ITS CUSTOMERS REGARDING EDIT FLOWBACK.

A. Its filings in the past and current rate case suggest that DEC prefers a relatively long flowback period for those portions of EDIT where the Tax Act does not specify a flowback period. In contrast, the Tech Customers – and presumably other DEC customers – prefer to receive the EDIT flowback relative quickly.

Q. PLEASE DESCRIBE THE DIFFERENT CATEGORIES OF EDIT?

A. DEC witnesses Ms. McManeus identifies five categories in DEC's proposed EDIT rider:[77]

a. Protected EDIT;
b. Unprotected PP&E EDIT;
c. Unprotected Non-PP&E EDIT;
d. NC EDIT; and
e. Deferred Revenue.

The Tax Act prescribes the manner with which regulated utilities return Federal "protected" EDIT to customers. The Commission decides how to return the other "unprotected" EDIT to customers.

[77] *See* McManeus Direct Testimony, Exhibit 4, Page 1.

Q. IN YOUR VIEW, HOW QUICKLY SHOULD DEC FLOW THE EDIT BACK TO CUSTOMERS?

A. Table 7 below summarizes DEC's EDIT position by category, DEC's proposed flowback period, and my recommendation.

Table 7: EDIT Summary and NERA Position

Federal or State	EDIT Type	Category	Amount[78]	DEC Proposed Flowback	Strunk Recommendation
Federal	Protected	PP&E	$1,193M	39 years	Mandated
Federal	**Unprotected**	**PP&E**	**$783M**	**20 years**	**5 years max**
Federal	Unprotected	Non-PP&E	$199M	5 years	Acceptable
Federal	Unprotected	Def. rev.	$34M	5 years	Acceptable
NC	Unprotected	All		5 years	Acceptable

DEC's proposed 20-year flowback of the Federal Unprotected PP&E EDIT extends too long into the future. Shortening of the flowback period is justified on two grounds: first, it is supported by regulatory precedent in other jurisdictions; and second, it can help to mitigate DEC's proposed rate increases.

Q. PLEASE DESCRIBE THE REGULATORY PRECEDENT TO WHICH YOU REFER.

A. Since the Tax Act, commissions across the U.S. have had to direct their utilities on the flowback periods for unprotected EDIT. SNL Financial, a utility sector data provider, conducts research and aggregates news articles covering the latest actions by state commissions. A survey of news articles during the past twelve months that pertain to unprotected EDIT produces the results displayed in Table 8 below. For

[78] *Ibid.*

a more detailed version of the same table containing sources and article quotations, please see Exhibit KGS 22.

Table 8: Unprotected EDIT Flowback Survey

Article Date	State	Company	Flowback	Type	Policy Status
Jan 31, 2020	TX	CenterPoint Energy Inc.	30-36 months	Elec	Settlement
Jan 27, 2020	VA	Roanoke Gas Co.	5 years	Gas	Order
Jan 16, 2020	NY	Consolidated Edison Co.	5 years	Elec/Gas	Order
Jan 16, 2020	ME	Central Maine Power Co.	Rate hike offset	Elec	Co. proposal
Jan 16, 2020	MO	Empire District Electric Co.	3 years	Elec	Co. proposal
Jan 15, 2020	NY	New York State Electric & Gas Corp.	Elec 3 years; Gas 10 years	Elec/Gas	Co. proposal
Jan 15, 2020	NY	Rochester Gas and Electric Corp.	10 years	Elec/Gas	Co. proposal
Dec 27, 2019	NV	Sierra Pacific Power Co.	6 years	Elec	Settlement
Dec 23, 2019	VA	Washington Gas Light Co.	10 years	Gas	Co. proposal
Dec 20, 2019	GA	Atlanta Gas Light Co.	Rate hike offset	Gas	Order
Dec 16, 2019	FERC	Oklahoma Gas & Electric	5 years	Elec/Gas	Order
Dec 11, 2019	MS	Mississippi Power Co.	6 years	Elec	Co. proposal
Dec 5, 2019	IN	Northern Indiana Public Service Co.	11 years	Elec	Order
Dec 4, 2019	WA	Puget Sound Energy Inc.	4 years	Gas	Co. proposal
Nov 22, 2019	WA	Avista Corp.	Accelerated depreciation offset	Elec	Settlement
Nov 19, 2019	MT	NorthWestern Corp.	5 years	Elec	Order
Nov 18, 2019	NC	Piedmont Natural Gas Co.	5 years	Gas	Order
Nov 7, 2019	NY	Brooklyn Union Gas Co.	10-44 years	Gas	Co. proposal
Nov 7, 2019	NY	KeySpan Gas East Corp.	10-14 years	Gas	Co. proposal
Sep 5, 2019	WI	Northern States Power Co. – Wisconsin	Rate hike offset and bill credits	Elec	Order
Aug 21, 2019	MO	Union Electric Co.	10 years	Elec	Co. proposal
Aug 9, 2019	TX	Southwestern Public Service Co.	5 years	Elec	Order
Aug 5, 2019	TX	AEP Texas Inc.	5 years	Elec	Order
Jul 15, 2019	LA	Cleco Power LLC	6 years	Elec	Co. proposal
Jul 9, 2019	VA	Columbia Gas of Virginia Inc.	5 years	Gas	Order
Jun 25, 2019	AZ	Southwest Gas Corp.	3 years	Gas	Co. proposal
Jun 5, 2019	NH	Public Service Co. of New Hampshire	5 years	Elec	Order
May 14, 2019	NJ	Rockland Electric Co.	3 years	Elec	Commission requirement
Apr 3, 2019	HI	Maui Electric Co. Ltd.	15 years	Elec	Settlement
Mar 14, 2019	NJ	Atlantic City Electric Co.	10 years	Elec	Co. proposal

Article Date	State	Company	Flowback	Type	Policy Status
Mar 14, 2019	NY	Orange and Rockland Utilities Inc.	15 years	Elec/Gas	Order
Mar 6, 2019	WV	Appalachian Power Co.	2 years	Elec	Order
Mar 6, 2019	WV	Wheeling Power Co.	2 years	Elec	Order
Feb 5, 2019	KS	ONE Gas Inc.	5 years	Gas	Order

Source: SNL Financial.

In light of the above evidence, I regard DEC's proposed 20-year flowback period for Unprotected PP&E EDIT as excessively long.

Q. HOW CAN EDIT MITIGATE RATE INCREASES?

A. In DEC's last rate case, the Commission allowed certain cost increases but approved an overall decrease in revenue for DEC. It was the return of EDIT that took DEC from a revenue increase to a revenue decrease. That tool remains available to the Commission as DEC continues to seek approval of revenue increases.

Q. WHAT DO YOU PROPOSE FOR A FLOWBACK PERIOD FOR UNPROTECTED EDIT?

A. The Commission has discretion on setting the amortization period for the unprotected EDIT. I propose that the Commission adopt a flowback period no longer than 5 years for all DEC unprotected EDIT (both PP&E and non-PP&E). A 5-year flowback period returns over-collected taxes to customers in a timely manner and aligns with policy in other states.

Q. WHAT WAS THE TECH CUSTOMERS' POSITION ON EDIT IN DEC'S PRIOR RATE CASE?

A. In the prior rate case, counsel for the Tech Customers asked NERA to analyze certain matters relating to the effects of the Tax Act on DEC. Specifically, Dr.

Sharon Brown-Hruska and I evaluated the reasonableness of DEC's contention that a $200 million annual increase in the revenue requirement was required to maintain its credit quality following the flowback of EDIT.[79] DEC requested the $200 million in connection with AMR meters, coal-fired plants, or coal ash clean-up on an accelerated basis.[80]

Dr. Brown-Hruska and I reverse-engineered the mathematical assumptions underpinning Mr. DeMay's testimony, then recomputed DEC's projected FFO/Debt ratio without the $200 million annual revenue requirement increase. In other words, without making any assumptions, I simply took DEC's own forecast and adjusted it to remove the $200 million increase. The result was that DEC's FFO/Debt projection continued to fall squarely within the zone identified by S&P and Moody's as necessary to maintain the current rating. Thus, I recommended that the Commission reject the request to offset customer savings with a $200 million revenue requirement increase.

Q. HOW DOES DEC'S POSITION ON EDIT IN THE PRIOR RATE CASE PERTAIN TO THE CURRENT RATE CASE?

A. In the prior rate case, DEC sought to justify its longer flowback period on financial grounds. My analysis demonstrated that DEC's justifications were without merit. I believe this experience serves as further evidence to question DEC's claims regarding the need to stretch out the EDIT flowback period in this case and should

[79] Docket No. E-7, Sub 1146, Dr. Sharon Brown-Hruska and Kurt G. Strunk Supplemental Testimony (Mar. 20, 2018).

[80] Supplemental Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. M-100, Sub 148.

encourage the Commission to return the Unprotected PP&E EDIT (*i.e.*, over-collected taxes) to customers over a shorter flowback period than proposed by DEC.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MR. CRYSTAL: Chair Mitchell, Howard Crystal for the Center for Biological Diversity and Appalachian Voices.

CHAIR MITCHELL: All right. Mr. Crystal, you may proceed.

MR. CRYSTAL: Similar motion. I'd like to move the admission of the testimony of our excused witness, Dr. Shaye Wolf. Dr. Wolfe's testimony was filed February 18th, 2020, consisting of 36 pages and one exhibit, SW-1. I move the testimony be entered into the record in the proceeding and copied into the record as if given orally from the stand at the appropriate time.

CHAIR MITCHELL: Hearing no objection, your motion is allowed.

(Whereupon, the prefiled testimony of Shaye Wolf, Ph.D., stricken by Commission order dated 3/3/2020, was copied into the record as if given orally from the stand.)

(Exhibit SW-1 was admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. DOCKET NO. E-7, SUB 1214

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Carolinas, LLC	)	**SHAYE WOLF, Ph.D. FOR**
For Adjustment of Rates And Charges	)	**CENTER FOR BIOLOGICAL**
Applicable to Electric Service	)	**DIVERSITY AND**
in North Carolina	)	**APPALACHIAN VOICES**

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I. PROFESSIONAL QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A: My name is Shaye Wolf, Ph.D. I am the Climate Science Director at the Climate Law Institute, a program of the Center for Biological Diversity. My business address is the Center for Biological Diversity, 1212 Broadway, Suite 800, Oakland, CA 94612.

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND

A: I hold a Bachelor of Science degree in Biology from Yale University (1995), a Masters of Science Degree in Ocean Sciences from the University of California, Santa Cruz (2002), and a Ph.D. in Ecology and Evolutionary Biology, also from the University of California, Santa Cruz (2007).

I have been the Climate Science Director at CLI for almost ten years. Among other activities, CLI engages in ambitious, protective and science-based campaigns and litigation to keep fossil fuels in the ground and slash greenhouse pollution while also promoting the just transition from a fossil fuel economy to 100 percent clean, renewable energy. In the role as Climate Science Director, I regularly review scientific journal articles and government reports related to climate change and the key steps necessary to combat it – *i.e.,* the rapid transition from a fossil fuel economy to one driven by clean energy. I also communicate with scientists and the public about climate change; attend scientific conferences on climate change; author technical comments, reports, and other publications on the harms of climate change to human communities, species, and ecosystems; and contribute to climate change mitigation and adaptation plans. A full list of my publications is attached (*see* SW-1, attached), and they include, for example:

- American Geophysical Union, Primary Session Convener and Chair: "Aligning U.S. Energy Policy with a 1.5°C Climate Limit: How to Design and Manage a Fossil Fuel Extraction Phase-out and an Equitable Energy Transition," December 2019
- Whitlock, C., D.A. DellaSala, S. Wolf, and C.T. Hanson, Climate Change: Uncertainties, Shifting Baselines, and Fire Management. Pp. 265-289 in The Ecological Importance of Mixed Severity Fires: Nature's Phoenix, D.A. DellaSala and C.T. Hanson, eds. Elsevier, Amsterdam, Netherlands (2015)
- Not Just a Number: Achieving a CO_2 Concentration of 350 ppm or Less to Avoid Catastrophic Climate Impacts, Center for Biological Diversity and 350.org (2010).

I am also an active member of several professional organizations, including US Climate Action Network and the American Geophysical Union, and have participated in several fellowships, including the Switzer Environmental Fellowship (2000). Prior to my role in CLI, I have served as a research biologist and technician at several institutions, including several federal agencies, universities, and non-profit organizations.

Q: HAVE YOU TESTIFIED PREVIOUSLY IN UTILITY PROCEEDINGS?

A: No, I have not previously provided testimony in a utility proceeding.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of the Center for Biological Diversity and Appalachian Voices.

Q. WHAT MATERIALS DID YOU REVIEW IN PREPARING THIS TESTIMONY?

A. I have reviewed Governor Cooper's Executive Order ("EO") 80, the North Carolina Clean Energy Plan, and the recent slides prepared by the North Carolina Climate Change Research Council. I have also reviewed the various governmental, scientific, and other reports I will discuss in my testimony.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to highlight the inadequacies in Duke Energy Carolina's ("DEC") Rate Application, particularly as it relates to Intervenors' Witness Greer Ryan's testimony concerning DEC's continued reliance on fossil fuels and proposed Grid Improvement Plan, as well as storm damage costs. ~~I will detail the rapid transition away from dirty fossil fuel energy sources that climate science demands, and that is critical to implementing EO 80 and North Carolina's Clean Energy Plan, all of which are intended to address the climate emergency and ultimately serve the public interest at issue in this rate proceeding. I will also discuss the ever-increasing costs to North Carolinians of failing to act on the climate emergency, in light of the overwhelming evidence~~

~~concerning current and future climate impacts in the region.~~

~~Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS~~

~~The testimony that follows will:~~

- ~~detail the rapid transition to clean energy sources that are absolutely required to meet the goals of EO 80, the North Carolina Clean Energy Plan, and climate science;~~
- ~~detail the harms to North Carolinians that will come from failing to take the steps necessary to address the worst impacts of climate change.~~

~~In light of my testimony below, I recommend that the Commission take into account the impacts of this rate-making proceeding on the climate emergency, and, as detailed in the testimony of Greer Ryan, specifically consider whether the Application is consistent with the policy demands of EO 80, the Clean Energy Plan, and ultimately climate science. Other recommendations in light of this testimony are also contained in the Intervenor Testimony of Greer Ryan.~~

~~II. DEC'S RATE APPLICATION FAILS TO MEET THE DEMANDS OF EXECUTIVE ORDER 80, THE NORTH CAROLINA CLEAN ENERGY PLAN, AND CLIMATE SCIENCE~~

~~Q: PLEASE DESCRIBE NORTH CAROLINA'S STATE-WIDE COMMITMENT TO THE RENEWABLE ENERGY TRANSITION AND ITS BASIS.~~

A: ~~Governor Cooper's Executive Order ("EO") 80, issued in October, 2018, calls for a rapid reduction in greenhouse gas emissions across North Carolina, including a seven-year deadline (2025) to reduce statewide greenhouse gas emissions to 40% below 2005 levels.[1]~~

~~The EO also directed the North Carolina Department of Environmental Protection to prepare a North Carolina Clean Energy Plan "that fosters and encourages the utilization of clean energy resources, including energy efficiency, solar, wind, energy storage, and other innovative technologies in the public and private sectors, and the integration of those resources to facilitate the development of a modem and resilient electric grid."~~

~~In issuing the EO Governor Cooper recognized the urgent need for these actions to address the climate crisis, which, he explained, is causing both "more frequent and intense hurricanes, flooding, extreme temperatures, [and] droughts," while also posing "significant health risks to North Carolinians, including waterborne disease outbreaks, compromised drinking water, increases in disease-spreading organisms, and exposure to air pollution." I will discuss these and other climate change concerns in more detail later in my testimony.~~

~~[1] The EO is available at https://files.nc.gov/ncdeq/climate-change/EO80--NC-s-Commitment-to-Address-Climate-Change---Transition-to-a-Clean-Energy-Economy.pdf~~.

Q: ~~PLEASE DESCRIBE THE CLEAN ENERGY COMMITMENTS CONTAINED IN THE NORTH CAROLINA CLEAN ENERGY PLAN AS THEY RELATE TO ELECTRICITY GENERATION.~~

~~A: In October, 2019, the North Carolina Department of Environmental Quality issued the North Carolina Clean Energy Plan, as directed by Governor Cooper in EO 80.[2] The Plan identified the following three clean energy objectives for North Carolina:~~

- ~~"Reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050";~~
- ~~"Foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes;" and~~
- ~~"Accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state."~~

~~*Id.* at 12.~~

~~The Plan also identified three concrete steps that are vital to achieving these goals:~~

1. ~~Developing "carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options";~~

~~2 The Plan is available at https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.~~

~~2.~~ ~~Developing and implementing "policies and tools such as performance-based mechanisms, multiyear rate planning, and revenue decoupling, that better align utility incentives with public interest, grid needs, and state policy"; and~~

~~3.~~ ~~"Moderniz[ing] the grid to support clean energy resource adoption, resilience, and other public interest outcomes."~~

~~*Id.*~~

~~The Plan then identified specific actions to accomplish these steps, including the following actions directly related to this proceeding:~~

Most significantly, recognizing the importance of grid modernization to meeting the State's greenhouse gas emission reduction goals, the Plan explains that, "the grid needs to be updated and improved in order to accommodate DER [Distributed Energy Resources] growth and new load from electrification of end-use . . . ." *Id.* at 83. To meet this goal, the Plan provides that this Commission, "when evaluating proposals for grid modernization," should "consider whether the following outcomes are supported":

- "Demonstrated net benefits for all proposed investments, including presentation of all costs and benefits used in utility analyses";
- "Enhanced transparency of regionally appropriate DERs, grid needs and opportunities for DERs to Interconnect";
- "Increased customer access to their usage data and sources of energy";

- "Facilitation of greater utilization of storage, demand-side resources, grid operation/management devices, and the bi-directional flow of power;"
- "Measurement of performance to ensure anticipated benefits are delivered and accounted for"; and
- "Increased deployment of clean energy."

Id. at 14 and 83.

More specifically, the Plan refers to the Grid Improvement Plan submitted with DEC's Rate Application, and, noting that the Commission "will be the entity responsible for approving the Plan," states that the Commission should "use [these] recommended outcomes listed above to guide evaluation of Duke's" Grid Improvement Plan, in order "to maximize the potential benefits of grid modernization investments and to protect against potential utility capital bias." *Id.* at 83-4.

In addition, the Plan identifies a series of additional issues that DEC should be taking into account in its Rate Application. Of significance here, the Plan calls for:

- "[D]ifferent DER penetration scenarios or a more granular system assessment (e.g., at the circuit level) [to] help identify which new investments are necessary to maintain reliability" *Id.* at 85.
- "[I]mproving the linkage between transmission, resource, and grid modernization planning [to] better identify solutions to transmission

system constraints that could be prohibiting greater levels of renewable generation on the system in the eastern part of the state." *Id.*

- "[M]aking sure utilities establish performance metrics, targets and accompanying timelines" to be held accountable. *Id.*
- "[V]oluntary on-bill pay as you save tariff" to encourage energy efficiency investments. *Id.* at 96.
- "[R]ate design pilots that encourage customers to shift their usage and utilize technologies like storage to help reduce peak demand and increase utilization of clean energy." *Id.* at 134.
- "[P]ilots designed to test innovative rate design that encourages off peak charging and EV [electric vehicle] adoption." *Id.* at 139.
- "[E]xpanded clean energy resources" that will be necessary to achieve the Plan's objective for reducing electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030. *Id.* at 60.

As discussed in the testimony of Greer Ryan, DEC's Rate Application fails to address these important elements, including the Plan's specific reference to the Grid Improvement Plan submitted in this proceeding.[3]

~~**Q: PLEASE PROVIDE A BROADER OVERVIEW OF THE CLEAN ENERGY TRANSITION NECESSARY TO ADDRESS THE CLIMATE**~~

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[3] Testimony of Greer Ryan at 5-21.

~~**CHANGE THREATS IDENTIFIED IN EO 80 AND NORTH CAROLINA'S CLEAN ENERGY PLAN, AND YOUR CONCERNS REGARDING WHETHER DEC'S APPLICATION IS CONSISTENT WITH THESE URGENT NEED FOR THIS TRANSITION.**~~

~~A: Both EO 80 and the Clean Energy Plan recognize the urgent threats to North Carolina posed by climate change, which I will discuss further below. See Section IV, infra. To meet the mandate to "[r]educe electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050," the Commission must require that all North Carolina utilities take concrete and immediate steps to transition North Carolina electricity away from fossil fuels.~~

~~Numerous reports have detailed the steps that must be urgently undertaken in the electricity sector to meet these goals. For example, a 2015 study from a team headed by Dr. Mark Jacobson explains the steps needed to attain 80% of our energy from greenhouse gas free sources by 2030, and 100% by 2050.[4] Under that roadmap, the United States needs to be approaching 50% clean energy as soon as 2025. *Id.* at 2113.[5]~~

[4] ~~*See, e.g.*, Jacobson et al., 100% Clean and Renewable Wind, Water, and Sunlight All-Sector Energy Roadmaps for the 50 United States, 8 Energy and Environmental Science 2093 (2015)~~

[5] ~~*See also, e.g.* Creutzig, Felix et al., The underestimated potential of solar energy to mitigate climate change, 2 Nature Energy 17140 (2017); Jacobson et al., 100% clean and renewable wind, water, and sunlight (WWS) all-sector energy roadmaps for 139 countries of~~

~~As detailed in Intervenors' Greer Ryan's Testimony, DEC's Application entirely fails to demonstrate that DEC is on target to meet any of these goals.~~[6] ~~DEC intends to still be relying on 50% fossil fuels by 2034, well beyond the 2025 target outlined by Jacobson.~~[7] ~~Moreover, it is simply not consistent with EO 80, the Clean Energy Plan or climate science for more than 40% of DEC's capacity additions in coming years be from fossil fuels. Rather, DEC must make a much faster transition to clean energy sources.~~

~~III. DUKE ENERGY'S FOSSIL FUEL GENERATION EXACERBATES THE CLIMATE CRISIS.~~

~~Q: PLEASE DISCUSS THE CONNECTION BETWEEN FOSSIL FUEL GENERATION AND CLIMATE CHANGE.~~

~~A: An overwhelming body of scientific evidence has established that greenhouse gas emissions from fossil fuels are driving climate change. In 2017, the Fourth National Climate Assessment – a scientific synthesis prepared by hundreds of scientific experts and reviewed by the National Academy of Sciences and federal agencies – concluded that "fossil fuel combustion accounts for approximately~~

~~the world, 1 Joule 108 (2017); Bogdanov, Dmitri et al., Radical transformation pathway towards sustainable electricity via evolutionary steps, Nature Communications (2019).~~

~~6 Testimony of Greer Ryan at 5-21.~~

~~7 *Id.* at 6.~~

~~85 percent of total U.S. greenhouse gas emissions,"~~[8] ~~which is "driving an increase in global surface temperatures and other widespread changes in Earth's climate that are unprecedented in the history of modern civilization."~~[9] ~~The Intergovernmental Panel on Climate Change (IPCC), the international scientific body for the assessment of climate change, stated in its Fifth Assessment Report that "[c]arbon dioxide concentrations have increased by 40% since pre-industrial times, primarily from fossil fuel emissions."~~[10]

~~In 2018, the IPCC issued a *Special Report on Global Warming of 1.5°C*, which estimated the remaining global carbon budget—the cumulative amount of carbon dioxide that can be emitted—for maintaining a likely chance of meeting the 1.5°C climate target under the Paris Agreement, providing clear benchmarks for global and U.S. climate action. The global carbon budget for a 66 percent probability of limiting warming to 1.5°C is approximately 420 GtCO~~$_2$ ~~to 570 GtCO~~$_2$ ~~from January 2018 onwards, depending on the temperature dataset used.~~[11] ~~At the current global emissions rate of 42 GtCO~~$_2$ ~~per year, this carbon~~

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8 ~~U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 60.~~

9 ~~*Id.* at 39.~~

10 ~~Intergovernmental Panel on Climate Change, Summary for Policymakers, Climate Change 2013: The Physical Science Basis, Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F. et al (eds.)] at 9.~~

11 ~~IPCC, 2018: Summary for Policymakers. In: Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and~~

~~budget would be expended in just 10 to 14 years, underscoring the need for immediate, transformative actions to transition from fossil fuel use to clean energy.~~

~~Given the limited remaining global carbon budget, the IPCC report concluded that 1.5°C pathways require global net anthropogenic CO_2 emissions to decline by about 45 percent from 2010 levels by 2030, and to reach net zero around 2050.[12] However, wealthier nations such as the United States have a responsibility to make much larger emissions reductions, due to their dominant role in driving climate change and its harms, combined with their greater financial resources and technical capabilities to implement emissions cuts.~~

~~The IPCC report emphasized that pathways consistent with staying within the carbon budget for limiting warming to 1.5°C require "rapid and far-reaching transitions" across all sectors including electricity generation.[13] Importantly, a robust feature of 1.5°C-consistent pathways is that the power sector must be significantly clean by 2030 and achieve a "virtually full decarbonisation" around mid-century.[14] In the IPCC's socially and~~

~~related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V. et al. (eds.)] at 12.~~

~~12 *Id.* at 12.~~

~~13 *Id.* at 15.~~

~~14 Rogelj, Joeri, et al., 2018: Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development. In: Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse~~

~~environmentally just pathways consistent with a 1.5°C target, renewables reach a 60 percent share in electricity by 2030.[15]~~

~~At the national level, research on the United States' carbon budget establishes that the U.S. must make urgent, aggressive cuts in domestic fossil fuel emissions to avoid the worst dangers of climate change. The U.S. is the world's largest historic emitter of greenhouse gas pollution, responsible for 25 percent of cumulative global CO_2 emissions since 1870, and is currently the world's second highest emitter on an annual and per capita basis.[16] Scientific studies have estimated the remaining U.S. carbon budget consistent with the 1.5°C Paris Agreement target is approximately 25 gigatons (Gt) CO_2eq to 57 GtCO_2eq on average,[17] depending on the equity principles used to apportion the~~

~~gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., et al. (eds.)] (2018) at 112.~~

~~15 IPCC, 2018: Summary for Policymakers. In: Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V. et al. (eds.)] at 15.~~

~~16 LeQuéré, Corinne et al., Global carbon budget 2018, 10 Earth System Science Data 2141 (2018) at Figure 5, 2167; Global Carbon Project, Global Carbon Budget 2018 (published on 5 December 2018) https://www.globalcarbonproject.org/carbonbudget/18/files/GCP_CarbonBudget_2018.pdf at 19 (Historical cumulative fossil CO_2 emissions by country).~~

~~17 Robiou du Pont, Yann et al., Equitable mitigation to achieve the Paris Agreement goals, 7 Nature Climate Change 38 (2017), and Supplemental Tables 1 and 2. Quantities measured in GtCO_2eq include the mass emissions from CO_2 as well as the other well-mixed greenhouse gases (CO_2,methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and SF_6) converted into CO_2-equivalent values, while quantities measured in GtCO_2 refer to mass emissions of just CO_2 itself.~~

~~global budget across countries.[18] As the U.S. emits around 6 $GtCO_2eq$ each year, the remaining U.S. carbon budget compatible with the Paris climate targets is extremely small and is rapidly being expended, highlighting the urgent need for the U.S. to transition from fossil fuels to clean energy.~~

~~In the meantime, the global atmospheric CO_2 concentration reached a record high in May 2019 at 415 parts per million (ppm), a level not seen for millions of years.[19] The last time CO_2 in Earth's atmosphere was at 400 ppm, global mean surface temperatures were 2 to 3°C warmer and the Greenland and West Antarctic ice sheets melted, leading to sea levels that were 10 to 20 meters higher than today.[20] The current atmospheric CO_2 concentration is nearly one and half times larger than the pre-industrial level of 280 ppm, and much greater~~

~~18 Robiou du Pont et al. (2017) averaged across IPCC sharing principles to estimate the U.S. carbon budget from 2010 to 2100 for a 50 percent chance of returning global average temperature rise to 1.5°C by 2100, based on a cost-optimal model. The study estimated the U.S. carbon budget consistent with a 1.5°C target at 25 $GtCO_2eq$ by averaging across four equity principles: capability (83 $GtCO_2eq$), equal per capita (118 $GtCO_2eq$), greenhouse development rights (-69 $GtCO_2eq$), and equal cumulative per capita (-32 $GtCO_2eq$). The study estimated the U.S. budget at 57 $GtCO_2eq$ when averaging across five sharing principles, adding the constant emissions ratio (186 $GtCO_2eq$) to the four above-mentioned principles. However, the constant emissions ratio, which maintains current emissions ratios, is not considered to be an equitable sharing principle because it is a grandfathering approach that "privileges today's high-emitting countries when allocating future emission entitlements."~~

~~19 National Oceanic and Atmospheric Administration, Carbon dioxide levels in atmosphere reached record high in May (June 4, 2019), https://www.noaa.gov/news/carbon-dioxide-levels-in-atmosphere-hit-record-high-in-may.~~

~~20 LeQuéré, Corinne et al., Global carbon budget 2018, 10 Earth Syst. Sci. Data 2141 (2018); World Meteorological Organization, WMO Greenhouse Gas Bulletin, No. 13, October 30, 2017 at 5.~~

~~than levels during the past 800,000.[21] The atmospheric concentrations of methane (CH_4) and nitrous oxide (N_2O), two other potent greenhouse gases, are 257 percent and 122 percent of their pre-industrial levels.[22] Global carbon emissions over the past 15 to 20 years have tracked the highest emission scenario used in IPCC climate projections, the RCP8.5 scenario[23] which is projected to lead to devastating impacts.[24]~~

~~Q: WHAT IS DUKE ENERGY'S CONTRIBUTION TO U.S. GREENHOUSE GAS EMISSIONS?~~

~~A: The electricity sector, in tandem with the transportation sector, is the leading source of U.S. greenhouse gas emissions, making up 28% of total greenhouse gas emissions in 2017.[25] DEC's parent company, Duke Energy, is the largest~~

~~[21] Intergovernmental Panel on Climate Change, Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (2014) at 4, 44; World Meteorological Organization, WMO Greenhouse Gas Bulletin, No. 13, October 30, 2017 at 1, 4.~~

~~[22] World Meteorological Organization, WMO Greenhouse Gas Bulletin, No. 13, October 30, 2017 at 2.~~

~~[23] U.S. Global Change Research Program, Climate Science Special Report: Fourth National Climate Assessment, Volume I x(2017), https://science2017.globalchange.gov/ at 31, 133, 134, and 152 (e.g. "The observed increase in global carbon emissions over the past 15–20 years has been consistent with higher scenarios (e.g., RCP8.5) (*very high confidence*)" at 31.)~~

~~[24] Intergovernmental Panel on Climate Change, Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (2014) at Figure 2.1.~~

~~[25] U.S. Environmental Protection Agency, Sources of Greenhouse Gas Emissions (2019), https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.~~

~~electricity provider in the country and one of the largest in the world.~~[26] ~~In terms of greenhouse gas emissions, Duke Energy ranks as the number one producer of~~ ~~CO_2 and NOx emissions of all power providers in the country, emitting 104.6 million short tons of CO_2 emissions and 61.02 thousand short tons of NOx pollution in 2017 alone.~~[27] ~~In short, Duke Energy is a prominent contributor to the country's greenhouse gas emissions, and DEC, as part of the Duke Energy conglomerate, is a major contributor to total emissions.~~

~~IV. THE CLIMATE CRISIS THREATENS NORTH CAROLINA.~~

~~Q: WHAT KINDS OF THREATS DOES CLIMATE CHANGE POSE TO NORTH CAROLINA?~~

~~A: Climate change poses significant threats to people, species, and the environment in North Carolina. Last month the North Carolina Climate Change Advisory Council shared a presentation concerning the state of the climate crisis in the state.~~[28] ~~The Council is anticipated to shortly issue a final Climate Science Report, and this presentation summarized the Council's findings thus far.~~

~~26 Bank of America et al., Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States (June 2019), https://www.ceres.org/resources/reports/benchmarking-air-emissions-2019.~~

~~27 M.J. Bradley and Associates, Benchmarking Air Emissions of the 100 Largest Power Producers in the United States: CO2 Emissions and Emissions Rates – All-Source (2019), https://www.mjbradley.com/content/emissions-benchmarking-emissions-charts.~~

~~28 The presentation is available at https://files.nc.gov/ncdeq/climate-change/interagency-council/Jan-22-2020--Interagency-Climate-Council-presentation-rev.pdf.~~

~~The Advisory Council found that 2009-18 was the warmest period recorded in North Carolina, 2019 was the warmest year on record, and average temperatures have increased more than 1 degree Fahrenheit over the past century. *Id.* at 15.~~

~~Moreover, drawing from Volume II of the 2018 Fourth National Climate Assessment ("NCA"), *Impacts, Risks, and Adaptation in the United States* (Volume II),[29] the Advisory Council summarized that (a) greenhouse gas concentrations are "increasing rapidly," primarily caused by the "burning of fossil fuels"; (b) these increased concentrations are "likely causing much, if not all," of the earth's warming; and that it is (c) "virtually certain that global warming will continue, assuming GHG concentrations continue to increase." *Id.* at 8-10.~~

~~Given these conditions, the Advisory Council has concluded that, "Large changes in North Carolina's climate – much larger than at any time in the state's history – are very likely by the end of this century under both the lower and higher scenarios" of anticipated warming. *Id.* at 14.~~

~~These changes include the following:~~

- ~~Very likely that NC temperatures will increase substantially in all seasons;~~
- ~~Very likely increase in number of very warm nights;~~

~~[29] U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018).~~

- ~~Likely increase in number of hot days;~~
- ~~Likely decrease in number of cold days.~~

~~*Id.* at 17. The Council also found there will be an, "Upward trend in number of heavy rainfall events," *id.* at 19, and that it is "very likely that extreme precipitation frequency and intensity in North Carolina will increase." *Id.* at 20. This will also mean "increases in inland flooding." *Id.* at 29.~~

~~As regards sea level rise, the Council has concluded that it is "virtually certain that sea level will continue to rise along North Carolina coast," with high tide flooding becoming "nearly a daily occurrence by 2100," at which point sea levels may have risen more than three feet at Wilmington, and almost four feet at Duck. *Id.* at 22.~~

~~As for hurricanes, the Council found the, "[I]ntensity of strongest hurricanes likely to increase," and although the number of hurricanes is less certain, where hurricanes do occur in North Carolina, an increase in heavy precipitation is "very likely." *Id.* at 26~~

~~At the other extreme, the Council also found it, "Likely that severe droughts will be more intense," and a "likely increase in the frequency of climate conditions conducive to wildfires." *Id.* at 30.~~

~~Summing up its findings, the Council explained that we can anticipate "Large future climate changes for North Carolina if our current reliance on fossil fuels for energy continues," including (a) "Temperatures outside of historical envelope"; (b) "Disruptive sea level rise"; (c) "Increases in intensity and~~

~~frequency of extreme rainfall"; (d) "More intense hurricanes"; and (e) "Higher absolute humidity levels." *Id.* at 45.~~

~~These conclusions are consistent with Volume II of the Fourth National Climate Assessment, which focused on the regional effects of climate change, including a specific chapter on the Southeast, and found that "southern and midwestern populations are likely to suffer the largest losses from future climate changes in the United States," and that, "[a]lready poor regions, including those found in the Southeast, are expected to continue incurring greater losses than elsewhere in the United States."[30] The Report further detailed that in the Southeast "dangerous high temperatures, humidity, and new local diseases are expected to become more significant in the coming decades"; "[t]he number of extreme rainfall events is increasing"; and "[f]uture temperature increases are projected to pose challenges to human health." *Id.*~~

~~**Q: WHAT IS THE RELATIONSHIP BETWEEN CLIMATE CHANGE AND HURRICANES FLORENCE AND MICHAEL, WINTER STORM DIEGO, AND OTHER EXTRAODINARY EVENTS IN NORTH CAROLINA?**~~

~~[30] U.S. Global Climate Change Research Program, "Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II" (November 23, 2018) at 746.~~

~~A: Human-caused climate change, fueled by greenhouse gas emissions, is increasing the destructive power of hurricanes in three primary ways: boosting their (i) rainfall, (ii) intensity and (iii) storm surge. DEC's experience of three devastating storms in 2018—Hurricane Florence, Hurricane Michael, and Super Storm Diego—signify the real-life impacts of the climate crisis on DEC customers.~~

~~With regards to rainfall, climate change leads to warmer air, which holds more moisture and thereby causes heavier rainfall during hurricanes.[31] In 2018, Hurricane Florence caused extensive flooding damage in DEC territory. A study estimated that human-caused climate change increased the hurricane's overland rainfall amount by 5 percent, leading to unprecedented flooding.[32] The unprecedented rainfall of Florence was mirrored in the 2017 Hurricane Harvey, which dropped record amounts of rainfall, topping 60 inches over southeastern Texas,[33] unleashing catastrophic flooding that left 89 dead, displaced more than 30,000 people, and damaged or destroyed more than 200,000 homes and~~

~~[31] Emanuel, Kerry, Assessing the present and future probability of Hurricane Harvey's rainfall 2017, 114 PNAS 12681 (2017); Keellings, David & José J. Hernández Ayala, Extreme rainfall associated with Hurricane Maria over Puerto Rico and its connections to climate variability and change, 46 Geophysical Research Letters 2964 (2019).~~

~~[32] Reed, K.A. et al., Forecasted attribution of the human influence on Hurricane Florence, 6 Science Advances eaaw9253 (2020).~~

~~[33] NOAA and National Weather Service, National Hurricane Center Tropical Cyclone Report: Hurricane Harvey, National Hurricane Center (9 May 2018), https://www.nhc.noaa.gov/data/tcr/AL092017_Harvey.pdf.~~

~~businesses.[34] Studies estimate that global warming made Harvey's downpour 3.5 times more likely and at least 19 percent more intense.[35]~~

~~With regards to intensity, because hurricanes are fueled by heat, warming ocean temperatures are increasing the strength of Atlantic hurricanes[36] and allowing them to intensify more quickly.[37] Specifically, Hurricane Michael—a Category 5 storm at landfall—was amplified by unusually warm ocean waters that were up to up to 3.6°F (2°C) hotter than the historical average.[38] Hurricane Michael is not an exception in this era of the climate crisis; the country is experiencing the longest streak of Category 5 superstorms on~~

~~34 NOAA National Centers for Environmental Information (NCEI), U.S. Billion-Dollar Weather and Climate Disasters (2019). https://www.ncdc.noaa.gov/billions/.~~

~~35 Risser, Mark D. & Michael F. Wehner, Attributable human-induced changes in the likelihood and magnitude of the observed extreme precipitation during Hurricane Harvey, 44 Geophysical Research Letters 12,457 (2017).~~

~~36 Elsner, James B. et al., The increasing intensity of the strongest tropical cyclones, 455 Nature 92 (2008); Saunders, Mark A. & Adam S. Lea, Large contribution of sea surface warming to recent increase in Atlantic hurricane activity, 451 Nature 557 (2008); Holland, G. & C.L. Bruyère, Recent intense hurricane response to global climate change, 42 Climate Dynamics 617 (2014); Fraza, Erik & James B. Elsner, A climatological study of the effect of sea-surface temperature on North Atlantic hurricane intensification, 36 Physical Geography 395 (2015); U.S. Global Change Research Program, Climate Science Special Report: Fourth National Climate Assessment, Vol. I (2017), https://science2017.globalchange.gov/ at 257; U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 74.~~

~~37 Bhatia, Kieran T. et al., Recent increases in tropical cyclone intensification rates, 10 Nature Communication 635 (2019).~~

~~38 Climate Signals, Hurricane Michael October 2018 (last updated December 4, 2018), https://www.climatesignals.org/events/hurricane-michael-october-2018~~

~~record: Hurricane Dorian (2019) was the fifth Category 5 hurricane to form in the Atlantic in four years, following Michael (2018), Maria (2017), Irma (2017) and Matthew (2016). During 2017 and 2018 alone, five major hurricanes cost the United States at least 3,269 lost lives and $325 billion in damages.[39]~~

~~Further, with regards to storm surge, rising sea levels due to climate change are causing higher storm surge — the enormous walls of water pushed onto the coast by storms. Large storm surge events of the magnitude of Hurricane Katrina have already doubled in response to global warming, and are projected to increase in frequency by twofold to sevenfold for each degree Celsius of temperature rise.[40] At the same time, heavy seasonal snow and extreme snowstorms like Winter Storm Diego continue to occur with great frequency as the climate has changed. The frequency of extreme snowstorms in the eastern two-thirds of the contiguous United States has increased over the past century; approximately twice as many extreme U.S. snowstorms occurred in the latter half of the 20th century than the first.[41] As the climate cri~~sis worsens,

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~~[39] NOAA National Centers for Environmental Information (NCEI), U.S. Billion-Dollar Weather and Climate Disasters (2019), https://www.ncdc.noaa.gov/billions/.~~

~~[40] Grinsted, Aslak et al., Homogeneous record of Atlantic hurricane surge threat since 1923, 109 PNAS 19601 (2012); Grinsted, Aslak et al., Projected hurricane surge threat from rising temperatures, 110 PNAS 5369 (2013).~~

~~[41] NOAA, National Centers for Environmental Information (NCEI), Climate Change and Extreme Snow in the U.S. (2019), https://www.ncdc.noaa.gov/news/climate-change-and-extreme-snow-us.~~

~~Atlantic hurricane intensity, rainfall and storm surge are projected to increase further, making hurricanes ever-more destructive.~~[42]

~~Q: MORE GENERALLY, PLEASE SUMMARIZE THE STATE OF SCIENCE ON THE CLIMATE CRISIS.~~

~~A: The science is clear that the world faces a climate emergency. An international scientific consensus has established that human-caused climate change is already causing widespread harms, climate change threats are escalating and becoming increasingly dangerous, and fossil fuels are the dominant driver of the climate crisis.~~

~~The IPCC concluded in its 2014 Fifth Assessment Report that: "[w]arming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, and sea level has risen," and further that "[r]ecent climate changes have had widespread impacts on human and natural systems."~~[43]

~~42 U.S. Global Change Research Program, Climate Science Special Report: Fourth National Climate Assessment, Vol. I (2017), https://science2017.globalchange.gov/ at 257; U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 74, 95.~~

~~43 Intergovernmental Panel on Climate Change, Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (2014) at 2.~~

~~Moreover, the U.S. federal government has repeatedly recognized that human-caused climate change is causing widespread and intensifying harms across the country in the authoritative National Climate Assessments. Most recently, the Fourth NCA, comprised of the 2017 *Climate Science Special Report* (Volume I)[44] and the 2018 *Impacts, Risks, and Adaptation in the United States* (Volume II),[45] concluded that "there is no convincing alternative explanation" for the observed warming of the climate over the last century other than human activities.[46] It found that "evidence of human-caused climate change is overwhelming and continues to strengthen, that the impacts of climate change are intensifying across the country, and that climate-related threats to Americans' physical, social, and economic well-being are rising."[47]~~

~~In addition, in 2009, the U.S Environmental Protection Agency found that the then-current and projected concentrations of greenhouse gas pollution endanger the public health and welfare of current and future generations, based~~

[44] ~~U.S. Global Change Research Program, Climate Science Special Report: Fourth National Climate Assessment, Vol. I (2017), https://science2017.globalchange.gov/.~~

[45] ~~U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018).~~

[46] ~~U.S. Global Change Research Program, Climate Science Special Report: Fourth National Climate Assessment, Vol. I (2017), https://science2017.globalchange.gov/ at 10.~~

[47] ~~U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018) at 36.~~

~~on robust scientific evidence of the harms from climate change.[48] A 2018 study reviewed the scientific evidence that has emerged since 2009 and concluded that this evidence "lends increased support" for EPA's endangerment finding.[49] The study by 16 prominent scientists examined the topics covered by the endangerment finding and concluded that "[f]or each of the areas addressed in the [endangerment finding], the amount, diversity, and sophistication of the evidence has increased dramatically, clearly strengthening the case for endangerment." The study also found that the risks of some impacts are even more severe or widespread than anticipated in 2009.~~

~~The National Climate Assessments also make clear that the harms of climate change are long-lived, and the choices we make now on reducing greenhouse gas pollution will affect the severity of the climate change damages that will be suffered in the coming decades and centuries: "[t]he impacts of global climate change are already being felt in the United States and are projected to intensify in the future—but the severity of future impacts will depend largely on actions taken to reduce greenhouse gas emissions."[50] As the~~

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48 ~~U.S. EPA [U.S. Environmental Protection Agency], Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule, 74 Federal Register 66496 (2009).~~

49 ~~Duffy, Philip B. et al., Strengthened Scientific Support for the Endangerment Finding for Atmospheric Greenhouse Gases, 363 Science 1 (2019) at 1.~~

50 ~~U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at~~ 34.

~~Fourth National Climate Assessment explains: "[m]any climate change impacts and associated economic damages in the United States can be substantially reduced over the course of the 21st century through global-scale reductions in greenhouse gas emissions."[51] As highlighted by the National Research Council: "[E]mission reduction choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia."[52]~~

~~In 2018, the Intergovernmental Panel on Climate Change (IPCC) *Special Report on Global Warming of 1.5°C* provided overwhelming scientific evidence for the necessity of immediate, deep greenhouse gas reductions across all sectors to avoid devastating climate change-driven damages, and underscored the high costs of inaction or delays, particularly in the next crucial decade, in making these cuts. First, the IPCC *Special Report* quantified the devastating harms that would occur at 2°C warming compared with 1.5°C warming, and highlighted the necessity of limiting warming to 1.5°C to avoid catastrophic impacts to people and life on Earth.[53] According to the IPCC's analysis, the damages that~~

~~[51] U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 1347.~~

~~[52] National Research Council, Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia (2011) at 3.~~

~~[53] Intergovernmental Panel on Climate Change, Global Warming of 1.5°C, An IPCC special report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global~~

~~would occur at 2°C warming compared with 1.5°C are stark, including significantly more deadly heatwaves, drought and flooding; 10 centimeters of additional sea level rise within this century, exposing 10 million more people to flooding; a greater risk of triggering the collapse of the Greenland and Antarctic ice sheets with resulting multi-meter sea level rise; dramatically increased species extinction risk, including a doubling of the number of vertebrate and plant species losing more than half their range, and the virtual elimination of coral reefs; 1.5 to 2.5 million more square kilometers of thawing permafrost area with the associated release of methane, a potent greenhouse gas; a tenfold increase in the probability of ice-free Arctic summers; a higher risk of heat-related and ozone-related deaths and the increased spread of mosquito-borne diseases such as malaria and dengue fever; reduced yields and lower nutritional value of staple crops like corn, rice, and wheat; a doubling of the number of people exposed to climate change-induced increases in water stress; and up to several hundred million more people exposed to climate-related risks and susceptible to poverty by 2050.[54]~~

~~response to the threat of climate change, sustainable development, and efforts to eradicate poverty (2018).~~

~~54 IPCC, 2018: Summary for Policymakers. In: Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V. et al. (eds.)] at 7-11.~~

~~Chief among its harms, human-caused climate change poses serious threats to public health and well-being.[55] The Fourth National Climate Assessment concluded that "[t]he health and well-being of Americans are already affected by climate change, with the adverse health consequences projected to worsen with additional climate change."[56] The health impacts from climate change include increased exposure to heat waves, floods, droughts, and other extreme weather events; increases in infectious diseases; decreases in the quality and safety of air, food, and water including rising food insecurity and increases in air pollution; displacement; and stresses to mental health and well-being.[57] Although everyone is vulnerable to health harms from climate change, populations experiencing greater health risks include children, older adults, low-income communities, some communities of color, immigrant groups, and persons with disabilities and pre-existing medical conditions.[58] The 2015 Lancet~~

~~55 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 540; U.S. Global Change Research Program, The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment (2016).~~

~~56 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 540.~~

~~57 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 540; U.S. Global Change Research Program, The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment (2016).~~

~~58 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018),~~

~~Commission on Health and Climate Change warned that climate change is causing a global medical emergency, concluding that "the implications of climate change for a global population of 9 billion people threatens to undermine the last half century of gains in development and global health."~~[59]

~~Climate change-driven health impacts are already occurring in the United States, particularly from illnesses and deaths caused by extreme weather events which are increasing in frequency and intensity.~~[60] ~~Heat is the leading cause of weather-related deaths in the U.S., and extreme heat is projected to increase future mortality on the scale of thousands to tens of thousands of additional premature deaths per year across the U.S. by the end of this century.~~[61] ~~Hot days have been conclusively linked to an increase in heat-related deaths and illnesses—particularly among older adults, pregnant women, and children—including cardiovascular and respiratory complications, renal failure, electrolyte imbalance, kidney stones, negative impacts on fetal health, and preterm birth.~~[62]

~~https://nca2018.globalchange.gov/ at 548; U.S. Global Change Research Program, The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment (2016).~~

~~59 Watts, Nick et al., Health and climate change: policy responses to protect public health, 386 The Lancet 1861 (2015) at 1861.~~

~~60 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 541.~~

~~61 U.S. Global Change Research Program, The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment (2016).~~

~~62 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018),~~

~~One study estimated that nearly one-third of the world's population is currently exposed to a deadly combination of heat and humidity for at least 20 days a year, and that percentage is projected to rise to nearly three-quarters by the end of the century without deep cuts in greenhouse gas pollution, with particular impacts to the southeastern U.S.[63]~~

~~Air pollutants – particularly ozone, particulate matter, and allergens – are expected to increase with climate change.[64] Climate-driven increases in ozone will cause more premature deaths, hospital visits, lost school days, and acute respiratory symptoms.[65] In 2020, projected climate-related increases in ground-level ozone concentrations could lead to an average of 2.8 million more occurrences of acute respiratory symptoms, 944,000 more missed school days, and over 5,000 more hospitalizations for respiratory-related problems.[66] The~~

~~https://nca2018.globalchange.gov/ at 544-545.~~

~~[63] Mora, Camilo et al., Global risk of deadly heat, 7 Nature Climate Change 501 (2017).~~

~~[64] U.S. Environmental Protection Agency, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule, 74 Federal Register 66496 (2009); U.S. Global Change Research Program, The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment, (2016).~~

~~[65] U.S. Global Change Research Program, The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment (2016).~~

~~[66] Union of Concerned Scientists, Rising Temperatures and Your Health: Rising Temperatures, Worsening Ozone Pollution (2011).~~

~~continental U.S. could pay an average of $5.4 billion (2008$) in health impact costs associated with climate-related increases in ozone in 2020.[67]~~

~~Numerous studies have emphasized that many lives could be saved with rapid reductions in greenhouse gas pollution.[68] The Fourth National Climate Assessment concludes that "reducing greenhouse gas emissions would benefit the health of Americans in the near and long term."[69] The Assessment projects that "by the end of this century, thousands of American lives could be saved and hundreds of billions of dollars in health-related economic benefits gained each year under a pathway of lower greenhouse gas emissions."[70] Another recent study reported that faster reductions in carbon pollution will prevent millions of premature deaths globally. Compared with a 2°C pathway, a 1.5°C pathway is projected to result in 153 million fewer premature deaths worldwide due to reduced PM 2.5 and ozone exposure, including 130,000 fewer premature deaths~~

~~67 Union of Concerned Scientists, Rising Temperatures and Your Health: Rising Temperatures, Worsening Ozone Pollution (2011).~~

~~68 Gasparrini, Antonio et al., Projections of temperature-related excess mortality under climate change scenarios, 1 Lancet Planet Health e360 (2017); Hsiang, Solomon et al., Estimating economic damage from climate change in the United States, 356 Science 1362 (2017); Silva, Raquel A. et al., Future global mortality from changes in air pollution attributable to climate change, 7 Nature Climate Change 647 (2017); Burke, Marshall et al., Higher temperatures increase suicide rates in the United States and Mexico, 8 Nature Climate Change 723 (2018); Shindell, Drew et al., Quantified, localized health benefits of accelerate carbon dioxide emissions reductions, 8 Nature Climate Change 723 (2018).~~

~~69 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018) at 541.~~

~~70 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018) at 541.~~

~~in Los Angeles and 120,000 in the New York metropolitan area.[71] The Fourth National Climate Assessment makes clear that human-caused climate change is already leading to substantial economic losses in the U.S. and that these losses will be much more severe under higher emissions scenarios, impeding economic growth: "Without substantial and sustained global mitigation and regional adaptation efforts, climate change is expected to cause growing losses to American infrastructure and property and impede the rate of economic growth over this century."[72]~~

~~The Fourth National Climate Assessment warns: "In the absence of more significant global mitigation efforts, climate change is projected to impose substantial damages on the U.S. economy, human health, and the environment. Under scenarios with high emissions and limited or no adaptation, annual losses in some sectors are estimated to grow to hundreds of billions of dollars by the end of the century. It is very likely that some physical and ecological impacts will be irreversible for thousands of years, while others will be permanent."[73]~~

~~71 Shindell, Drew et al., Quantified, localized health benefits of accelerated carbon dioxide emissions reductions, 8 Nature Climate Change 291 (2018).~~

~~72 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 25.~~

~~73 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 1357.~~

~~By the end of the century, the Fourth National Climate Assessment estimates that warming on our current trajectory would cost the U.S. economy hundreds of billions of dollars each year and up to 10 percent of U.S. gross domestic product due to damages including lost crop yields, lost labor, increased disease incidence, property loss from sea level rise, and extreme weather damage.[74] Ultimately, the magnitude of financial burdens imposed by climate change depends on how effectively we curb emissions. Across sectors and regions, significant reductions in emissions will substantially lower the costs resulting from climate change damages.[75] For example, annual damages associated with additional extreme temperature-related deaths are projected at $140 billion (in 2015 dollars) under the higher RCP 8.5 emissions scenario compared with $60 billion under the lower RCP 4.5 scenario by 2090.[76] Annual damages to labor would be approximately $155 billion under RCP 8.5, but reduced by 48 percent under RCP 4.5.[77] While coastal property damage would~~

~~74 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 1358, 1360.~~

~~75 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 1349.~~

~~76 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 552.~~

~~77 U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 1349.~~

~~carry an annual cost of $118 billion under RCP 8.5 in 2090, 22 percent of this cost would be avoided under RCP 4.5.~~[78]

~~Further, the Fourth National Climate Assessment concluded with very high confidence that continued warming increases the likelihood that the climate system will cross tipping points—large-scale shifts in the climate system—that could result in climate states wholly outside human experience and result in severe physical and socioeconomic impacts.~~[79] ~~The IPCC Fifth Assessment Report similarly warned that "with increasing warming, some physical and ecological systems are at risk of abrupt and/or irreversible changes" and that the risk "increases as the magnitude of the warming increases."~~[80]

~~Evidence that the climate system is already close to crossing critical tipping points also highlights the urgency of implementing emissions cuts.~~[81] ~~For example, research indicates that a critical tipping point important to the stability~~

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78 ~~U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States, Fourth National Climate Assessment, Volume II (2018), https://nca2018.globalchange.gov/ at 1349.~~

79 ~~U.S. Global Change Research Program, Climate Science Special Report: Fourth National Climate Assessment, Vol. I (2017), https://science2017.globalchange.gov/ at 411.~~

80 ~~Intergovernmental Panel on Climate Change, Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (2014) at 72-73.~~

81 ~~Intergovernmental Panel on Climate Change, Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (2014) at 73-74; Lenton, Timothy M. et al., Climate tipping points—too risky to bet against, 575 Nature 592 (2019).~~

~~of the West Antarctic Ice Sheet has been crossed. According to the Fourth National Climate Assessment, "observational evidence suggests that ice dynamics already in progress have committed the planet to as much as 3.9 feet (1.2 m) worth of sea level rise from the West Antarctic Ice Sheet alone" and that "under the higher RCP8.5 scenario, Antarctic ice could contribute 3.3 feet (1 m) or more to global mean sea level over the remainder of this century, with some authors arguing that rates of change could be even faster."[82] A recent analysis suggests the Earth System is at risk of crossing a planetary threshold that could lock in a rapid pathway toward much hotter conditions ("Hothouse Earth") propelled by self-reinforcing feedbacks. This threshold could be crossed at 2°C temperature rise, and the risk will increase significantly with additional warming.[83] A 2019 review of the risks from tipping points by prominent climate scientists concluded that "the evidence from tipping points alone suggests that we are in a state of planetary emergency: both the risk and urgency of the situation are acute."[84]~~

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes, it does.

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82 U.S. Global Change Research Program, Climate Science Special Report: Fourth National Climate Assessment, Vol. I (2017), https://science2017.globalchange.gov/ at 420.

83 Steffen, Will et al., Trajectories of the Earth System in the Anthropocene, 115 PNAS 33 (2018).

84 Lenton, Timothy M. et al., Climate tipping points—too risky to bet against, 575 Nature 592 (2019).

CERTIFICATE OF SERVICE

I hereby certify that the foregoing Testimony of Shaye Wolf, Ph.D. submitted by Intervenors Center for Biological Diversity and Appalachian Voices has been served this day upon each of the parties of record in this proceeding through their attorneys by email transmission.

This 18th day of February, 2020.

Electronically submitted
Perrin W. de Jong
Counsel for Intervenors

MR. CULLEY: Chair Mitchell, Thad Culley with Vote Solar. Also, I'll add on here. We would also make a similar motion for our witnesses, James Van Nostrand and Tyler Fitch who were excused, and their testimony was previously put in at the consolidated hearing, consisting of 103 pages and seven exhibits filed on February 18th. We'd ask that that be moved into the record and copied as if given orally from the stand.

CHAIR MITCHELL: All right. Mr. Culley, hearing no objection, your motion is allowed.

MR. CULLEY: Thank you.

(Whereupon, the direct testimony of James Van Nostrand and Tyler Fitch was copied into the record as if given orally from the stand.)

(Whereupon, Exhibits JMV-TF-1 through JMV-TF-7 were admitted into evidence. Exhibit JMV-TF-3 was filed under seal.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of	)
Application of Duke Energy Carolinas, LLC	)
For Adjustment of Rates and Charges	)
Applicable to Electric Service	)
In North Carolina	)

DIRECT TESTIMONY OF

JAMES VAN NOSTRAND

AND

TYLER FITCH

ON BEHALF OF
VOTE SOLAR

FEBRUARY 18, 2020

TABLE OF CONTENTS

LIST OF EXHIBITS

1. INTRODUCTION

A. JAMES M. VAN NOSTRAND

Q. Please state your name, title and employer.

A. My name is James M. Van Nostrand. I am an Energy Policy Expert for EQ Research, a consulting firm based out of Cary, North Carolina. I am also a Professor of Law at the West Virginia University College of Law, where I teach energy and environmental law and Direct the Center for Energy and Sustainable Development.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Please state your educational and professional experience.

A. Exhibit JMV-TF-1 sets forth my educational background and professional experience.

B. TYLER FITCH

Q. Please state your name, title, and employer.

A. My name is Tyler Fitch. I am Southeast Regulatory Manager for Vote Solar.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Please state your educational and professional experience.

A. Exhibit JMV-TF-2 sets forth my educational background and professional experience.

C. OVERVIEW OF JOINT TESTIMONY

Q. Does each sponsoring witness adopt the whole of this testimony?

A. Yes. However, Mr. Fitch is not a lawyer and defers to Mr. Van Nostrand regarding any portion of this testimony that could be perceived as requiring legal training to answer.

Q. Please summarize your testimony.

A. This testimony focuses on the Company's proposed Grid Improvement Plan and its request to recover the costs of the Plan through deferral to a regulatory asset. In particular, our testimony examines the extent to which the Company has integrated the impact of climate change-related risks in its Grid Improvement Plan. Since 2017, risks related to climate change have emerged as a material factor in electric utility operations. Recent developments in climate risk assessment, scrutiny from shareholders, and regulatory momentum underscore the need to manage these risks. Given the exposure faced by the Company to climate change-related risks due to, among other things, the vulnerability of physical assets to more frequent and intense extreme weather events as well as the impact on its system associated with increasing temperatures, prudent utility practice requires that these risks be considered as part of any long plan for transmission and distribution investments. Our testimony concludes that the Company's analysis of climate change-related risks in connection with its Grid Improvement Plan is woefully inadequate, and it is doubtful that the Company has sustained its burden of proof to demonstrate that the proposed expenditures associated with the Plan are necessary and reasonable. Our testimony concludes with several recommendations to improve the integration of climate change-related risks in the Company's long-term system planning, as well as a possible regulatory mechanism that would provide incentives for implementation of these recommendations.

Our testimony reaches the following conclusions:

- Climate-related risks, emerging in many vectors, have a material and substantial bearing on the Company's operations today and will continue to affect operations in the future. Collaborative processes in North Carolina are currently underway to assess these risks and their implications for the electric grid.
- The Company faces demonstrable physical risks from climate change and increasing scrutiny on climate risk management from relevant financial institutions.
- As a potential foundational investment for the 21st century grid, any grid modernization plan should consider best climate resilience practices alongside grid modernization best practices. This includes the fair assessment of distributed energy resources as climate resilience and grid modernization solutions.
- The Grid Improvement Plan, as filed, does not assess or respond to climate-related risks, nor does it adhere to grid modernization best practices. As a result, the Company's proposal does not provide enough information to indicate that the Plan is a prudent investment.

Our testimony includes the following recommendations:

- The Commission should direct the Company to assess and manage climate-related risks across its operations and assets, in accordance with prudent utility practice.
- The Commission should make clear that it will apply this standard to Grid Improvement Plan investments by the Company.
- The Commission should direct the Company to participate in ongoing Department of Environmental Quality stakeholder processes around grid modernization and integrate data, findings, and recommendations, into its grid modernization investments. The Commission should further require that the Company file a report by December 31, 2020 identifying any gaps in knowledge that need to be filled through further collaboration.
- The Commission should require the Company to develop large distribution investments such as the Grid Improvement Plan through an integrated distribution planning (IDP) or integrated systems & operations planning (ISOP) process moving forward.
- To the extent that Grid Improvement Plan projects are permitted deferred recovery, the Commission should impose performance-based conditions on the recovery of such deferred amounts in rates, such as through adjustments to the weighted average cost of capital applied to the unamortized balance of deferred amounts.

Q. How is your testimony organized?

A. The testimony is presented in several sections:

- **Section 2** provides context for the Grid Improvement Plan based on the Company's recent Power/Forward proposal, grid modernization best practices, and the response of the Commission. It also describes Vote Solar's experience as a stakeholder in the Company's Grid Improvement Plan stakeholder process.
- **Section 3** introduces the concept of climate-related risks, and demonstrates the extent to which such risks are at play in the Company's application. Section 3 includes a comprehensive review of the Company's exposure to such risks and best practices for managing them.
- **Section 4** identifies several policy and regulatory developments in North Carolina that may have bearing on any grid modernization process.
- **Section 5** presents a review of the Grid Improvement Plan's development based on grid modernization and climate resilience best practices as well as ongoing North Carolina developments.
- **Section 6** offers a specific discussion of the Company's request for deferred accounting, integrated systems planning, and the role of climate-related risks at the Commission.
- **Section 7** briefly discusses ratepayer interests in light of climate-related risks.
- **Section 8** provides our conclusions and recommendations to the Commission.

2. POWER/FORWARD, STAKEHOLDER ENGAGEMENT, AND THE DEVELOPMENT OF THE GRID IMPROVEMENT PLAN

Q. Does the Grid Improvement Plan represent the Company's first proposed comprehensive investment plan for its transmission and distribution infrastructure?

A. No. The Company proposed the Power/Forward program in its last rate case.

Q. What was Power/Forward?

A. Power/Forward was a 10-year, $13 billion grid modernization plan for the Duke Energy Carolinas and Duke Energy Progress's transmission and distribution system proposed in the Company's 2017 General Rate Case.[1] Like the Grid Improvement Plan, the stated goals of Power/Forward included improving reliability and integrating distributed resources, and projects included distribution line undergrounding and a 'self-optimizing' grid.[2] The Company proposed a Grid Reliability and Resiliency Rider or deferral into a regulatory asset for recovering Power/Forward costs.[3]

Q. What was Vote Solar's role in that proceeding?

A. Vote Solar's then Regulatory Director, Dr. Caroline Golin, testified on behalf of the North Carolina Sustainable Energy Association in both the Duke Energy

[1] Direct Testimony of David B. Fountain on behalf of Duke Energy Carolinas, Docket No. E-7, Sub 1146. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=fe5827ae-5c88-4efb-9860-959611a22791.
[2] Direct Testimony of Robert M. Simpson III on behalf of Duke Energy Caorlinas, Docket No. E-7, Sub 1146. Retrieved at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=7d4ecffa-40c0-4e89-822d-5cd788b2fcf3.
[3] Direct Testimony of Jane L. McManeus on behalf of Duke Energy Carolinas, Docket No. E-7, Sub 1146. Retrieved at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=4701a724-c7aa-4ff0-bc30-1da295d6f57f.

Carolinas and Duke Energy Progress proceedings. Her testimony assessed the appropriate treatment of a capital-intensive proposal, the prudency of the Power/Forward program (according to the program's overall cost-effectiveness) and its satisfaction of grid modernization best practices, namely:

- Clear and Measurable Goals
- Stakeholder Engagement
- Integrated Distribution Planning
- Cost/Benefit Analysis[4]

Dr. Golin's assessment found that Power/Forward was not justified on an economic or engineering basis and that it failed to implement any of the grid modernization best practices listed above. Dr. Golin recommended that the Commission deny the Company's proposal and proactively establish a separate proceeding for a stakeholder-driven, staff-facilitated process for evaluating grid modernization investments.[5]

Q. Do you agree with Dr. Golin's identification of best practices and establishment of a separate proceeding for grid modernization programs?

[4] Direct Testimony of Caroline Golin on Behalf of NCSEA, Docket No. E-2, Sub 1142. Retrieved at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=4dc8a933-d7c8-4ace-b9ab-e53b8e5690d5.
[5] Direct Testimony of Caroline Golin on Behalf of NCSEA, Docket No. E-7, Sub 1146. Retrieved at https://votesolar.org/files/2215/1741/2799/Direct_Testimony_of_Caroline_Golin_2.pdf.

A. We do. These best practices are supported by grid modernization experts who have presented them across the Southeast and across the country.[6,7,8,9]

Q. What did the Commission find in its decision on the Power/Forward proposal?

A. The Commission noted that, given that the Company controls the timing of the investments and that regulatory lag has not been an issue for these types of investments in the past, a rider would be inappropriate for grid investments.[10] Further, the Commission found that the reasons cited by the Company to justify the Program do not qualify as extraordinary:

> The Commission finds and concludes that the reasons DEC says underlie the need for Power Forward are not unique or extraordinary to DEC, nor are they unique or extraordinary to North Carolina. Weather, customer disruption, physical and cyber security, and aging assets are all issues the Company… [has] to confront in the normal course of providing electric service. The Commission further finds that … a number of the Power Forward programs and projects … are the kinds of activities in which the Company engages or should engage on a routine and continuous basis. Therefore, the

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[6] Alvarez, P., & Stephens, D., (2019, January). Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. *GridLab*. Retrieved at http://gridlab.org/wp-content/uploads/2019/04/GridLab_SC_GridMod.pdf.

[7] Aggarwal, S., & O'Boyle, M., (2017, February). Getting the Most out of Grid Modernization. Energy Innovation. Retrieved at http://ipu.msu.edu/wp-content/uploads/2018/01/Grid-Modernization-Metrics-and-Outcomes-2017.pdf.

[8] Migden-Ostrander, J., & Hauser, S., (2018, September). Grid Modernization and New Utility Business Model. *Regulatory Assistance Project & GridWise Alliance*. Presentation given to Clean Energy Legislative Academy. Retrieved at https://www.raponline.org/wp-content/uploads/2018/09/rap_migden_cnee_legislator_academy_2018_sep_11.pdf.

[9] Migden-Ostrander, J., Littell, D., Shipley, J., Kadoch, C., Sliger, J., (2018, February). Recommendations for Ohio's Power Forward Inquiry. *Regulatory Assistance Project*. Retrieved at https://www.raponline.org/wp-content/uploads/2018/02/rap-recommendations-ohio-power-forward-inquiry-2018-february-final2.pdf.

[10] Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146 et al. p. 142-145. Retrieved at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.

Commission must conclude that Power Forward costs are not appropriate to be considered for deferral accounting.[11]

While the Commission found arguments for a separate proceeding "compelling," it ultimately directed the Company to utilize existing dockets for grid modernization proposals, of which one (the "Smart Grid Technology Plan" docket) is no longer active. The Commission also directed the Company to "engage and collaborate with stakeholders" to address issues raised in the proceeding.[12]

Q. How did the Company engage and collaborate with stakeholders between the conclusion of the previous rate case and this one?

A. Since the last rate case, the Company held three in-person stakeholder workshops that were facilitated by a third party and conducted a series of webinars. Company Witness Oliver describes the objectives of the first stakeholder workshop as to "[d]evelop understanding of proposed investments; hear and explore stakeholder feedback; and support a collaborative process going forward."[13]

Q. In what capacity did Vote Solar participate in the Grid Improvement Plan stakeholder process?

A. Vote Solar participated in all three of the in-person stakeholder workshops held by the Company and observed several of the Company's webinars.

Q. What is Vote Solar's interest in the grid modernization broadly and the Grid Improvement Plan specifically?

[11] *Ibid.,* p. 146.
[12] *Ibid.,* p. 149.
[13] Direct Testimony of Company Witness Jay W. Oliver ("Oliver Direct"), p. 47, ll. 3-5.

A. As with Dr. Golin's previous testimony, Vote Solar believes that decisions on how states pursue grid modernization represent critical opportunities for our electric grid. Done correctly, the modernization of the grid can enable a system where customers see economic benefits, distributed energy resources are evaluated fairly, innovative solutions have a chance to compete with traditional investments, the grid's environmental impact is reduced, and energy service is more reliable and resilient to shocks and stressors. An inappropriate grid modernization proposal, however, could create more costs for customers than benefits, and could fail to deliver on promised benefits. As the onset of climate-related risks affects the risk profile for many grid stakeholders, the need to get grid modernization right is even more urgent. Vote Solar participated in the stakeholder process in pursuit of a grid modernization process in North Carolina that adheres to the best practices cited in Dr. Golin's testimony and ultimately one that works toward a more dynamic, resilient, and distributed grid.

Q. Mr. Fitch, please characterize your experience as a stakeholder in this collaboration process.

A. I will characterize my direct experience as an in-person stakeholder in the third workshop and webinars, and base my review of the first and second workshop on pre-read packets and workshop readout reports provided as exhibits in this proceeding by Witness Oliver. I found the stakeholder workshops valuable insofar as they clarified the Company's justification of its proposal and provided an opportunity for stakeholders to share perspectives and goals for a grid modernization process. I cannot characterize the workshops as 'collaborative,' in the true definitional sense of a process where stakeholders would be expected to have more input on shaping the objectives or parameters of the process. In general, the prevailing feeling during workshops was unidirectional information-sharing by the Company. Stakeholders did not appear to play a role in choosing which investments should be selected, or shaping the process by which the Grid Improvement Plan was developed.

Relatedly, I was surprised to find that the Company invited stakeholder input only after the Company had developed the Grid Improvement Plan.[14] This approach leaves stakeholders out of the most important elements of the grid modernization process—defining a shared set of goals and criteria for success, identifying possible solutions, and developing a process for selecting those solutions. In effect, the Plan was 'already baked' by the time stakeholders were given a chance to share ideas.

This procedural element may be a reason that management of climate-related risks, an element that several stakeholders called for, was not included in the Plan.[15] The Company in fact explicitly stated that it intended to avoid the term "climate change," and the topic would be addressed only to the extent climate

[14] Oliver Direct, p. 32, l. 14 to p. 33, l. 20.
[15] Oliver Direct Ex. 13, p. 12.

change risks were captured as part of the megatrend identified as "Environmental Trends" and "Impact of Weather Events."[16]

Q. Mr. Fitch, is it clear to what extent differences between programs proposed in the Power/Forward and the Grid Improvement Plan were driven by stakeholder input?

A. No. Witness Oliver represents that the stakeholder process led to the Company's creation of the Megatrends,[17] but the excerpt of the Commission's 2018 order cited above shows that several of these Megatrends were previously used to justify the Power/Forward plan. In any case, the Plan's similarity to Power/Forward (further discussed below) would indicate that the Megatrends may operate in this case as a *post hoc* justification.

Company Witness Oliver cites several other changes to the plan as stakeholder-driven, [18] but a review of the workshop readout demonstrates more nuance at play: Integrated Volt-Var Control ("IVVC") was added, but a similar program was already in operation in DEP territory;[19] targeted undergrounding was reduced, but the workshop readout report described this project as changing priority;[20] and the distribution hardening & resiliency program reduced in size, but the term 'distribution hardening' does not appear in the workshop readout report.[21]

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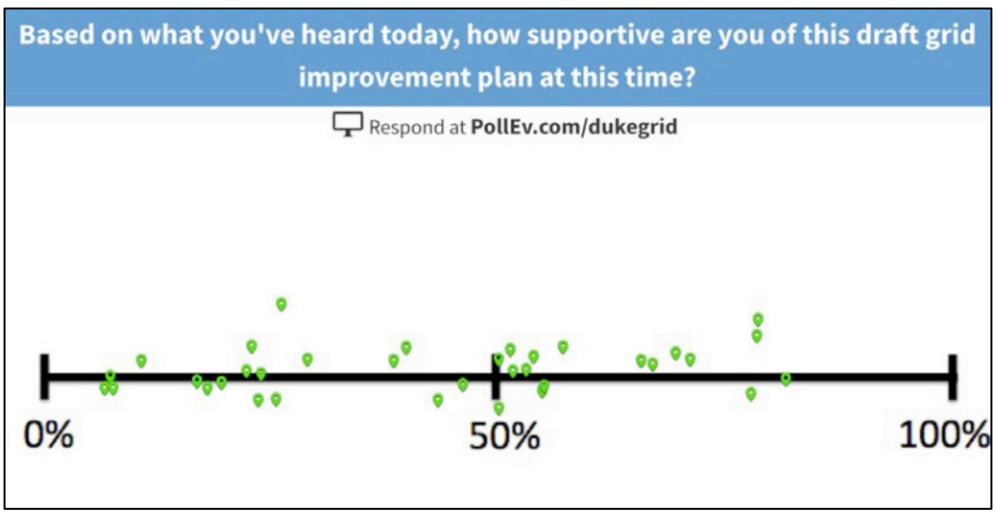
[16] Oliver Direct, Ex. 13, p. 29.
[17] Oliver Direct, p. 47, ll. 10-11.
[18] Oliver Direct, p. 47, ll. 13-15.
[19] Oliver Direct, Exhibit 12, p. 46.
[20] Oliver Direct, Exhibit 11, p. 12-13.
[21] *Ibid.,* p. 144.

Q. Based on the workshop readout reports, what were other stakeholders' responses to the stakeholder process?

A. The Company rolled out its Grid Improvement Plan proposal at the second stakeholder workshop in November 2018. The readout report registers that stakeholders had a mixed, at best, view of the Plan, as shown in Figure 1. Key takeaways from the workshop included a note that stakeholders asked the Company to explicitly include climate change as a megatrend and to better understand the DER-enablement implications of their proposal.[22]

Figure 1. Stakeholder Sentiment of Grid Improvement Plan.[23]



The third stakeholder workshop represented more of a 'deep dive' into the cost-benefit methodology of several proposed programs, with the Company's stated intention to file a rate case application including a Grid Improvement Plan in the

[22] Oliver Direct, Ex. 13, p. 12.
[23] Figure is directly taken from Oliver Direct, Ex. 13, p. 22.

next several months looming over the conversation.[24] At the last workshop before the Plan's submission to the Commission, the role of stakeholder input was still unclear to stakeholders:

> "Several stakeholders felt unclear about the impact from current stakeholder engagement, and if/how stakeholder input has and will be meaningfully used in the GIP riling. In response, many stakeholders requested to see evidence and/or explicit explanations demonstrating how stakeholder feedback has thus far been incorporated."[25]

Of course, stakeholders at the Grid Improvement Plan workshops showed a wide range of opinions and interests, and the summary above is not meant to be comprehensive. It does, however, point to a trend of stakeholders (Vote Solar included) finding that the process did not meaningfully incorporate stakeholder input into proposed investments.

Q. Mr. Fitch, did the stakeholder process the Company conducted in advance of this rate case adhere to stakeholder best practices or a reasonable expectation of engagement and collaboration?

A. The stakeholder process did not allow stakeholders to set goals for the Plan or work with the Company to identify criteria for evaluating solutions. Especially for the third workshop, stakeholder input was not likely to alter the Company's proposal to the Commission. Although, to my knowledge, the Company has not committed to a cyclical, ongoing stakeholder process, the potential for that type of process

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[24] Oliver Direct, Ex. 16, p. 6: "Several stakeholders were skeptical about how a "clean slate" for stakeholder engagement could be realized after the filing this year."
[25] Oliver Direct, Ex. 16., p. 5-6.

through the Company's proposed phases is possible. Overall, however, the stakeholder process did not adhere to these best practices.

Q. Please compare the Company's proposed Grid Improvement Plan to its previous Power/Forward plan.

A. The Company provided a comparison between the Grid Improvement Plan and Power/Forward during its April 2019 webinar,[26] and provided a more precise comparison between the programs in discovery.[27] Every program that made up Power/Forward is represented in the Grid Improvement Plan, although the total budgets for targeted undergrounding and "incremental distribution hardening & resilience" have decreased substantially. Several new programs populate the GIP, including security measures, IVVC, integrated systems & operations planning, and support for energy storage and EVs. Even so, over 80% of the capital investment that comprises the Grid Investment Plan is derived from projects that were also a part of Power/Forward.[28] In a literal sense, then, the Grid Improvement Plan for the most part comprises Power/Forward projects. The Grid Improvement Plan's scope is much smaller than Power/Forward's (3 years versus 10 years), but the Company has described at least one more "phase" of the Grid Improvement Plan.[29]

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[26] Oliver Direct, Ex. 14 p. 10.
[27] Company Response to NCSEA Data Request 3-7.
[28] *Ibid.* Investment in SOG, Incremental Transmission H&R, Transmission Bank Replacement, Oil Breaker Replacement, T&D Communications, Distribution System Automation, Transmission System Intelligence, and T&D Enterprise systems totals $1.952 billion, which is ~84% of the $2.3 billion budget.
[29] Oliver Direct, p. 51, ll. 1 to p. 52, ll. 16.

Q. Mr. Fitch, how did the Company portray its Integrated Systems & Operations Planning ("ISOP") project in Company meetings and webinars?

A. ISOP presentations[30] portrayed ISOP as a way to integrate planning processes across generation, transmission, distribution, and customer services,[31] and identified capabilities of the Advanced Distribution Planning component of ISOP to include "optimized selection of both traditional and non-traditional solutions."[32]

Q. What appears to be the relationship between ISOP and the Grid Improvement Plan?

A. ISOP is as a identified component of the Grid Improvement Plan. It is not apparent from the Company's materials in what order Grid Improvement Plan projects will be implemented, despite the clear value that the capabilities of ISOP, ADP, and Morecast would bring toward identifying grid needs and placing solutions.

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[30] Mr. Fitch reviewed Duke Energy's presentation of ISOP to the Commission on August 28, 2019, and observed the ISOP webinar on January 30, 2020.
[31] Duke Energy (2019, August), Integrated Systems & Operations Planning (ISOP) Technical Conference. *North Carolina Utilities Commission*, p. 5. Retrieved at: https://www.duke-energy.com/_/media/pdfs/our-company/isop/isop-ncuc-conference-overview-rev0.pdf?la=en.
[32] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (2019, August). Response to Commission Questions in July 23, 2019 Order Docket No. E-100, Sub 157. Retrieved at https://www.duke-energy.com/_/media/pdfs/our-company/isop/e100-sub157-decdep-response-to-ncuc-questions.pdf?la=en.

3. ONSET OF CLIMATE-RELATED RISK AND FUNDAMENTAL CHANGES IN THE ELECTRIC UTILITY SECTOR

A. Introducing Climate-Related Risks

Q. Why is climate change relevant to the Company's general rate case application?

A. In its response to Vote Solar's motion to compel responses to discovery, the Company stated that the words climate change or global warming do not appear in its application,[33] and posited that the scope of this proceeding is "limited to the costs, revenues, rates, and regulatory mechanisms reflected in its application."[34] We agree. As we show below, climate-related risks clearly influence the costs, revenues, rates, and regulatory mechanisms in the current application. Whether or not the Company explicitly uses the term "climate-related" or "climate change" in its application, the physical impacts of climate change and the regulatory and societal responses to it have real, material implications for the Company and the prudency of current proposals in its Application. The following are items in the Company's application and their climate-related risk implications:

- The Grid Improvement Plan purports to "mitigate the impact of major storm events,"[35] "reinforce equipment in flood-prone areas,"[36] and "support more rooftop solar, battery storage, electric vehicles, and microgrids."[37] Storm and flood risks are likely to change due to climate

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[33] Duke Energy Carolinas, LLC's Response to Opposition to Motion to Compel Discovery, p. 2.
[34] *Ibid.* p. 4.
[35] Duke Energy Carolinas, LLC Application to Adjust Retail Rates, Request an Accounting Order, and to Consolidate Dockets ("DEC Application"). p. 9.
[36] *Ibid.*
[37] *Ibid.,* p. 10.

change,[38] and Executive Order 80[39] and the Clean Energy Plan,[40] both of which cite climate-related risks as a driver, urge policy adoption that are intended to increase customers' adoption of rooftop solar, battery storage, electric vehicles and microgrids.

- Storm costs from Hurricanes Florence and Michael and Winter Storm Diego.[41] The frequency and intensity of those storms is increasing, which the Company acknowledges.[42] But if the Company does not update storm preparation to account for this reality there will be implications for the Company's assets[43] and the ability of its customers to cope with the impacts of those storms.[44]

- Investments to upgrade Company assets to co-fire gas and coal.[45] Switching to lower-carbon fuels reduces regulatory climate-related risk in the future. The application notes that when it explains that the investments will "further reduce carbon emissions across the Carolinas for the benefit of customers."[46]

- Accelerated depreciation for coal assets.[47] Again, this acts as a hedge against potential climate regulation, and the application and Witness DeMay argue that investing in cleaner energy sources is done "for the benefit of [the Company's] customers."[48,49]

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[38] Kunkel, K., & Easterling, D., (2020, January). North Carolina Climate Science Report. Presentation given to North Carolina Climate Change Interagency Council, p. 28. Retrieved at https://files.nc.gov/ncdeq/climate-change/interagency-council/Jan-22-2020--Interagency-Climate-Council-presentation-rev.pdf.
[39] State of North Carolina Exec. Order No. 80, (2018, October).
[40] North Carolina Department of Environmental Quality, (2019, October), North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System. Retrieved at: https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.
[41] DEC Application, p. 6.
[42] *Ibid.* p. 9.
[43] Morehouse, C., (2020, January), Ameren, Xcel, Dominion, Duke among most at-risk from changing climate: Moody's. Retrieved at https://www.utilitydive.com/news/ameren-xcel-dominion-duke-among-most-at-risk-from-changing-climate-mood/570789/.
[44] ConEdison (2019, December). Climate Change Vulnerability Study. p. 31. Retrieved at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.
[45] Duke Energy Carolinas, LLC Application to Adjust Retail Rates, Request an Accounting Order, and to Consolidate Dockets ("DEC Application"). p. 5, #9.
[46] *Ibid.*
[47] *Ibid.* p. 8.
[48] *Ibid.*
[49] Direct Testimony of Company Witness Stephen G. De May ("De May Direct"), p. 14, l. 6

- The Company reviews its approved return on equity.[50] Witness Hevert does not mention that Moody's credit opinions for the Company in 2018 and 2019 mention its "carbon transition risk,"[51] thereby failing to capture a recent significant pivot in how the financial industry views climate-related risks.

These items show that the Company's decisions today are influenced by climate-related risks and affect the Company's future exposure to those risks. We will note that this is not an exhaustive list of climate-related risks to the Company. Climate-related risks operate through multiple vectors beyond physical impacts and are complex and inter-related. Avoidance of, or, conversely, engagement with, these risks is very likely to impact the Company's operations and financial position, as we discuss below.

In response to discovery on how it manages climate-related risks, the Company states that "[it], as well as its stakeholders, are unable to say with certainty what the future impacts of climate change may or may not be."[52] This is not a responsible or mainstream approach to risk management. As expressed by State Street CEO Ronald O'Hanley in his recent statement to the *Wall Street Journal* on climate-related risks:

> "Does anyone know with certainty or precision what the scope and pace of climate change might mean for long-term investments? No. But that is the textbook definition of risk: More things can happen than will happen."[53]

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[50] DEC Application. p. 13.
[51] Company Response to Public Staff Data Request 38-5.
[52] Company Response to Volte Solar Data Request 3-24.
[53] O'Hanley, R., (2020, January). Sustainability Is Part of Good Risk Assessment. *Wall Street Journal*. Retrieved at https://www.wsj.com/articles/sustainability-is-part-of-good-risk-assessment-11580413295#comments_sector.

As in any business, risk management is fundamental to prudent business practice. As we demonstrate, the Company and Commission are better equipped than ever before to consider climate change's material risks.

Q. What are climate-related risks?

A. Climate-related risks refer to the potential negative impacts of climate change on a firm or organization. Risks may emerge as a result of the physical shocks and stresses of climate change (physical risks), or the social and economic response to those impacts (transition risks). Importantly, the risks discussed here are those borne by the firm alone, not by its customers or society as a whole. As such, the climate-related risks described here are no different than any other business risk that a firm might assess and manage in the course of prudent operation.

Due to the carbon emissions embedded in conventional electricity generation and the nature of transmission and distribution infrastructure, electric utilities are among the most vulnerable industries to climate-related risk.[54] Climate-related risks that electric utilities face are categorized below:

- **Physical:** Impacts to assets and operations from physical climate impacts.
- **Financial:** Impacts to cost-of-capital due to climate-related exposure and confidence in risk management.

[54] The Task Force on Climate-Related Disclosures identified the energy sector, including electric utilities, as one of four non-financial groups with "the highest likelihood of climate-related financial impacts." Task Force on Climate Related Financial Disclosures, (2017, June). Recommendations of the Task Force on Climate-Related Disclosures. P. 16. Retrieved at: https://www.fsb-tcfd.org/wp-content/uploads/2017/06/FINAL-2017-TCFD-Report-11052018.pdf.

- **Economic:** Risk of stranded assets or decreased sales due to increased viability of alternatives.
- **Regulatory:** Impacts to operating and capital costs from changing regulations.
- **Reputational:** Potential loss of goodwill due to perceived response to climate change.

Although these categories are helpful for inventorying different types of risk, climate-related risks are complex and interconnected.[55] It is for this reason that understanding these risks as related to each other and specifically related to climate change is important.

For each dimension of risk, we summarize the mechanism by which it impacts utility operations, provide an overview of state-of-the-art efforts to characterize the risk, and describe the Company's potential exposure.

Q. Does the broader business and financial community consider these risks material? Has the perception or assessment of these risks changed since the Company's last rate case?

A. While climate change and its attendant business risks may be a lightning rod topic for some, Company witness DeMay observes—and we agree—that "[t]he energy sector is in a period of transformation and profound change," due to technological advancements, environmental mandates, notions of resiliency, and changing customer expectations.[56] Climate-related risks encapsulate these transformative

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[55] *Ibid.,* p. 10.
[56] Direct Testimony of Company Witness Stephen G. Demay ("Demay Direct"), p. 5, ll. 18-21.

changes, and the industry has reached a tipping point since the Company's last rate case application in 2017. Six key developments are driving this transformation:

First, a common framework for understanding, disclosing, and managing climate-related risks is emerging. At the request of the G20, the Financial Stability Board formed the Task Force on Climate-related Financial Disclosures ("TCFD") in 2015 to develop a universal framework for risk disclosure. The TCFD's final recommendations were published on June 15, 2017—just over a week after the Commission opened a docket for the Company's 2017 rate case.[57] Since then, TCFD's recommendations have become the international standard, adopted by almost 800 organizations representing over $118 trillion in assets.[58]

Second, awareness of the here-and-now risks of climate change to electric utilities—and the urgent need to mitigate those risks—have materialized since 2017. The California wildfires and related PG&E bankruptcy and large-scale public service power shutoffs in response to fire risks have galvanized public conversation about the role of electric utilities in mitigating climate impacts.[59] One Wall Street

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[57] State of North Carolina Utilities Commission, Order Consolidating Dockets., Docket No. E-2, Sub 1142, E-2, Sub 1103 and E-7, Sub 1110. Retrieved here: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=d7713362-d657-43f2-afd7-f01145dd294e

[58] Task Force on Climate-related Financial Disclosures, (2019, May). 2019 Status Report. pp. 2. Retrieved at https://www.fsb-tcfd.org/publications/tcfd-2019-status-report/.

[59] Gold, R., (2019, January), PG&E: The First Climate-Change Bankruptcy, Probably Not the Last. *Wall Street Journal.* Retrieved at https://www.wsj.com/articles/pg-e-wildfires-and-the-first-climate-change-bankruptcy-11547820006.

Journal headline aptly summarizes the new orientation toward climate-related damages: "For the Economy, Climate Risks are No Longer Theoretical."[60]

Public and private institutions have responded to these impacts. Since 2017, seven US states made commitments to 100% renewable energy,[61] and eleven of the country's largest utility holding companies, including Duke Energy, have announced deep emissions reduction goals.[62] In section 4, we address the related developments in North Carolina policy, including Executive Order 80 and the Clean Energy Plan, bring a similar awareness and anticipation of climate change's physical, social, and economic changes into this jurisdiction.

<u>Third</u>, major financial institutions are taking the onset of climate-related risks seriously. The U.S. Commodity Futures Trading Commission, understanding the implications of these risks, created a climate-related financial risk subcommittee to provide insights and recommendations to market regulators and participants.[63] Larry Fink, CEO of the world's largest asset manager BlackRock, recently addressed climate-related risks as the driver of a "fundamental re-shaping

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[60] Ip, G., (2019, January), For the Economy Climate Risks Are No Longer Theoretical. *Wall Street Journal.* Retrieved at https://www.wsj.com/articles/for-the-economy-climate-risks-are-no-longer-theoretical-11579174209.
[61] UCLA Luskin Center for Innovation, (2019, November), Progress Toward 100% Clean Energy in Cities & States Across the US. Retrieved at https://innovation.luskin.ucla.edu/wp-content/uploads/2019/11/100-Clean-Energy-Progress-Report-UCLA-2.pdf.
[62] Gearino, D., (2019, October), Utilities Are Promising Net Zero Carbon Emissions, But Don't Expect Big Changes Soon. *InsideClimateNews*. Retrieved at https://insideclimatenews.org/news/15102019/utilities-zero-emissions-plans-urgency-coal-gas-duke-dte-xcel.
[63] Litterman, R., (2019, December), Remarks to the Market Risk Advisory Committee. *U.S. Commodity Futures Trading Commission.* Retrieved at https://www.cftc.gov/media/3181/MRAC_Litterman121119/download.

of finance" in his annual letter to global CEOs.[64] Fink's letter, and research from BlackRock's Investment Institute,[65] also contend that climate-risks are already present in utility stocks, but they haven't been adequately evaluated by investors. As those risks become clearer, Fink writes, "In the near future—and sooner than most anticipate—there will be a significant re-allocation of capital."[66] BlackRock's position as one of the largest and most influential investors in the world lends credence to these claims. Notably, BlackRock is the 2nd largest individual shareholder in Duke Energy Corporation.

Institutional investors see managing climate-related risks as part of their fiduciary duty to protect the long-term health of their investments. In February 2019, twenty of the world's largest institutional investors, representing over $1.8 trillion in assets, sent a letter to Duke Energy and other electric utilities indicating that "As long-term investors, we view these [climate-related] risks as significant and material," and calling on firms to set a net-zero by 2050 goal over the next six months.[67] Duke Energy Corporation published their net-zero by 2050 goal seven months later, in September 2019.[68]

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[64] Fink, L., (2020, January), A Fundamental Reshaping of Finance. *BlackRock*. Retrieved at: https://www.blackrock.com/corporate/investor-relations/larry-fink-ceo-letter
[65] Bertolotti, A., Basu, D., Akallal, K., Deese, B., (2019, March), Climate Risk in the US Electric Utility Sector: A Case Study. *BlackRock Investment Institute*. Retrieved at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3347746.
[66] Fink, 2020.
[67] California Public Employees Retirement System et al., (2019, February). *Institutional Investor Statement Regarding Decarbonization of Electric Utiltiies*. Retrieved at https://www.climatemajority.us/investorstatement-20190228.
[68] Duke Energy (2019, September). Duke Energy aims to achieve net-zero carbon emissions by 2050. Retrieved at https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050.

Fourth, analytical capability to understand climate risks at a granular level has improved by leaps and bounds in the last several years. Analysts are capable of projecting climate-related risks and impacts on a single-county level.[69] One recent study of electric utilities viewed risks on a plant-by-plant basis.[70] Credit rating agencies Moody's and S&P are increasing their in-house analytical capacity on this front, and in January 2020 Moody's released its first comprehensive assessment of climate risk for electric utilities.[71]

Fifth, state regulatory regimes are developing best practices for understanding vulnerability to climate-related risks and crafting specific implementation plans for addressing them. After Superstorm Sandy, the New York Public Service Commission convened a Grid Hardening & Resiliency Collaborative to reach consensus on risks to the Con Edison system and approaches to managing them—a move that has been hailed as a "nationwide model"[72, 73] and

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[69] Larsen, K., Larsen, J., Delgado, M., Herndon, W., Mohan, S, (2017, January) Assessing the Effect of Rising Temperatures: The Cost of Climate Change to the U.S. Power Sector. Rhodium Group, p. 10-19. Retrieved at https://rhg.com/wp-content/uploads/2017/01/RHG_PowerSectorImpactsOfClimateChange_Jan2017-1.pdf.
[70] Bertolotti, et al. (2019).
[71] For the convenience of the Commission, the complete Moody's report is filed as a separate confidential exhibit (Exhibit JMV-TF-3-CONFIDENTIAL). All representations about the content of this confidential exhibit in this public (non-confidential) testimony are derived from existing public reporting.
[72] Ralff-Douglas, K., (2016, June). Climate Adaptation in the Electric Sector: Vulnerability Assessments & Resiliency Plans. *California Public Utility Commission*, p. 5. Retrieved at https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/PPD%20-%20Climate%20Adaptation%20Plans.pdf.
[73] Case 13-E-0030 *et al.;* Con Edison's Electric, Gas, and Stream Rates -- Order Approving Electric, Gas, and Steam Rate Plans in Accord with Joint Proposal (2014, February). State of New York Public Service Commission. Retrieved at: https://climate.law.columbia.edu/sites/default/files/content/docs/Final-Order-2014-02-21%20(1).pdf.

an innovative approach[74] for managing climate-related risks. In partnership with the collaborative, Con Edison released its Climate Change Vulnerability Study in December 2019. This study represents a leap forward in its specificity, and the utility will develop an implementation plan to address risks throughout 2020. A copy of the Climate Change Vulnerability Study is provided as Exhibit JMV-TF-4.

Sixth, analysts and investors are urging firms to take action in the short-term. The U.S. Global Change Research Project concludes that utilities are already subject to climate-related physical risks.[75] The United Nations Principles for Responsible Investment summarize the point succinctly: "Failure to consider all longterm investment value drivers, including [environmental, social, and governance] issues, is a failure of fiduciary duty."[76]

To recap, there is a common understanding of climate-related risks; investors and the public are taking these risks seriously; new analytical tools render climate risks understandable; a collaborative model for addressing risks exists; and there is value to proactive action. Recognition of and management of these risks

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[74] Columbia Law School, (2014, February). Center for Climate Change Law Helps Secure Novel Pact with Con Edison. Retrieved at: https://www.law.columbia.edu/media_inquiries/news_events/2014/february2014/Con-Ed-climate-change-measures.

[75] Zamuda, C., et al. (2018). Energy Supply, Delivery, and Demand in *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II*. U.S. Global Change Research Program, pp. 174-201. Doi: 10.7930/NCA4.2018.CH4.

[76] United Nations Principles of Responsible Investment (2019, November). Fiduciary Duty in the 21st Century Final Report. Retrieved at: https://www.unpri.org/fiduciary-duty-in-the-21st-century-final-report/4998.article#.Xc0f5YqtBhQ.twitter.

will transform how utilities assess prudent planning and operations. These developments also mean that firms and regulators now have the tools to act.

Q. What materials have you reviewed in preparation of this testimony?

A. We reviewed literature from the following categories to inform this testimony:

- Duke Energy Carolinas and Duke Energy Corporation statements on climate change and climate-related risks;
- Decisions by North Carolina policymakers that might inform future climate-related regulatory risk;
- Financial institution discussion and business decisions on climate-related risks;
- Guidance from financial advisory organizations on prudent business practice around disclosing and managing climate-related risks;
- Research assessing the nature of climate-related risks and best practices on avoiding them from top research organizations;
- Case studies of other electric utilities and utilities commissions weighing their own response to climate-related risks.

In total, our review spanned 130 sources from 97 organizations. While the review presented here is not exhaustive or universal, the documents assembled paint a clear picture of the state of climate-related risks and the institutional response to them. A list of sources consulted during the literature review is available in Exhibit JMV-TF-5.

B. Physical Risks

Q. Please define climate-related physical risks and describe how they are expected to impact the electric utility industry.

A. Climate-related physical risks are risks to assets or operations due to physical phenomena impacted by climate change. These physical changes can manifest as rising sea levels and flood risk, increasing ambient temperatures and heat waves, changing precipitation patterns, and/or increasing frequency and intensity of extreme weather events. Just as weather and climate have always affected the day-to-day operations and long-term planning of electric utilities, the industry is already affected by the changing climate at the generation, transmission, and distribution levels.[77]

Climate change impacts that will have the most substantial risk implications for the electric industry are listed below.

- **Extreme Weather Events:** More frequent and severe but less predictable storms (and, in coastal areas, attendant storm surges) will result in damage to infrastructure and increases in storm damages. Ratepayers are likely to see decreased reliability and the potential for long outages.
- **Increased Temperatures:** Increased ambient temperatures will reduce performance and reliability of electricity infrastructure.[78] Customer demand is

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[77] Zamuda, C., et al.
[78] Bertolotti et al., p. 5.

projected to increase as cooling loads increase, but become less predictable.[79] Longer, more intense heat waves present health risks for utility workers. High temperature and high cooling load will present sustained stress to the grid.[80]

- **Changes in Precipitation:** Although not necessarily applicable to the Company's service territory, projected precipitation patterns as a result of climate change are likely to lead to drier conditions in the southern and western parts of the United States, with intermittent episodes of heavy precipitation.[81] A lack of steady water supply could severely impede the operation of nuclear and conventional thermal plants, which rely on an available stream of water for cooling.[82] Droughts may also increase the risk of wildfire, with clear and present implications for utilities' transmission & distribution.[83]
- **Sea-level Rise and Flooding:** Especially in combination with extreme weather events, higher sea levels increase the risk of inundation for coastal assets.[84]

While electricity infrastructure is designed to withstand a range of conditions, future conditions are projected to reach outside of historical ranges. Understanding and planning for future conditions, and not just relying on historical

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[79] ConEdison (2019, December). Climate Change Vulnerability Study. p. 12. Retrieved at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.
[80] Larsen, K., Larsen, J., Delgado, M., Herndon, W., Mohan, S, (2017, January) Assessing the Effect of Rising Temperatures: The Cost of Climate Change to the U.S. Power Sector. Rhodium Group, p. 10-19. Retrieved at https://rhg.com/wp-content/uploads/2017/01/RHG_PowerSectorImpactsOfClimateChange_Jan2017-1.pdf.
[81] Nanavati, P., & Gundlach, J., (2016, September), The Electric Grid and its Regulators—FERC and State Public Utility Commissions. Sabin Center for Climate Change Law at Columbia Law School, p. 14.
[82] *Ibid.,* p. 15.
[83] Bertolotti et al, p. 4.
[84] Nanavati & Gundlach, pp. 19.

benchmarks, is becoming necessary to avoid premature asset replacement and stranded assets.[85,86]

Analysts estimate that these damages will add up for electric utilities. In a review of the financial materiality of climate-related physical risks to electric utilities, BlackRock Investment Institute placed the increased frequency and severity of hurricanes as a "10" on a 1-10 scale.[87] Another estimate found that storm damages were, on average, likely to increase by 23 percent to $1.7 billion per year by 2050.[88] Analysis is increasingly capable of looking at plant-level climate risks.[89]

Insurers are increasingly exposed to risks of concurrent payments as the incidence of climate-related events grows,. After California's 2018 climate-related[90] wildfire season, which included over 13,000 homes and businesses

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[85] Chung, J., (2020, January). *Ameren, Xcel, Dominion, Duke among most at-risk from changing climate: Moody's* (interview by Catherine Morehouse for Utility Dive).
[86] Kunkel, K., & Easterling, D., (2020, January). North Carolina Climate Science Report. Presentation given to North Carolina Climate Change Interagency Council, p. 33. Retrieved at https://files.nc.gov/ncdeq/climate-change/interagency-council/Jan-22-2020--Interagency-Climate-Council-presentation-rev.pdf.
[87] BlackRock, (2019, April), Getting Physical: Scenario Analysis for Assessing Climate-Related Risks. p.17. Retrieved at https://www.blackrock.com/us/individual/literature/whitepaper/bii-physical-climate-risks-april-2019.pdf.
[88] Brody, S., Rogers, M., Siccardo, G., (2019, April), Why, and how, utilities should start to manage climate-change risk. McKinsey & Company, p. 3. Retrieved at: https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/why-and-how-utilities-should-start-to-manage-climate-change-risk.
[89] Bertolotti, et al.
[90] Shrimali, G. (2019, October). In California, More than 340,000 Lose Wildfire Insurance. *High Country News.* Retrieved at https://www.hcn.org/articles/wildfire-in-california-more-than-340000-lose-wildfire-insurance.

destroyed and 46,000 insurance claims,[91] analysts were concerned that California utilities might be "uninsurable."[92]

Q. How will climate-related physical risks affect the Company specifically?

A. The Company's placement in North Carolina is determinative of its exposure to climate-related risks. Although all utilities will be subject to the risks above, Southeast utilities are particularly exposed to more frequent and severe storms and hurricanes.[93]

High-quality, in-depth studies of climate impacts in North Carolina specifically are in progress. As directed by Section 9 of Governor Roy Cooper's Executive Order 80, leading North Carolina institutions are developing a North Carolina Climate Science Report that assesses the state of the science and makes projections for North-Carolina-specific impacts.[94] Preliminary findings from the report indicate that, "[l]arge changes in North Carolina's climate—much larger than at any time in the state's history—are ***very likely*** by the end of this century under both the lower and higher [emissions] scenarios."[95] Authors of the report presenting to the North Carolina Climate Change Interagency Council found it is

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[91] Bernstein, S., & Barlyn, S., (2019, January). Insurance losses for California Wildfires top $11.4 Billion. *Reuters*. Retrieved at https://www.reuters.com/article/us-california-fire-claims/insurance-losses-for-california-wildfires-top-114-billion-idUSKCN1PM2CF.
[92] Jaffe, A., Busby, J., Blackburn, J., Copeland, C., Law, S., Ogden, J., & Griffin, P., (2019, September). Impact of Climate Risk on the Energy System. *Council on Foreign Relations.* Retrieved at https://cdn.cfr.org/sites/default/files/report_pdf/Impact%20of%20Climate%20Risk%20on%20the%20Energy%20System_0.pdf.
[93] Zamuda, C., et al.
[94] North Carolina Department of Environmental Quality, (2019). NC Climate Science Report Development. Retrieved at https://deq.nc.gov/nc-climate-science-report-development.
[95] Kunkel, K., & Easterling, D., (2020, January).

"***very likely*** [90-100% probability]" that NC temperatures will increase in all seasons, extreme precipitation frequency and intensity will increase, and that heavy precipitations accompanying hurricanes passing over North Carolina will increase. As a result, climate design standards for North Carolina infrastructure will be outdated by the middle of this century[96]—likely within the design lifetime of investments proposed under the Grid Improvement Plan. The North Carolina Climate Risk Assessment and Resiliency Plan is moving through a rigorous peer review process and will be finalized and submitted to the Governor by March 1, 2020.[97]

Financial observers have already been paying careful attention to utilities' climate-related physical risks. When S&P announced a negative outlook for Duke Energy Corporation in 2019, it noted that "[t]he company also operates its utilities in regions of the U.S. that are prone to frequent hurricanes, which could increase the company's risk exposure because climate change is intensifying the severity and frequency of these natural disasters globally."[98] Moody's and S&P mentioned hurricanes or named storms in ratings of the Company in each year 2017-2019.[99]

Beyond broad characterizations, credit rating agencies are using increasingly powerful analytical methods for understanding climate risks, finding

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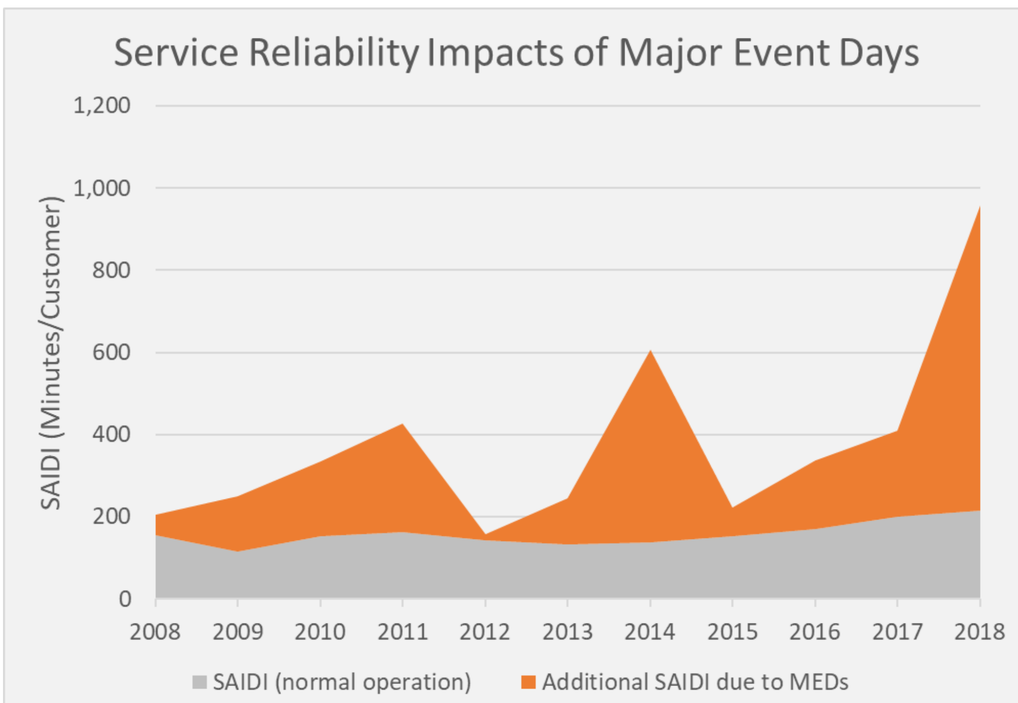
[96] *Ibid.*
[97] North Carolina Executive Order 80.
[98] S&P Global Ratings, (2019, May), Research Update: Duke Energy Corp. and Subs. Outlook Revised To Negative On Coal Ash Risks, Regulatory-Lag, And Project Delays. P. 4. Retrieved at Company Response to Public Staff Data Request 38-5.
[99] Company Response to Public Staff Data Request 38-5.

Duke Energy's footprint in the Carolinas as exposed to climate-related risks. Moody's published their first review of climate-related risks for electric utilities in January 2020 and found Duke Energy a top risk for hurricane threats.[100]

Company materials submitted in this proceeding validate the reported Moody's findings. Figure 2 below disaggregates system average interruption duration index (SAIDI) in regular operation and during Major Event Days, which include but are not exclusively related to weather events.

Figure 2: Duke Energy Carolinas System Average Interruption Duration Index (SAIDI) with and without Major Event Days (MEDs)[101]



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[100] Morehouse, 2020.
[101] Graph compiled using MED and non-MED SAIDI figures from Company Response to the North Carolina Sustainable Energy Association ("NCSEA") Data Request 2-8.

The Company's SAIDI trend over the last ten years shows a relatively flat SAIDI during normal operations, but increasing SAIDI impacts from major event days. While the major event days' occurrence is inherently stochastic, experts have found a statistically significant increase in major event days over time.[102] For context, the average customer was without power for 250 minutes in 2018,[103] and the cumulative improvement projected for phase one of the Grid Improvement Plan will reduce SAIDI by 28.24 minutes per customer.[104]

C. Financial Risks

Q. Please define climate-related financial risks and summarize how they are expected to impact the electric utilities industry.

A. Climate-related financial risks refer to impacts on access to reliable and affordable financing a firm might face due to climate change and the financial community's response to it. Financial risks can be difficult to disaggregate from other risks, because financial institutions' climate-related reasons for up- or down-grading a firm will often be linked to other climate-related impacts (e.g. downgrading a California utility due to exposure to wildfire risks). But the unique impacts of financial actions, and specific pathways by which these risks are expressed (e.g.

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[102] Larsen, P., Sweeney, P., Hamachi-LaCommare, K., Eto, J., (2014, April). Exploring the Reliability of U.S Electric Utilities. Lawrence Berkeley National Laboratory, p. 29. Retrieved at http://www.usaee.org/usaee2014/submissions/OnlineProceedings/IAEE_ConferencePaper_01Apr2014.pdf.
[103] US Energy Information Administration ("EIA"), (2018, April), "Average frequency and duration of electric distribution outages vary by states." Retrieved at https://www.eia.gov/todayinenergy/detail.php?id=35652.
[104] Company response to Public Staff Data Request 36-5.

downgrades, disinvestment, votes against board members, changes to stock price), merit treating financial risks as a separate category.

Investors are already paying special attention to electric utilities and their responses to climate-related risks. The Climate Action 100+, a global group of investors with over $35 trillion under management, identified 32 electric utilities as part of the hundred largest greenhouse gas emitters in the world.[105] Duke Energy Corporation is listed as one of Climate Action 100+'s focus companies.

Credit ratings agencies have already integrated review of climate-risk, as a part of environmental, social, and governance ("ESG") review, into their credit ratings. S&P found in its lookback over ratings published 2015-2017 that environment and climate ("E&C") risks played an important role in over 700 cases, and over 100 listed E&C risks as a key factor. Of cases where E&C risks were a key factor, over 40% resulted in downgrades.[106] At the same time, S&P demonstrates an opportunity to prudent energy & climate risk management—20 upgrades listed E&C issues as a key factor.[107]

Investors like BlackRock and Morgan Stanley are also building analytical capacity to understand the distribution of climate-related risks. BlackRock and the Rhodium Group are using their plant-level climate risk findings to generate

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[105] Climate Action 100+, (2019). *2019 Progress Report.* Retrieved at https://climateaction100.files.wordpress.com/2019/10/progressreport2019.pdf.
[106] Williams, J., & Wilkins, M., (2017, November), How Environmental And Climate Risks And Opportunities Factor Into Global Corporate Ratings – An Update. *S&P Global Ratings*. Retrieved at Company Response to Vote Solar Data Request 5-2.
[107] *Ibid.*

company-level climate-risk indices.[108] Using those indices, they find that climate-resilient utilities trade at a slight premium, while the most risk-exposed utilities trade at a discount.[109] An academic analysis of the relationship between climate risk, risk management, and financial health found similar results:

> "We document a positive correlation between cost of debt and carbon risk for firms [without awareness of climate risks]. Further, this association is economically meaningful, with a one standard deviation increase in carbon risk mapping into between a 38 and 62 basis point increase in the cost of debt. Equally, we find that the penalty is effectively negated for firms exhibiting carbon risk awareness."[110]

Q. How might climate-related financial risks affect the Company specifically?

A. Duke Energy Corporation's largest individual shareholders have taken strong positions on risks related to climate change and their likely response. Table 1 below demonstrates a selection of Duke Energy's creditors and their position on climate risks.

Table 1: Selection of Duke Energy Investors and Positions on Climate Risk

Shareholder	% Share of DUK	Climate-related Risk Position
Vanguard Group	8.19%*	"Many companies remain far beyond on their [climate-related risk] journey and have room to improve their disclosure and better educate their board on climate-related risks."[111]

[108] Bertolotti et al.
[109] BlackRock, 2019.
[110] Jung, J., Herbohn, K., Clarkson, P., (2018, July), "Carbon Risk, Carbon Risk Awareness, and the Cost of Debt Financing." *Journal of Business Ethics.*
[111] Vanguard (2019). Investment Stewardship 2019 Annual Report.

Blackrock Fund Advisors	5.3%*	"In absence of robust disclosures, investors, including BlackRock, will increasingly conclude that companies are not adequately managing risk."[112]
State Street Advisors	5.15%*	"The vast majority of companies are taking a short-term, tactical approach to climate risk; they are failing to identify the long-term threats and opportunities created by a shift to a low-carbon economy and to incorporate this thinking into their boards' strategic planning."[113] Sent a letter to boards (January 2020) advising they would "take appropriate voting action" against board members of major US firms if they rated poorly on SSGA's ESG score and did not articulate how they would improve it.[114]
New York City Employees' Retirement System	**	Sent a letter to Duke Energy advocating for an ambitious climate goal. "This initiative makes clear that mobilizing for the planet goes hand-in-hand with protecting our pensions, and we need these commitments now."[115]

*: Top three individual investors
**: Investment share outside of top 10 are not published.

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[112] Fink, 2020.

[113] State Street Global Advisors, (2019, June), Climate-Related Disclosures in Oil and Gas, Mining, and Utilities: The Current State and Opportunities for Improvement. Retrieved at https://www.ssga.com/investment-topics/environmental-social-governance/2019/06/climate-disclosure-assesment.pdf.

[114] Wigglesworth, R., (2020, January), "State Street vows to turn up the heat on ESG standards." *Financial Times*. Retrieved at https://www.ft.com/content/cb1e2684-4152-11ea-a047-eae9bd51ceba.

[115] Kerber, R., (2019, February), "Big U.S. pension funds ask electric utilities for de-carbonization plans." *Reuters*. Retrieved at https://www.reuters.com/article/us-usa-utilities-investors/big-u-s-pension-funds-ask-electric-utilities-for-decarbonization-plans-idUSKCN1QH27D.

Credit rating agencies Moody's and S&P mention climate-related physical, regulatory, and economic risks in their updates on the Company and Duke Energy Corporation.[116] In and of themselves, the risks recorded in these updates may have negative impacts on the Company's business operations. But the financial community's awareness of these risks, and its potential reaction to those risks through stock price movement, shareholder action, and changes to credit ratings, present a unique challenge to the Company's business risks.

D. Economic Risks

Q. Please define climate-related economic risks and summarize how they are expected to impact the electric utilities industry.

A. Climate-related economic risks are divided into technology risks and market risk. Technology risks refer to exposure of a firm's assets and operations from disruptive or innovative technologies that develop and mature through societal responses to climate change. In the electric utility sector, the principal technology risk is that of low- or no-carbon generation technologies like wind and solar displacing conventional generation and therefore "stranding" those assets' ability to recover their capital investment. As an example, NIPSCO and Tri-State recently recognized and corrected for climate-related technology risk by committing to shut down

[116] Company Response to Public Staff Data Request 38-5.

legacy coal assets in favor of a shift to renewables.[117,118] Analyses sponsored by both companies demonstrate the prudency of this decision: it will save money for these companies and ultimately for ratepayers.

Market risk refers generally to risks created by markets adapting to climate change. These risks are subtle and complex, especially in the energy sector, but one illustration might be customers opting out of typical utility service to pursue renewable options. Because of this complexity, this testimony will not analyze or evaluate market risks.

Analysts have focused particular attention on technology risks and opportunities for utilities operating legacy coal assets. One analysis by Energy Innovation found that by 2025, new wind and solar would be less expensive than running 70% of all coal assets in the United States.[119] Subsequent studies from Morgan Stanley and Moody's have corroborated those results.[120]

The same principle applies to gas generation. A study from the Rocky Mountain Institute found that a portfolio of clean energy technologies would deliver

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[117] McMahon, J., (2019, July), "In Conservative Indiana, Utility Chooses Renewables Over Gas As It Retires Coal Early." *Forbes*. Retrieved at: https://www.forbes.com/sites/jeffmcmahon/2019/07/02/mike-pences-indiana-chooses-renewables-over-gas-as-it-retires-coal-early/#7cb3265243b4.

[118] Best, A., (2020, January), "Tri-State CEO says wholesaler's clean energy transition will pay dividends." *Energy News Network.* Retrieved at: https://energynews.us/2020/01/21/west/tri-state-ceo-says-wholesalers-clean-energy-transition-will-pay-dividends/.

[119] Gimon, E., O'Boyle, M., Clack, Ct., McKee, S., (2019, March), The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources. *Energy Innovation* and *Vibrant Clean Energy*. Retrieved at https://energyinnovation.org/wp-content/uploads/2019/03/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL.pdf.

[120] Smyth, J., (2019, December), "Financial analysts expect decarbonization will benefit utility ratepayers and shareholders." *Energy and Policy Institute.* Retrieved at: https://www.energyandpolicy.org/financial-analysts-expect-decarbonization-will-benefit-utility-ratepayers-and-shareholders/.

the same energy at a lower cost than 90% of gas-fired power plant capacity. The report ends with a recommendation to state utility regulators: "[a]ccount for the significant risk that uneconomic gas generation will increase customer rates."[121]

Q. How might climate-related economic risks affect the Company specifically?

A. The same national trends identified regarding coal and gas assets also play out in North Carolina. For coal assets, "[t]he trend is so strong that it is hard to imagine Southeastern utilities not relying heavily on solar and complementary load shifting resources to replace the coal and save customers money."[122]

In many cases, multiple climate-related trends can come together to cause an economic shift—a shift that the Company is already acknowledging. In describing the forces that led to the Company's decision to retire several coal plants, the Company cites the following trends:

- On-going price declines and efficiency improvements of potential replacement including CTs, renewables and energy storage alternatives;
- Potential for increasing regulatory drivers including the release of the NC DEQ Climate Plan, NC Executive Order 80, and NCUC 2018 IRP Order requiring evaluation of accelerated coal plant retirements in future IRPs; and

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[121] Teplin, C., Dyson, M., Engel, A., Glazer, G., (2019), The Growing Market for Clean Energy Portfolios: Economic Opportunities for a Shift from New Gas-Fired Generation to Clean Energy Across the United States Electricity Industry. *Rocky Mountain Institute*, https://rmi.org/cep-reports.
[122] Gimon, et al.

- Potential for federal or state CO_2 legislation.[123]

Credit rating analysts are paying special attention to the Company's climate-related economic risks. Moody's 2019 credit rating for the Company found that "[DEC] has a moderate carbon transition risk within the regulated utility sector because, as an integrated utility, its generation ownership places it at a higher risk profile than transmission and distribution companies."[124]

Informally, Duke Energy Corporation officials have responded to the prospect of gas generation being outcompeted by renewables or inconsistent with a carbon goal by floating shorter depreciation periods as short as 15 years for new gas generation.[125] The necessary result of a shorter operating life, however, is faster recovery of capital investment, driving higher annual costs and a higher average cost per kilowatt-hour. Duke Energy's potential decision to accelerate depreciation and increase ratepayer costs for these plants is, itself, an example of climate-related risks increasing costs for ratepayers. These higher costs also increase the likelihood that renewables might be a more cost-effective option.

The risks of distributed generation referred to in Witness Hevert's testimony are examples of technology risk.[126] Hevert's testimony does not, however, address the Company's reduced exposure to climate-related risks as renewables come onto

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[123] Company Response to Tech Customers Data Request 3-26.
[124] Moody's Investor Service, (2019, October), "Duke Energy Carolinas, LLC." Retrieved at Company's First Supplemental Response to Public Staff Data Request 38-5.
[125] Morehouse, C., (2019, October), Duke VP likens gas plant buildout strategy to 15-year home mortgage on path to zero carbon." *Utility Dive*. Retrieved at https://www.utilitydive.com/news/duke-vp-likens-gas-plant-buildout-strategy-to-15-year-home-mortgage-on-path/565328/.
[126] Hevert Direct,

the grid, or the potential of customer-owned distributed generation to reduce exposure to climate risks and future carbon pricing. It is clear that distributed energy resources offer resilience benefits, and actors at the state and federal level are developing increasingly precise methods for valuing resiliency.[127]

E. Regulatory Risks

Q. Please define climate-related regulatory risks and summarize how they are expected to impact the electric utilities industry.

A. Climate-related regulatory risks refer to negative impacts on a given firm due to policy changes that either seek to constrain actions that would exacerbate climate change, or incentivize actions that would ameliorate its impacts. Given the greenhouse gas emissions that have until recently been an inextricable part of the electric utility industry, the clearest regulatory risk to electric utilities is constraints on emissions or requirements to procure energy from renewable sources.

The United Nations Principles for Responsible Investment (UNPRI) uses a framework called the Inevitable Policy Response (IPR) to understand regulatory risk. This framework uses a more probabilistic model of climate policy: Instead of using a scenario-based "climate policy" and "no climate policy" approach, IPR asks when such a policy might be put in place. Using this framework, UNPRI found that a two-degree policy scenario would on average lead to a 4% decrease in valuation

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[127] National Association of Regulatory Utility Commissioners, (2019, April). The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices. Retrieved at: https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

for electric utilities. It also found electric utilities to have the widest variation in valuation adjustment by firm (some firms decreasing in valuation by over 30%, and others increasing by the same margin) of any sector analyzed.[128]

Financial observers are paying close attention to firms' policy, legal, and regulatory risks and their prudent management. S&P's lookback on the role of environment & climate factors in their credit ratings found that physical risks were the most cited type of risk, but policy risks were a close second—and the two of them were drivers of S&P rating decisions more than all other listed climate-related risks and opportunities combined.[129]

Q. How might climate-related regulatory risks affect the company specifically?

A. Regulation of greenhouse gas emissions at the state or federal level would directly impact the Company's operations and planning. As the single largest owner of coal and gas generation capacity in 2018[130] and largest carbon emitter in the nation among electric power producers in 2019,[131] Duke Energy Corporation would likely face a substantial regulatory burden from passage at any level. The share of generation capacity served by conventional generation (coal and gas) for the Company is approximately 50%, and according to its integrated resource plan that

[128] UN Principles for Responsible Investment (2019), Impacts of the Inevitable Policy Response on Equity Markets. Retrieved at https://www.unpri.org/download?ac=9857.
[129] Williams & Wilkins.
[130] Dholakia, G., (2019, December). Duke Energy tops operating US coal, gas capacity ownership. *S&P Global.* Retrieved at: https://www.spglobal.com/marketintelligence/en/news-insights/trending/w4jueneo16bxoihgp-fhya2.
[131] Van Atten, C., Saha, A., Hellgren, L., Langlois, T, (2019, June), Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States. *MJ Bradley.* Retrieved at https://www.mjbradley.com/sites/default/files/Presentation_of_Results_2019.pdf.

figure would not decrease through 2034 (although the share of conventional generation will shift from coal to gas).[132]

Speculating on the likelihood of a federal climate policy is outside of the scope of this testimony, but recent developments at the state level, as discussed more in-depth in Section 4, set the stage for an increasing level of ambition regarding greenhouse gas policy.

Preparation for uncertain outcomes is key to risk management and particularly apt for understanding regulatory risks. The Company, for example, already orients its planning around a tax on emissions beginning in 2025.[133] The level of tax used in the Company's planning starts at one-eighth the level of the tax proposed in September 2019 by the Climate Leadership Council, which counts Exelon, ExxonMobil, BP, Shell, and Vistra as members.[134]

F. Reputational Risks

Q. Please define climate-related reputational risks and summarize how they are expected to impact the electric utilities industry.

A. Climate-related reputational risks represent those tied to "changing customer or community perceptions of an organization's contribution to or detraction from the transition to a lower-carbon economy."[135] Electric utilities risk damage to their reputation if their response to climate change is out of line with stakeholders'

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[132] Duke Energy Carolinas (2019, September), Integrated Resource Plan: Update Report. pp. 9, Chart 2-A. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=40bbb323-936d-4f06-b0ba-7b7683a136de.
[133] Company Response to Vote Solar Data Request 3-13.
[134] Climate Leadership Council (2019, September). Our Plan. Retrieved at https://clcouncil.org/our-plan/.
[135] TCFD Recommendations, p. 6.

expectations, from inadequate storm repair to continued investment in conventional electric generation technology without emissions controls.

Increasingly, electric utilities are managing their reputational risk by making commitments or announcements to decrease their greenhouse gas emissions. These announcements may increase goodwill, and potentially decrease the likelihood of new regulatory regimes that might mandate a decrease in emissions. At the same time, announcements in and of themselves introduce reputational risks if firms do not appear to be honoring their public commitments.

Q. How might climate-related reputational risks affect the Company specifically?

A. A recent poll found North Carolina voters favor action to reduce carbon emissions,[136] and Duke Energy Corporation's recent shareholder resolutions show similar sentiment among the Company's shareholders.[137] As long as the Company's operations emit carbon, it will likely be exposed to reputational risks. The Company also faces scrutiny due to ongoing coal ash remediation issues.[138]

Duke Energy Corporation announced its non-binding net-zero-by-2050 goal on September 17, 2019, establishing its presence in a growing cohort of large utility holding companies with ambitious carbon goals.[139] As discussed above,

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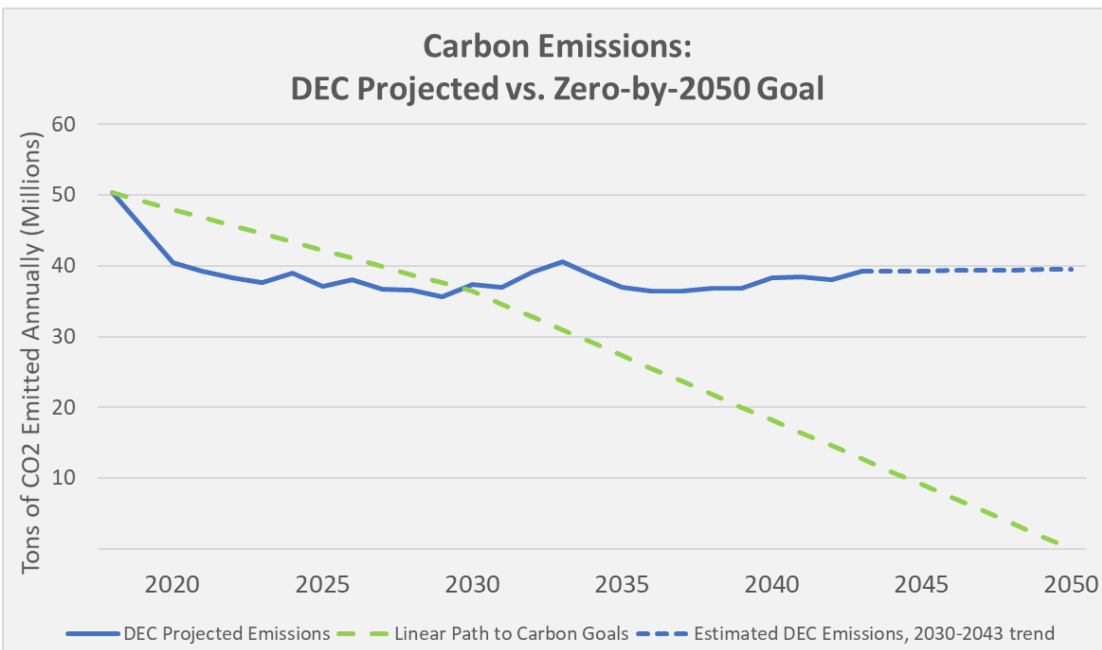
[136] Global Strategy Group (2019, October). Regulating North Carolina's Carbon Pollution: Research Findings Prepared by Global Strategy Group for EDF Action. P. 6. Retrieved at https://www.edfaction.org/sites/edactionfund.org/files/u141/nc_carbon_limits_survey_analysis.pdf.
[137] Duke Energy (2019). Shareholder Proposals. Retrieved at: https://www.duke-energy.com/proxy/_/media/pdfs/our-company/investors/proxy/shareholder-proposal.pdf?la=en.
[138] Sorg, L. (2020, January). DEQ, Duke Energy, community groups strike deal on largest coal ash cleanup in US. *NC Policy Watch.* Retrieved at: http://www.ncpolicywatch.com/2020/01/02/deq-duke-energy-community-groups-strike-deal-on-largest-coal-ash-cleanup-in-us/.
[139] Gearino, D.

carbon announcements such as this one mitigate some reputational risks but exacerbate others. Although the Corporation's goal is enterprise-wide, the Company would presumably need to follow a similar emissions path for the Corporation to meet its goals. However, the Company's projections in this case do not show that the Company will achieve them. Figure 3 shows the Company's projected carbon emissions as consistent with the IRP approach, in millions of tons of CO2 emitted annually, compared to the emissions pathway needed to achieve the Corporation's goals for DEC.

Figure 3: DEC Projected Emissions versus Pathway Consistent with Corporate Goals[140]



[140] Graph compiled using projected annual CO2 emissions from Company response to Vote Solar Data Request 3-13 and Duke Energy Corporation's September 17, 2019 net-zero carbon emissions announcement.

Thus, the emissions projected for purposes of this case do not comply with stated goals. Worse, these projected carbon emissions are used to determine the value of carbon reductions created by the Grid Improvement Plan in the Company's cost-benefit analyses.[141] The result of these two decisions is that the Grid Improvement Plan's cost-benefit analysis is 'taking credit' for carbon reduction that would not occur if the Company followed a path to achieving their carbon goal. The clear disconnect between the Corporation's public communications and the Company's statements in this proceeding represents a substantial reputational risk.

G. Commission Consideration of Climate Risk

Q. Based on your review of the literature and financial statements, do you conclude that these risks are material?

A. Based on a review of the available literature, the Company's filings, and the findings shown above, we assess climate-related risks are material to any electric utility's investments, costs, and operations, and they are specifically material to the Company in this proceeding.

Q. Does this testimony represent a comprehensive evaluation of the company's vulnerability to climate risks?

A. No. A comprehensive assessment of the Company's climate-related risks and the opportunities available in addressing those risks would require more operational data than is available to the public, consensus from a range of stakeholders, and a

[141] Oliver Direct, Ex. 7.

substantial analytical burden. The New York Storm Hardening & Resiliency Collaborative and Con Edison's Climate Change Vulnerability Study represent best practices in the climate-related risk field.

Q. How might the Commission view the TCFD climate-related risk framework?

A. As a regulator, the Commission has an important role to play in ensuring emergent risks are managed. (In fact, World Bank case studies on utility climate adaptation find that regulatory support is invaluable in incenting firms to act on long-term risks.)[142] At a minimum, the Commission may want to ensure that firms it regulates are aware of these risks and that the expectations of management are clear. The Commission could then support firms in meeting those expectations through information sharing and regulatory innovation. The Commission could use the TCFD framework as a tool-kit for categorizing risks and setting expectations for prudent management.

Q. In your view, is the management of climate-related risks a critical component for keeping rates low for customers?

A. Yes. Managing climate-related risks is and will be integral to minimizing the costs imposed on customers associated with the impacts of climate change and ensuring the provision of safe and adequate utility service. Like any other business risk, the

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[142] Audinet, P. (2014). Climate Risk Management Approaches in the Electricity Sector. *World Bank Group*. Retrieved at https://climate-adapt.eea.europa.eu/metadata/publications/climate-risk-management-approaches-in-the-electricity-sector-lessons-from-early-adapters.

prudent management of climate risk will minimize those cost to the Company and, therefore, to customers.

Unlike other risks, however, customers are also directly exposed to climate-related risks. Proactive action is necessary to ensure that customers are best protected from climate-related risks and that they get reliable service when they need it most. Managing climate-related risks is in the interest of the Company and the public, a proposition the Company seems to accept based on its discovery responses.[143]

Q. If the Commission or the Company adopted the climate-related risk framework, would the Company be expected to undertake major changes in its operations immediately?

A. No. Climate-related risks would represent an additional input to the Company's existing decision-making process. Decision-makers at the Company, and the associated oversight by regulators, would still weigh risks and opportunities across multiple dimensions when making business decisions.

Q. Do climate-related risks justify an increase to the Company's evaluation of its return on equity?

A. No. First, climate-related risks may be described as "asymmetrical" risks—that is, prudent management may avoid a loss of return on equity, but is less likely to secure a higher return on equity. Experts at the Brattle Group have noted that these risks

[143] Company Response to the Center for Biological Diversity & Appalachian Voices ("CBD & AV") Data Requests 2-34.

are not suitable for addressing through a simple risk premium.[144] Second, exposure of the Company to these risks is at least partially dependent on the actions it takes in the operation and planning of its enterprise. Therefore, the risk for the Company is only present to the extent that it pursues business decisions that ignore that risk. The same experts at the Brattle group note that "It often may be easier to mitigate a risk directly rather than to measure its marginal effect on the cost of capital."[145] The California Public Utilities Commission addressed a similar issue with regard to wildfire risk and concluded: "The standard set in *Bluefield* and *Hope* is that investor-owned utilities should not be rewarded with an ROE that is inflated due to imprudent actions."[146]

H. Emerging Best Practices for Managing Climate-Related Risks

Q. Based on your review of the climate-related risk literature, have you identified best practices for managing climate-related risks?

A. Yes. The Task Force for Climate-Related Financial Disclosures recommends that firms exposed to climate-related risks and opportunities embed their climate strategy into the core of their business practices, then disclose how they do so to investors. TCFD recommends that accountability for climate strategy be embedded into the firm's board and management governance structure; that the firm's strategy

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[144] Brattle Group, (2017), Compensating Risk in Evolving Utility Business Models. Pp. 14. Retrieved at https://brattlefiles.blob.core.windows.net/files/7264_compensating_risk_in_evolving_utility_business_models_august_2017.pdf.
[145] Ibid., p. 16.
[146] California Public Utilities Commission, (2019, December). Decision on Test Year 2020 Cost of Capital for the Major Energy Companies. Application 19-04-014 et al. p. 36 (italics added). Retrieved at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M322/K633/322633896.PDF.

at all levels be informed by climate risks and scenario-based planning around accelerated transitions; that risk management at all levels integrate climate-related risks; and that the firm's reported metrics and targets include exposure to climate risks and total carbon emissions.[147] As a non-financial sector with special exposure to physical and transition risks, TCFD recommends additional disclosures for electric utilities, including disclosure of internal carbon prices and capital expenditures on low-carbon generation assets.[148]

Q. Do climate-related risks only apply to the Company's generation assets?

A. No. In fact, climate-related risks span the whole of the Company's operations, from generation to consumer programs. Investments within the Grid Improvement Plan, for instance, are subject to climate-related physical risks (as we describe in Section 5). To the extent that the Grid Improvement Plan enables a transition to a de-carbonized and resilient grid, the investments also have implications for the Company's financial, economic, regulatory, and reputational risks.

Q. How have electric utilities responded to the onset of climate-related physical risks?

[147] Task Force on Climate-Related Financial Disclosures, (2017). Final Report: Recommendations of the Task Force on Climate-Related Financial Disclosures. Retrieved at: https://www.fsb-tcfd.org/wp-content/uploads/2017/06/FINAL-2017-TCFD-Report-11052018.pdf.

[148] Task Force on Climate-Related Financial Disclosures, (2017). Implementing the Recommendations of the Task Force on Cliamte-Related Financial Disclosures. Retrieved at: https://www.fsb-tcfd.org/wp-content/uploads/2017/12/FINAL-TCFD-Annex-Amended-121517.pdf.

A. Even as early as 2014, electric utilities understood the need for guidance and recommendations on resilience to climate-related physical risks ,[149] and in 2015 the US Department of Energy convened the *Partnership for Energy Sector Climate Resilience*, a collaborative of 19 electric utilities supported by DOE in developing best practices for understanding climate-related vulnerabilities and establishing climate resilience.[150]

The partnership's *Guide for Climate Change Resilience Planning* describes a two-step process for resiliency. First, utilities should conduct a vulnerability assessment to understand their exposure and sensitivity to climate risks. Second, with the vulnerability assessment as an input, utilities can create a resilience plan that responds to those identified vulnerabilities, reviewing a wide range of resilience measures and using a systematic cost-benefit methodology that includes appropriate co-benefits.[151] This two-step process ensures that resiliency measures are designed with granular, up-to-date, high-quality information on vulnerabilities; use of a systematic cost-benefit analysis ensures that all resilience measures are fairly evaluated.

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[149] Edison Electric Institute, (2014, March). *Before and After the Storm: A compilation of recent studies, programs, and policies related to storm hardening and resiliency.* Retrieved at https://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/BeforeandAftertheStorm.pdf.

[150] US Department of Energy, (2016, September). *Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning.* Retrieved at: https://toolkit.climate.gov/sites/default/files/Climate%20Change%20and%20the%20Electricity%20Sector%20Guide%20for%20Climate%20Change%20Resilience%20Planning%20September%202016_0.pdf.

[151] *Ibid., p. 71.*

Q. Are there any examples or case studies of climate-informed planning best practices being implemented?

A. Yes. The work of the New York Storm Hardening & Resiliency Collaborative (consisting of Con Edison, Department of Public Service Staff, the City of New York, several environmental NGOs, and others) that emerged out of a settlement in Con Edison's 2013 rate case represents a best practice in the industry. In its order approving Con Edison and public staff's settlement the New York Public Service Commission found that "The Con Edison Resiliency Collaborative has provided a valuable focus for innovative approaches to the 21st century challenges to the utility system, and its work should continue, in public where appropriate."[152] The Collaborative reviewed Con Edison's proposed storm hardening investments, and also created a framework for climate vulnerability assessment, examined the applicability of non-wires resiliency strategies, and developed a robust cost-benefit analysis.[153]

Con Edison's complete climate risk vulnerability study was published in December 2019. The vulnerability study presents a comprehensive, forward-looking assessment of physical risks of climate change (including, for example, risks to workers due to higher frequency and intensity of heat waves) through an

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[152] Case 13-E-0030 *et al.;* Con Edison's Electric, Gas, and Stream Rates -- Order Approving Electric, Gas, and Steam Rate Plans in Accord with Joint Proposal (2014, February). State of New York Public Service Commission. Retrieved at: https://climate.law.columbia.edu/sites/default/files/content/docs/Final-Order-2014-02-21%20(1).pdf.

[153] Case 13-E-0030 *et al,:* Consolidated Edison Company of New York, Storm Hardening and Resiliency Collaborative Phase Three Report. (2015, September).

integrated framework of physical climate impacts, risks to assets and operations, and potential resilient solutions.[154] The study's use of the best available climate science—analyzed through a transparent, risk-based approach and considering a wide range of resilience solutions over the transmission and distribution system—represents a step forward for the industry.[155] The follow-up Climate Change Resilience Plan is due from Con Edison in December 2020.

Q. Based on the material you have reviewed, have you identified best practices for climate resilience?

A. Yes, with one caveat. First and foremost, climate-related risk management in electric utility distribution investments to date has focused exclusively on climate-related physical risks, without integrating financial, economic, regulatory, or reputational risks into risk assessment. Among the many co-benefits that enabling renewable distributed energy resources provides, for example, is a hedge to a given firm's regulatory and reputational risk.

Based on our review of emerging climate resilience plans, climate resilience plans proceed through two steps:

- **Forward-looking, high-quality vulnerability assessment.** The U.S. Department of Energy's North American Energy Resilience Model

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[154] ConEdison, (2019, December). Climate Change Vulnerability Study. Retrieved at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.

[155] M.J. Bradley & Associates, (2019, December). Key Considerations for Electric Sector Climate Resilience Policy and Investments. Retrieved at https://www.mjbradley.com/sites/default/files/MJB%26A_KeyConsiderationsforClimateResiliencePolicyandInvestment.pdf.

urges utilities to "transition from the current reactive state-of-practice to a new energy planning and operations paradigm in which we proactively anticipate [damage], predict associated outages, and recommend optimal mitigation strategies."[156] Utilities need to understand their exposure and vulnerability to climate-related risks before they can cost-effectively address them. Climate resilience plans undergo vulnerability studies that look at a wide variety of risks, integrate the most up-to-date scientific work on the matter, and project impacts that these impacts might into specific assets in the future. High-quality vulnerability assessments both identify where largest need for intervention and provide a value 'cost' input into the screen for solutions.

- **Informed, inclusive, and fair solution selection.** The process for identifying and selecting solutions should be robust, to ensure a true 'no-regrets' approach. Solutions screens should be informed by the utility's vulnerability assessment, and they should include a stakeholder-informed wide range of traditional and non-traditional solutions. Finally, utilities and stakeholders should work together and agree on a cost-benefit methodology before considering any single intervention.

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[156] ConEdison (2019, December). Climate Change Vulnerability Study. P. 63.

These steps are supported, in an optimal scenario, by collaboration with stakeholders throughout the process, including while setting a scope and goals for the climate resilience plan. Climate resilience plans are also iterative; as technology develops and vulnerabilities change, resilience plans must be updated.

4. DEVELOPMENTS IN NORTH CAROLINA'S BUSINESS AND POLICY ENVIRONMENT SINCE THE COMPANY'S MOST RECENT RATE CASE

Q. What policy developments, within North Carolina or with Duke Energy Corporation, have occurred since the Company filed its last rate case?

A. Three trends since 2017 are relevant to the Company's climate-related risks. First, state executive and regulatory agencies have announced or began new programs with implications for the state's electric utility industry. Second, Duke Energy Corporation made its non-binding carbon reduction goal announcement in September 2019. Third, ongoing, collaborative processes in North Carolina are creating state-of-the-art climate vulnerability data with implications for designing a more resilient electric grid for North Carolina.

Q. Please describe Executive Order 80 ("EO 80").

A. In order to "build resilient communities and develop strategies to mitigate and prepare for climate-related impacts in North Carolina," Governor Cooper's Executive Order 80 pledges the state to, among other things, reduce statewide emissions by 40% by 2025.[157] Importantly, the Executive Order directs several executive agencies to develop plans for reducing emissions from the energy and transportation sectors. An Interagency Council convened by the Executive Order may also recommend new and updated goals and actions to meaningfully address climate change. Executive Order 80 is provided as Exhibit JMV-TF-7.

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[157] State of North Carolina Exec. Order No. 80, (2018, October).

Q. Please describe the Clean Energy Plan ("CEP").

A. The Clean Energy Plan is a collaborative, stakeholder-driven plan to "foster and encourage the utilization of clean energy resources," developed by the Department of Environmental Quality as directed by Executive Order 80.[158] After a year of conducting workshops and soliciting input from a diverse range of stakeholders, DEQ published its complete Clean Energy Plan in October 2019. The Clean Energy Plan sets ambitious goals for the energy sector, then presents several pathways to work toward those goals alongside short- and long-term actions over the next five years to move along those pathways. While the CEP itself is a complex document with six strategies and over 35 distinct recommendations, the key features of the Plan are summarized in Table 2.

[158] *Ibid.*

Table 2. Key Features of the Clean Energy Plan[159]

Goals	Key Recommendations	Relevant Stakeholders		
Reduce electric power sector emissions by 70% by 2030 and to net-zero by 2050;	Develop carbon reduction policy designs for retiring uneconomic coal; other market-based clean energy policy options	Legislature	NCUC	Governor's Office
Foster long-term energy affordability and price stability for residents and businesses;	Better align utility incentives with public interest, grid needs, and state policy.	State Agencies	Investor-Owned Utilities	Co-ops / Public Utilities
Accelerate clean energy innovation and deployment to create economic opportunities across the state	Modernize the grid to support clean energy resource adoption, resilience, other public interests.	Local Gvmnts	Academia	Business

Q. What are the implications of Executive Order 80 and the Clean Energy Plan on the Company's climate-related risk?

A. EO 80 and the CEP provide a meaningful signal for North Carolina regulatory agencies. They establish the procurement of clean energy and reduction of statewide emissions as a public policy objective and empower regulatory agencies to act in furtherance of that objective.

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[159] North Carolina Department of Environmental Quality, (2019, October), North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System. Retrieved at: https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

It is important to note that neither EO 80 nor the CEP has binding, legal enforceability for its goals. Nevertheless, the two actions may be seen as a directional signal for the future of climate policy in North Carolina.

The Clean Energy Plan also invites investor-owned utilities to act as partners in implementation. While it may be reasonable to see incipient carbon regulations as a regulatory risk, the Company's participation may represent a regulatory opportunity. Strategies B and C of the Clean Energy Plan seek to align interests between stakeholders on the 21st century utility business model and the future of utility system planning. By collaborating on innovative new regulatory mechanisms with public stakeholders, the Company could actually reduce regulatory lag and risks of other regulatory impacts to business operations.

DEQ's responsibility to develop a climate risk assessment and support communities in developing resilience also has implications to the Company. To the extent that electric system resiliency is a component of community resiliency, the Company will necessarily be a relevant party in communities' adaptation and resiliency plans.

Finally, EO 80 empowers the interagency council to recommend updated goals to meaningfully address climate change as appropriate. Therefore, while currently ongoing agency work in support of Executive Order 80 may already add climate-related regulatory risk and opportunities, there is potential for on-going long-term policy engagement between the Company and North Carolina executive agencies.

Q. Are there any public statements that the Company or its holding corporation has made that might impact the Commission's view of the Company's application?

A. Duke Energy Corporation published its non-binding net-zero carbon announcement on September 17, 2019.[160] In the announcement, the corporation projects it will decrease carbon emissions by 50% by 2030, with a goal of net-zero carbon emissions by 2050.

Q. What are the implications of Duke Energy Corporation's carbon announcement on the Company's climate-related risk?

A. While the Company is not explicitly required to meet Duke Energy Corporation's goals, the goal's ambitious timeline all but requires that the Company follow a similar emissions pathway if Duke Energy Corporation is to achieve its goals. As briefly discussed above, the carbon announcement shifts the Company's risk profile. While the urgency and regulatory burden of a regulatory or legislative mandate may be decreased by Duke Energy Corporation's commitment, Duke is also liable to sustain reputational damage and potential regulatory blowback if it is perceived to be missing its goals.

Q. Are there ongoing processes to understand climate vulnerability and resiliency to infrastructure in North Carolina?

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[160] "Duke Energy aims to achieve net-zero carbon emissions by 2050." (2019, September), *Duke Energy News Center.* Retrieved at https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050.

A. Yes. Work is ongoing within two projects related to both infrastructure and climate change currently underway in North Carolina, the results of which will be relevant for the Company's business operations. First, as directed by Executive Order 80, the North Carolina Department of Environmental Quality is currently developing a North Carolina Risk Assessment and Resiliency Plan that will specifically address built infrastructure. As a part of the Risk Assessment and Resiliency Plan, the North Carolina Institute for Climate Research is developing a high-quality climate science report that describes the physical impacts of climate change on North Carolina.[161]

Second, in part thanks to a grant from the US Department of Energy, the North Carolina Clean Energy Technology Center, NC Department of Environmental Quality, and UNC Charlotte's Energy Production Infrastructure Center are participating in a two-year joint research project called "Planning an Affordable, Resilient, and Sustainable Grid in North Carolina."[162] Among other things, the project will take stakeholder input, assess new metrics for evaluating grid resiliency, and "enable a more decentralized, resilient grid." Both of these processes represent opportunities for the Company to meaningfully engage with stakeholders who are generating meaningful, relevant information for a resilient, 21st century grid in North Carolina.

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[161] Kunkel, K., & Easterling, D.
[162] N.C. Clean Energy Technology Center (2020, January). Planning an Affordable, Resilient, and Sustainable Grid in North Carolina. Retrieved at: https://nccleantech.ncsu.edu/2020/01/29/planning-an-affordable-resilient-and-sustainable-grid-in-north-carolina-2/.

5. REVIEW OF THE GRID IMPROVEMENT PLAN IN LIGHT OF THESE RISKS

Q. What portions of the Company's application in this case are you addressing in your testimony?

A. As noted earlier, our review of the Company's application focuses on the Company's proposed Grid Improvement Plan ("GIP"). We review the Plan in light of grid modernization best practices, Vote Solar's participation in the stakeholder process, the emergence of climate-related risks, and recent policy development in North Carolina since the Company's last rate case.

Q. Do you present a program-by-program review of the GIP here?

A. No. We look to North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, North Carolina Sustainable Energy Association, and Southern Alliance for Clean Energy Witnesses Alvarez and Stephens for a granular review of the individual programs that form the Grid Improvement Plan. The review in this testimony will focus more on the process by which the Company selected and scoped these programs and the broader implications for the development of the grid, rather than the technical details of each given program.

Q. What are the criteria that you would apply to a well-designed grid modernization plan in the context of this rate case?

A. While they represent an incomplete justification for any grid investment program, the "Megatrends" described in Witness Oliver's testimony succinctly describe the shifting dynamics of the electric grid. In our view, the Megatrends viewed together do not provide justification for a slate of distribution projects; rather, they underscore the importance of getting our investments in the grid right. The 21st century grid should be resilient to climate-related physical risks, but at the same time it must enable a more dynamic, communicative, and distributed energy system. And, being critical infrastructure for North Carolina, it must be reactive to ongoing physical, regulatory, and technical developments in the state. It's for this reason that the Department of Environmental Quality combines "grid modernization" and "grid resilience and flexibility" together in its Clean Energy Plan.[163]

The Grid Improvement Plan, then, must play multiple roles for the North Carolina electric system. In the previous sections of this testimony, we have explored best practices for grid modernization and climate resilience. We re-produce those best practices, in no specific order, in Table 3 below:

Table 3: Best Practices for Climate Resilience and Grid Modernization

Climate Resilience	Grid Modernization
Forward-looking, high quality vulnerability assessment	Clear, Measurable Goals
	Integrated Distribution Planning
Informed, inclusive, and fair solutions selection	Stakeholder Engagement
	Cost/benefit analysis

[163] North Carolina Department of Environmental Quality (2019, October). North Carolina Clean Energy Plan. P. 82. Retrieved at https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

A. Grid Modernization

Q. Please review the Grid Improvement Plan against grid modernization best practices.

A. Our review of the Grid Improvement Plan against grid modernization best practices is summarized in Table 4, below:

Table 4. Grid Improvement Plan's performance versus Grid Modernization Best Practices

Best Practice	Grid Improvement Plan performance	Implications
Clear, measurable goals	Plan presents "Megatrends" but no measurable goals.	Unclear what 'success' looks like; no way to hold Company accountable; unclear benefits for ratepayers.
Integrated Distribution Planning	Plan will develop capability, but Phase I will not use it.	Plan does not adequately assess potential of NWAs; potential for sub-optimal investment.
Stakeholder Engagement	Company conducted several workshops; use of stakeholder input is not evident from application or stakeholder process.	Plan is less likely to incorporate a wide range of perspectives and value propositions
Cost-benefit analysis	Company does use cost-benefit analysis; no judgment of cost-benefit analysis in this testimony	No implications evaluated in this testimony

Q. Please explain the assessment of the Grid Improvement Plan and its implications in Table 4.

A. **Clear, Measurable Goals:** As a $1.3 billion incremental investment in the grid with inevitable ratepayer cost implications, the Grid Improvement Plan must demonstrate that the benefit provided to customers is worth the cost. The best way to do that is through clear, measurable goals and commitment to outcomes that benefit all stakeholders. These keep expectations for all parties aligned, and quantified goals allow stakeholders and regulators to track the Company's progress throughout the plan.

In lieu of stated goals, the Company offers its Megatrends[164] and Implications.[165] The Megatrends represent actual trends that are playing out on the grid, but we find their use alongside the Implications in this case to justify the Grid Improvement Plan to be inappropriate. The Company's analysis of the Megatrends provides no systematic, quantitative understanding of their impacts on the grid—thereby making effective 'baselining' impossible. Notwithstanding the lack of an appropriate baseline, the Company does not set any goals for the Plan or metrics by which the Company, regulators, stakeholders, or ratepayers could assess the progress of the Plan or hold the Company accountable. The Company declines to demonstrate how any given project within the Plan relates to the Megatrends.[166] In light of the Plan's similarity to Power/Forward, it is difficult to ascertain how the development of the Plan was affected in any way by the Megatrends concept. In

[164] Oliver, Ex. 2.
[165] Oliver, Ex. 3.
[166] Company Response to CBD & AV Data Request 2-44.

this way, the Megatrends may act as a way to provide license to pursue Power/Forward projects, rather than a representation of discrete problems that must be addressed with targeted solutions.

Integrated Distribution Planning ("IDP"): Simply put, integrated distribution planning is the element that enables utilities to "modernize" their grid. The analytical capability that is a hallmark of IDP processes allows electric utilities to understand grid operations at a more granular level, work with the distribution gird as an integrated system, and as a result precisely take advantage of distributed resources and place grid modernization solutions. The Company has proposed IDP components as a part of the Grid Improvement Plan, but these components will be pursued alongside, rather than in advance of, massive capital investment in the grid. Pursuing $1.3B in distribution-level investments[167] (just before these capabilities are online) risks premature deployment of these assets and therefore a sub-optimal cost-benefit for all stakeholders, including the Company.

Stakeholder engagement: Stakeholder engagement for the Grid Improvement Plan has been reviewed above. The process executed by the Company did not adhere to best practices for an effective process and appears to have minimally incorporated stakeholder input.

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[167] Oliver Direct, Ex. 10, p. 3.

Cost-benefit analysis: This review will not cover cost-benefit analysis in depth. Similarly, cost-benefit analysis has not been the focus of this testimony and will not be reviewed.

Q. The Company claims that the projects included as part of the Grid Improvement Plan are "no-regrets," "foundational" projects. Do you agree with that characterization?

A. No. First, the "modernize" projects that Witness Oliver describes as "foundational"[168] form just over a quarter of the total budget of the Plan.[169] Even describing the Plan in the Company's terms, it would be inappropriate to describe the entire plan as "foundational."

Second, many of the projects proposed under the Grid Improvement Plan fall into what GridLab calls "geographical" projects—physical infrastructure installed in specific geographical areas to extend some grid capability.[170] GridLab's report points out that the "need" to extend new capabilities to these areas should emerge from a high-quality, risk-based assessment of vulnerability of current operations. "Foundational" investments are those that make such a need assessment possible, or enable the 'capability' that is being extended through geographical investment. ISOP is the paramount example of a "foundational" investment. The Company's proposed Self-Optimizing Grid, for example, would not qualify as

[168] Oliver Direct, p. 33, l. 9.
[169] Oliver Direct Ex. 12, p. 97.
[170] Alvarez, P., & Stephens, D., p. 16.

"foundational." Some of the projects categorized as "modernize" by the Company, such as distribution system and transmission system automation, would also fall into the "geographical" category.

Q. Does the Company acknowledge that making investments without all necessary information could lead to sub-optimal or imprudent investment?

A. Yes. In a response to a stakeholder question, the Company responded that it was confident "with 85% certainty" that ISOP would not render Grid Improvement Plan investments obsolete.[171] This figure was clearly not intended as a precise estimate, but it provides a ballpark figure for potential losses. To put this number into context, if 15 percent of GIP investment were rendered obsolete by ISOP capabilities, the Grid Improvement Plan as proposed would immediately result in stranded distribution assets worth just under $200 million.[172] The Company must take this risk seriously, and its failure to do so in this proposal represents a major oversight.

Q. Does the Grid Improvement Plan's use of Megatrends and implications represent a prudent management of climate-related risks?

A. In short, no. The Company has failed to demonstrate how any specific projects addresses climate-related impacts,[173] has shown that its interventions do not consider the increasing impacts of climate change,[174] and its approach does not acknowledge the interconnectedness of climate-related risks across generation,

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[171] Oliver Direct Ex. 13, p. 43.
[172] Oliver Direct, Ex. 10, p. 3.
[173] Company Response to Vote Solar DR 3-4 and 3-5.
[174] Company Response to Vote Solar DR 3-16.

transmission, and distribution functions. Making new investments in distribution infrastructure without a systematic assessment or climate-specific data gathering is an insufficient response to climate-related risks. The Company's current approach of willful avoidance of climate analysis is inadequate, if not imprudent, and exposes the currently proposed grid investments to unnecessary and manageable risks.

B. Climate Resilience

Q. Please review the Grid Improvement Plan against grid modernization best practices.

A. Our review of the Grid Improvement Plan against climate resilience plan best practices is summarized in Table 5, below.

Table 5. Grid Improvement Plan's performance versus Climate Resilience Best Practices

Best Practice	Grid Improvement Plan performance	Implications
Forward-looking, high-quality vulnerability assessment	Plan did not utilize any meaningful climate risk assessment.	Ongoing physical risks to grid assets and reliability; less cost-effective projects.
Informed, Inclusive, and Fair Solutions Selection	Plan uses a solutions-first approach and cost-benefit analysis developed after the fact.	Non-'traditional' alternatives likely excluded from Plan; missing potential co-benefits.

Q. Does the Company explicitly acknowledge the presence of climate-related risks or make any attempt to systematically manage them in its application or in discovery?

A. No. As noted above, the Company has represented that it has incorporated climate-related risk only to the extent that it is included as part of the "Megatrends" identified by the Company,[175] although it also stated that it is "without knowledge" as to the role of climate change in weather events.[176]

Q. Please explain your assessment of the Grid Improvement Plan and the implications of the Plan in Table 5.

A. **High-quality Risk Assessment:** We conducted an in-depth comparison of risk assessment and solution selection between the Grid Improvement Plan and Con Edison's Climate Change Vulnerability Study. The results of that comparison are presented in Appendix JVN-TF-6. Con Edison's climate vulnerability study estimated that climate risks would cost the utility between $1.3 and $4.6 billion by 2050,[177] while the Company, for its part, has presented no quantitative risks of climate-related risks. As an example of a potential risk identified by Con Edison but ignored by the Company, Con Edison estimates that flood risks may exceed design specifications by as early as 2030.[178] Duke Energy Carolinas' flood risk design specifications are roughly equivalent to Con Edison's, [179] but it did not

[175] Company Response to Vote Solar Data Request 1-3, *via* Company Response to Vote Solar Data Request 1-2 Supplemental.
[176] Company Response to Vote Solar Data Request 1 – 3 Supplemental.
[177] Consolidated Edison Company of New York Inc. ("ConEd"), (2019, December). Climate Change Vulnerability Study ("ConEd Climate Study"). P. 4. Retrieved at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.
[178] ConEd Climate Study, p.5.
[179] Company Response to Vote Solar Data Request 3-16.

assess the potential that those specifications would become outdated or the material risks to assets that would occur as a result.

The comparison shows that, compared to the industry standard and even a reasonable understanding of climate-related risks, the Company did not complete any systematic climate risk assessment to its assets or operations. There may be individual examinations of factors that may be impacted by climate change, such as flood risk, but those analyses are backward-looking and do not incorporate likely future climate impacts.[180] The Company's risk assessment is mostly represented by the "Implications" of its Megatrends, which remain are simply too high-level and qualitative to precisely design a programmatic intervention. In comparison, the Con Edison Vulnerability Study pursued an asset-level risk screen, mirroring the granularity of studies conducted by financial institutions and discussed earlier in this testimony.[181]

Like any other business risk, when climate-related risks are not managed, the Company (and therefore its customers) are more exposed to negative outcomes. And, as we have discussed above, physical risks may spill over into insurance, financial, reputational, or regulatory risks.

Informed, Inclusive, and Fair Solutions Selection: Witness Oliver summarizes the process by which the Grid Improvement Plan was developed in his

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[180] Company Response to Vote Solar Data Request 3-24.
[181] Bertolotti et al.

testimony.[182] The process was not conducted in collaboration with stakeholders; beyond identifying the existence of the Megatrends, there are no stated goals; solutions are not informed by high quality vulnerability assessment; selection criteria are not defined, beyond vague programmatic terminology;[183] there is no indication for how the geography or scale of any given intervention was decided; 'tools' are a narrow range of traditional solutions; and cost-benefit was performed after the fact, rather than designed in advance of the consideration of any particular project and used as a screening tool.

This approach constrains what is possible under the Grid Improvement Plan. It leaves very little room for assessment of co-benefits, pre-determines a narrow set of potential solutions, and ignores non-wires or non-standard alternatives.

C. NC Context

Q. Does this process acknowledge the other, ongoing processes to quantify grid vulnerability, modernize the electric system, or increase resilience in North Carolina?

A. No. Witness Oliver's testimony does not mention "Clean Energy Plan" or "Executive 80," nor does it refer to either ongoing research project we discuss above.[184] Although one of the identified Megatrends is "Environmental Trends" or

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[182] Oliver Direct, p. 32, l.19 – p. 33, l. 20.
[183] Oliver Direct, Ex. 5.
[184] Oliver Direct.

"Environmental Commitments," its description of these environmental commitments is exclusively backward-looking.[185] Discussion of environmental commitments in Oliver Exhibit 4 do not mention the Clean Energy Plan or Executive Order 80.

Q. What are the implications of this omission?

A. It's an unfortunate disconnect between a potentially large investment of assets on the grid through the Grid Improvement Plan, unfolding at the same time as many simultaneous conversations are developing in the North Carolina policy community. For the Company, not engaging with these processes misses an opportunity to gain working knowledge that could inform the details of the Plan, and increases the potential for obsolescence, stranded assets, or increased costs because of an operations and communication disconnect between Company practice and regulatory policy.

D. Review Overall

Q. Do you see an opportunity for an effective grid modernization and climate resiliency proposal at this time in North Carolina?

A. Yes. We agree that recent trends are changing the way customers use the grid and, as we demonstrate above, climate-related risks and opportunities will shape the electric utility business moving into the future. At the same time, a natural synergy exists between the Company's engagement in integrated planning and circuit-level

[185] Oliver Direct, Exhibit 4.

analysis through ISOP and Advanced Distribution Planning and the vibrant policy conversation in North Carolina discussing the very nature of the grid in the 21st century. And, as we document in Section 2, best practices from other states and proceedings are emerging to light the way toward a clear grid modernization and climate resiliency plan that has benefits for all stakeholders. A truly collaborative grid modernization process that creates goals and accountability in partnership with stakeholders, gathers all of critical information (including climate-risk-related and distribution operations information) needed for grid planning first, then selects projects through an open and transparent process second could deliver substantial, lasting benefits for all stakeholders.

Q. Does the Grid Improvement Plan deliver on the potential for a well-designed grid modernization or climate resilience plan?

A. No. As we discussed above, the Company does not have the input from stakeholders (including state executive agencies), climate-related factors, or distribution-level analysis it needs to design a true no-regrets Plan. Partly as a result, the Plan does not contain overall goals or tracking metrics that would allow stakeholders and regulators to maintain reliability. Finally, instead of engaging in an open, transparent assessment of solutions and investments (including non-wires alternatives and distributed energy resources), the majority of the Plan consists of solutions that were proposed under Power/Forward.[186]

[186] Company Response to NCSEA Data Request 3-7.

As a result, there is a massive potential opportunity cost for proceeding with this plan. At a time when best practices are emerging from a changing national landscape, the Company's own sophisticated distribution planning capabilities are coming online, and stakeholders are proactively pursuing deep, informed engagement, the Company's proposal does not take advantage of those developments. The Company's informal assessment of opportunity costs from declining to inform their Plan with advanced distribution planning could be around $200 million, as described above.[187] Because the Company has not undertaken an assessment of its climate risks, that opportunity cost remains unquantified.

Q. Do you believe that a positive benefit-cost ratio is sufficient justification for moving forward with any given project?

A. No. Cost-benefit analyses answer the question, "How does this investment compare to business-as-usual, or no intervention at all?" As stakeholders in the modernization of the grid, the answer we should be more concerned with is "how does this investment compare to a well-executed grid modernization and climate resilience plan in the public interest?" Against this counterfactual, a project with a positive benefit-to-cost ratio might still represent a missed opportunity. Because the Company did not effectively pursue a climate vulnerability study, stakeholder input, or integrated distribution planning, it lacks the information needed to conduct such a comparison.

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[187] Oliver Direct, Ex. 13, p. 43.

Q. What role could distributed energy resources (DERs) play in grid modernization and climate resilience?

A. Distributed Energy Resources bring unique benefits to both grid modernization and climate resilience program goals. A comprehensive grid modernization or climate resilience plan should ensure that DERs are fully valued versus traditional solutions.

In a climate resiliency context, DERs provide the critical service of generating energy close to load. In cases such as extreme weather events when distribution or transmission systems are not working at full capacity, "islandable" DERs can continue to provide power to ratepayers.[188]

In a grid modernization context, DERs may be able to fulfill distribution system operational needs more cost effectively than traditional investments, or defer the need for incremental investments in distribution assets. In this context, DERs are often referred to as non-wires alternatives (NWAs) or non-traditional solutions (NTS). A recent Duke Energy webinar demonstrating the anticipated functionality of ISOP explained that ISOP analytical capability would be able to weigh benefits of DERs versus traditional solutions and identify where NWAs might be more cost-effective.[189] A typical deferred investment by NWAs is

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[188] ConEd Climate Study, p. 49
[189] Duke Energy (2020, January). ISOP Stakeholder Webinar. Retrieved at: https://www.duke-energy.com/_/media/pdfs/our-company/200062/isop-webinar-1-presentation.pdf?la=en.

increased line capacity, which is a major component of the Self-Optimizing Grid GIP project.[190]

Q. Do you believe the Grid Improvement Plan appropriately considered DERs and NWAs in the development of potential solutions?

A. No. DERs and NWAs are disruptive solutions, and they require proactive analysis and planning to be fully valued in utility planning. First, the utility needs the data to understand DER benefits. That includes both climate vulnerability, ascertained through a vulnerability study as demonstrated above, and detailed distribution operations data created through an integrated distribution planning process. Then, the utility should use a systematic solutions selection process that incorporates climate and distribution data, values co-benefits, and fairly values DERs against traditional solutions.

The Company did not pursue these steps before developing the Grid Improvement Plan. By pursuing its grid modernization planning in this manner, the Company constrained the role of DERs in its Plan and likely lost potential cost-effectiveness benefits for both the Company and its customers.

Q. Are there any programs proposed in the Grid Improvement Plan that you approve?

A. Yes. The Integrated Systems & Operations Planning program is a truly innovative program that could enable a more dynamic grid, and its Advanced Distribution

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[190] Oliver, Ex. 10.

Planning and Morecast components both represent major steps forward in analytical capacities for distribution planning. We support this program.

Similarly, IVVC is a program with a high benefit-to-cost ratio and many clear benefits. We support the Company's investment in this program.

6. DISCUSSION OF THE COMPANY'S GRID IMPROVEMENT PLAN AND THE BURDEN OF PROOF

A. Deferral Accounting Request

Q. Describe the Company's request for approval of deferral accounting.

A. The Company is requesting to defer costs related to the Grid Improvement Plan into a regulatory asset for recovery in future rate cases.[191] More specifically, the Company is requesting deferral of the North Carolina retail share of the following types of costs for its Grid Improvement Plan: depreciation of capital investments, return on capital investments (net of accumulated depreciation) at the Company's weighted average cost of capital, O&M expense related to the installation of equipment, property tax related to the capital investments, and a return of the balance of costs deferred at the Company's weighted average cost of capital.[192]

Q. Is use of deferral accounting for the types of investments in the GIP in years 2020 through 2022 typical in the utility industry?

A. No. Deferred accounting by its very nature is an extraordinary ratemaking tool, and it would be a departure from customary ratemaking practices to use deferred accounting in these particular circumstances.

Q. Why is deferral accounting considered extraordinary relief in regulatory practice?

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[191] Direct Testimony of Company Witness Jane L. McManeus ("McManeus Direct"), p. 37-38.
[192] McManeus Direct, p. 38, l. 6-12.

A. The strong presumption is that general rate proceedings are the primary forum for evaluating the prudence of utility investments, updating the utility rate base to reflect the addition of such investments, and capturing in rates the impact on operating expenses, deprecation and return associated with such investments. In the case of large capital investments, the use of an allowance for funds used during construction (AFUDC) typically provides adequate compensation for a utility's undertaking of significant multi-year investments. Through AFUDC, the utility is allowed to capitalize the financing costs of such investments prior to their completion and inclusion in rate base, with such capitalized costs being added to the original investment upon which the utility is allowed to earn a return and which is amortized over time through depreciation. This is the ordinary and routine ratemaking process for large capital investments.

Q. Why is the Company seeking extraordinary treatment for the GIP investments made in years 2020 through 2022 in this case?

A. The Company contends that costs related to the Grid Improvement Plan are "major, non-routine investments, that produce substantial customer benefit," and that this description "meets the Commission's traditional test for deferral." Company Witness McManeus also notes that absent deferral the Company will "experience a significant adverse earnings impact."[193] According to the Company's testimony, in the absence of the requested deferred accounting treatment, the "earnings

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[193] McManeus Direct, p. 39, ll. 7-18.

degradation is expected to grow to over 100 basis points by 2022, the third year of the plan."[194]

Q. Is the relief sought in this case similar to the relief sought in the last case with the Power/Forward grid investment and modernization initiative?

A. Yes. As discussed above, in its previous rate case, the Company sought permission to recover Power/Forward costs through either a bill rider or deferral into a regulatory asset for similar cited reasons.[195]

Q. Why did the Commission deny extraordinary treatment of expenses incurred outside of the test year in the previous rate case?

A. As cited above, the Commission found that "the reasons DEC says underlie the need to Power Forward are not unique or extraordinary… [they] are all issues the Company [has] to confront in the normal course of providing electric service… A number of the Power Forward programs …are the kinds of activities in which the Company engages or should engage on a routine and continuous basis."[196]

Q. Are you aware of Senate Bill 559, which was passed by the North Carolina General Assembly in 2019?

A. Yes. My understanding of Senate Bill 559 is that a major feature cut from the bill before it passed would have authorized utilities to request, and the Commission to grant, multi-year rate plans.

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[194] McManeus Direct, p. 39, ll. 12-14.
[195] Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146 et al. p. 142-145. Retrieved at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.
[196] *Ibid,.* p. 146.

Q. Would a multi-year rate plan provide a means for addressing situation for which the Company is seeking extraordinary relief for these GIP expenses incurred outside of the test year?

A. Yes. While the elements of a multi-year rate plan would typically be established through the ratemaking process, a likely element would be the periodic updating of the utility's rate base to reflect anticipated major capital investments, such as the Grid Improvement Program. Allowing the utility to update its rate base to include such investments (and the associated expenses) would go a long way towards eliminating the impact of regulatory lag, which seems to be the primary motivation in the Company's request for deferred accounting in this case. According to the Company, in the absence of deferred accounting, its earned return on equity would erode by 100 basis points by the end of the third year of the Grid Improvement Plan. (Of course, that assumes the Company would not file more frequent rate cases as a means of updating its rate base, which is another tool available to a utility to minimize the impact of regulatory lag.)

Q. Based on your knowledge of other states, do multi-year rate plans provide a more appropriate basis for regulatory consideration of forward year investments, such as those sought here?

A. Multi-year rate plans are certainly one means of addressing the issue, assuming there is the statutory authority for entering into such plans. (Even in the absence of express statutory authority, it is sometimes possible for multi-year rate plans to be implemented through agreement by all parties in a proceeding, as is commonly done through settlements in rate cases involving the New York electric utilities.) As part of a multi-year rate plan, I would expect to see a mechanism established that would provide the same level of scrutiny for evaluating the prudence of forward year investments. In other words, the traditional general rate case process provides a good forum for closely scrutinizing the reasonableness of the expenditures and whether the utility has borne its burden of proof in showing that it is undertaking such investments in a manner that minimizes the long-term costs for its customers. Any multi-year rate plan would need to include a process that includes these essential protections for customers. We discuss this in the following section.

Q. Why would a major, comprehensive grid investment scheme like GIP not fit within a utility's ordinary course of seeking cost recovery through rate cases?

A. It typically would, for the reasons stated above, and the Company has the burden to show why the extraordinary remedy of deferred accounting is necessary. As noted above, the Company's position is that the Grid Improvement Plan comprises "major, non-routine investments, that produce substantial customer benefit," and that its request "meets the Commission's traditional test for deferral." Whether or not the Company's proposal is acceptable to the Commission, of course, is entirely up to the Commission; as discussed below, the Commission has substantial discretion in deciding whether or not to allow deferred accounting, and to define the terms under which deferred accounting will be allowed.

Q. When generation and transmission projects are proposed, which are often multiple-year construction projects with long lead times, does the Commission have a process for determining whether the project is necessary?

A. Yes. It is fairly common for utilities to be required to secure a Certificate of Public Convenience and Necessity ("CPCN"), which requires the utility to demonstrate that the generating or transmission project is necessary and that the costs are reasonable. North Carolina has a similar requirement in the case of generating plants (NC GS 110.1) and transmission lines (NC GS 62-105a).

Q. Do major, comprehensive grid investment schemes like the GIP fall within a regulatory gap?

A. I think the Company has made a decent case that the current ratemaking mechanisms available to it do not fit well with the type of projects comprising the Grid Improvement Plan. As described in the Company's testimony, most of the projects included within the Grid Improvement do not, because of their magnitude and duration, qualify for the AFUDC treatment that was mentioned earlier. There will be some earnings erosion associated with implementing the Grid Improvement Plan in the absence of deferred accounting or a multi-year rate plan that includes periodic updating of the Company's rate base. In addition to the earnings impacts, there is probably a strong basis for providing a regulatory forum for evaluating and approving a comprehensive multi-year program that does not fit neatly within the standard general rate case.

Q. Are major, comprehensive grid investment schemes like the GIP more prevalent around the country in the last decade?

A. Yes, there are several states that are moving towards a more comprehensive grid planning process, given the fundamental changes that are underway in the electric utility industry. For the most part, this process is necessary to accommodate the expanded use of DERs given the failure of traditional planning processes to integrate DERs into long-term planning (historically was based on one-way power flows from the utility's large, centralized generating stations to end use customers). Both California and New York are well down the path of requiring utilities to engage with stakeholders in distribution system planning which, among other things, identifies the opportunities for strategic deployment of DERs by third parties that can result in lower costs to ratepayers over time. Another driver for comprehensive grid planning is addressing the impacts of climate change, which similarly requires a departure from the traditional planning model that was based largely on historical trends in customer and load growth rather than considering the impact of rising temperatures and sea level, and the increasing frequency of extreme weather evens.

Q. Does a deferral accounting request, such as the Company has proposed here for the GIP expenses incurred in the years 2020 through 2022, provide the Commission the same opportunity to evaluate the reasonableness of the proposed investments before they are built as a CPCN process?

A. No. Deferred accounting, almost by its very nature, does not produce the same level of regulatory scrutiny as is afforded by the traditional ratemaking processes of general rate cases and the CPCN process.

Q. Does the practice of using the extraordinary relief of deferral accounting for the GIP shift risks to ratepayers?

A. Yes. In general, ratepayers' interests are well-served by the reliance on traditional general rate cases for setting rates, and the associated regulatory lag that produces a strong incentive for a utility to hold down costs. Streamlining that process through the use of deferred accounting reduces the regulatory oversight that results from the general rate case process, and largely eliminates the economic incentive from regulatory lag to hold down costs.

Q. Going forward, do you have any recommendations for addressing this current regulatory gap to provide better oversight of forward year investment schemes for the Commission and steady revenue recovery for the Company?

A. Yes. As discussed in the next section, we recommend a regulatory scheme that involves (1) a rigorous planning process that, among other things, properly integrates the impacts of climate change, and (2) addresses the Company's legitimate concerns about rate recovery while providing strong incentives for the Company to engage in a planning process that is geared toward minimizing the costs borne by its customers over time (which necessarily requires the integration of climate change impacts).

B. Need for an Integrated System Planning Process

Q. You recommend a new, integrated system planning process to address the regulatory gap that the Company is temporarily trying to fill with its extraordinary deferral accounting request. Please describe that recommendation.

A. Future investments in the Company's grid must be subject to a process that thoroughly considers the impacts of such investments in addressing, and minimizing, climate change-related impacts. Given what we know about the impact of past extreme weather events on the Company's system, it is imperative that any future grid investment be evaluated in light of the Company's vulnerability to climate-driven risks, and how such investments address those risks. Such an analysis is essential if the Commission is to fulfill its obligation to minimize the long-term rate impacts to the Company's customers, and to maximize the reliability (at reasonable costs) of the electric service provided to the Company's customers.

Q. Is there any precedent of a utility commission initiating such a process out of a general rate case proceeding?

A. Yes. The process with which we are most familiar is the Con Edison rate proceeding in New York following Superstorm Sandy, which occurred in October 2012.

Q. How is the Con Edison rate case example similar to the current case?

A. Following Superstorm Sandy in October 2012, Con Edison in January 2013 filed a massive general rate request proposing to "harden the utility's system" in response to Con Edison's experience in coping with Superstorm Sandy. Among other things, Con Edison promised to spend $1 billion over the next four years to harden its system in response to what it learned during Superstorm Sandy. In response, several environmental organizations filed testimony as the "Clean Energy Parties" to propose a different strategy, based on lessons learned in terms of "where the lights stayed on" during Superstorm Sandy (i.e., areas served by microgrids and DERs). Among other things, the Clean Energy Parties proposed that Con Edison's proposed grid expenditures be subjected to a rigorous examination of their resilience benefits, by subjecting the expenditures to examination by a Storm Hardening and Resiliency Collaborative. In other words, rather than following a "business as usual" approach of spending money to harden the system in light of the most recent extreme weather event, the utility was expected to evaluate its T&D expenditures in a manner that would improve its grid resilience in light of climate change and the increasing frequency of extreme weather events. That process ultimately led to the development of the Climate Change Vulnerability Study, which was released by Con Edison in December 2019, attached as Exhibit JMV-TF-4.

Q. In what ways does the climate resilience grid investment strategy outlined in the Con Edison Climate Change Vulnerability Study similar to the GIP?

A. There is very little similarity to the rigorous process followed by Con Edison in its Climate Change Vulnerability Study to the process followed by the Company in developing its Grid Improvement Plan. In contrast to the Company's failure to consider the impact of likely trends with respect to temperature, sea level rise or the frequency of extreme weather events, the Climate Change Vulnerability Study performed by Con Edison considered the range of scenarios involving, among other things, anticipated temperature, humidity and sea level increases, as well as the frequency of extreme weather events, and evaluated the value of its grid investments according to the resilience benefits that such investments would provide to the grid.

Q. Compared to the recommended grid investment strategy outlined in the Con Edison report, does the GIP present a comprehensive strategy to approach resiliency on a system-wide basis?

A. No, the Company's Grid Improvement Plan is woefully deficient with respect to the integration of climate change impacts in its long-term planning, for the reasons discussed in the preceding section.

Q. Based on your experience, what process provides the best means to match the state policy goals with the Company's stated investment strategy and objectives?

A. As described in the preceding sections of this testimony, North Carolina has recognized the imminent threat associated with climate change, and has articulated broad policy objectives that are consistent with minimizing that threat—through mitigation measures such as reduction in GHG emissions—as well as the measures necessary to address adaptation to the "new normal" going forward. The Company's Grid Improvement Plan neither addresses the mitigation possibilities nor the adaptation measures that are necessary to cope with climate change-related risks through achieving increased resilience in the Company's network.

C. Prudency and Burden of Proof in Light of Climate-Related Risks

Q. What is the utility's obligation to address the risks associated with climate change in its rate filings?

A. Nothing is different about the utility's obligation to demonstrate that its actions—as incorporated in its rate proposals—reflect the investments and expenditures that result in the lowest costs to customers over time. In order to recover their proposed expenditures in rates, utilities generally must demonstrate that they are prudently managing their expenses, and proceeding down a path of making investments and incurring expenditures that result in reasonable rates to customers over time. The risks associated with climate change now need to be part of that ratemaking equation. If utilities fail to take climate change risks into account, and continue to make investments in T&D infrastructure or incur other expenditures that fail to improve the resilience of the utility grid in the face of climate change, they run the risk of having those investments disallowed as imprudent. As a matter of prudent utility practice, utilities have the obligation to demonstrate that they have integrated the risks associated with climate change into their long-term planning for T&D investments, and the associated expenditures.

Q. How does the threat of climate change affect the utility's burden of proof in rate proceedings?

A. If a utility fails to demonstrate that it is proceeding down a path that takes climate change-related risks into account and minimizes the costs to customers after taking those associated climate change-related risks into account, their T&D investments (and associated expenditures) are subject to disallowance. It is the "new normal" with respect to prudent utility practice. It is no longer acceptable to expect to recover in rates the investments that are made, if such investments are not mindful of the impacts of climate change and are not designed to improve grid resilience in light of such climate change.

Q. How would you define adequate consideration of climate vulnerabilities?

A. The Con Edison Climate Change Vulnerability Study probably represents the current state of the art in demonstrating how an electric utility should integrate the likely impacts of climate change in its long-term planning process. The extent to which utilities should be expected to integrate the risks associated with climate change in their long-term planning should depend on the circumstances unique to each utility. In that regard, the Company faces an enhanced obligation to integrate climate change into its long-term planning, given the extent to which the financial community has identified the Company as having some of the greatest exposures to climate change impacts of any electric utility in the country. Thus, the Company's failure to integrate such impacts into its analysis affects not only the level of operating costs it incurs over time, but also the capital costs borne by its customers to the extent that the financial community perceives that the Company is doing a poor job of managing those risks, and accordingly demands a higher cost of capital for the costs of financing the Company's investments.

Q. Are you aware of any processes underway in North Carolina that the Company could utilize existing climate science and climate analytics to inform its decision making?

A. Yes. As noted above, there is a current proceeding at the North Carolina Department of Environmental Quality—Phase 2 of the climate risk and resilience group—that is relevant to the type of analysis that should be required of the Company going forward. NCICS has performed a high-value granular analysis of likely climate conditions in North Carolina through the remainder of the century (publication pending). Through funding from the US Department of Energy, the NC State Clean Energy Technology Center is hosting a collaborative process that is going to look precisely at this issue.

Q. Would it be reasonable for the Company to utilize the data and expertise gathered from these various working groups to inform its own system planning process with the best available climate science and scenario analysis techniques?

A. Yes. In fact, it would be unreasonable, and inconsistent with prudent utility practice, for the Company to fail to incorporate these resources to help prioritize strategies and investments to improve the resilience of the Company's network in the face of increasing risks from climate change.

Q. Did the Company perform any forward-looking analysis of climate-related data to inform its recommended GIP investments?

A. No. As described in the preceding section, the Company failed to take into account what we currently know about possible scenarios regarding temperature, humidity, precipitation, and sea level increases over time. It is irresponsible, and contrary to prudent utility practice, to base long-term planning on historical trends that simply do not reflect the new reality of the impacts of climate change going forward. And the consequence of this failure would be to impose unnecessary costs on the Company's customers, which would be disallowed in the typical ratemaking process. The better outcome than relying on the end-loaded disallowance, of course, is to require the Company to engage in a rigorous planning process that integrates the impact of climate change.

Q. Does this mean the Company's GIP fails to carry the burden of proof at this time?

A. No, there is not enough data available as of yet to determine if the Company made the most prudent prioritization and investments in light of its actual, projected climate risk. However, the failure to even attempt to quantify and identify its climate vulnerabilities, in our view, dramatically increases the risk that these investments could prove more costly to ratepayers over time than investments made under a strategy that diligently considered and mitigates future climate vulnerabilities.

Q. If you are not recommending disallowance now based on the Company's failure to consider climate risk, why should the Commission consider climate risk as a necessary consideration to justify the prudency of these types of climate-vulnerable infrastructure investments going forward?

A. The risks are intensifying and the impacts are growing. The need to mitigate to be cost-effective is growing. The visibility and confidence level of future climate data are growing. Based on the standard of doing what a reasonable manager would do based on what they know or *should know*, willful blindness to the reality of climate change going forward cannot be a defense. The Company simply must do better if it is to fulfill its fundamental obligation to engage in practices that result in the lowest costs to its customers over time.

D. Incentive Mechanisms to Encourage Integration of Climate-Related Risks

Q. How can the Company be encouraged to integrate climate-related risks into its long-term system planning?

A. As noted above, the Commission has considerable discretion in deciding whether or not to authorize deferred accounting treatment for the Company's Grid Improvement Plan. The Commission previously rejected deferred accounting treatment for the Company's proposed Power Forward program, which in many ways is replicated by the Company's proposal in this case with respect to the Grid Improvement Program. Notwithstanding the similarities, the Commission has the authority to address any perceived deficiencies through a properly structured incentive mechanism. We recommend consideration of a performance-based incentive mechanism that would properly penalize or reward the Company for integrating climate change-related risks into its long-term system planning.

Q. What are the elements of this performance-based incentive mechanism?

A. As noted earlier in this testimony, the Company is seeking to defer the investment and costs related to its Grid Improvement Plan, and to earn a return equal to its weighted average cost of capital (WACC) on the unamortized balance. The

Commission has the discretion to determine whether or not to grant the Company's deferral request and, correspondingly, has the authority to impose conditions on granting that request. We recommend that the Company's ability to earn its WACC on the unamortized balance of Grid Improvement Plan investments be subject to a performance-based incentive mechanism. In other words, the extent to which the Company is allowed to earn its WACC should be a function of its success in integrating climate change-related risks into its Grid Improvement Plan. We propose that the portion of the WACC be weighted according to the Company's success in achieving certain prescribed metrics that reflect the integration of climate change-related risks into long-term system planning.

Q. How would such an incentive mechanism operate?

A. If the Company does a good job of meeting such metrics, it would be allowed to earn its WACC on the unamortized balance. If the Company falls short, the return it is allowed to earn on the unamortized balance would be less than its WACC. To make the incentive mechanism symmetrical, the Company should have an opportunity to earn a return greater than its WACC. In other words, the Company should be rewarded to the extent that it does an exemplary job of integrating climate change-related risks, and could earn a return in excess of its WACC upon exceeding the prescribed metrics.

Q. Is there precedent for such a performance-based mechanism?

A. Yes. Under the Future Energy Jobs Act passed by the Illinois legislature in December 2016, electric utilities in that state have the option of capitalizing the investment they make in energy efficiency measures, and to amortize such investment over the measures' useful lives. The return they earn on the unamortized balance of such investments is subject to performance-based metrics that capture the utilities' respective performance in achieving energy efficiency savings. The performance-based incentives under the Future Energy Jobs Act operate to reward utilities for exceeding their energy efficiency savings targets and to impose penalties if they fall short.[197] Another example is the use of earnings adjustment mechanisms by the New York Public Service Commission as part of its Reforming the Energy Vision ("REV") programs. Under the "Track Two" Order in the REV proceeding, a utility can be provided with incentives up to the dollar equivalent of 100 basis points of its return on equity based on their ability to implement various measures that are consistent with REV objectives, such as facilitating interconnection of DERs, increasing electric usage intensity (i.e. reducing peak and improving load factor), encouraging customer engagement, and implementing beneficial electrification programs (e.g., heat pumps) geared toward greenhouse gas reductions.[198]

Q. What sort of metrics could be included in such a mechanism to capture the Company's integration of climate change-related risks?

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[197] The Future Energy Jobs Bill (SB 2814) was enacted into law on December 7, 2016, as Public Act 99-0906, with an effective date of June 1, 2017.
[198] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (May 19, 2016), pp. 53-93.

A. There are several measures that would reflect the improvement in the resilience of the Company's network in the face of climate change risks, such as (1) improvements in reliability-related statistics (e.g., SAIDI, SAIFI, or MAIFI), (2) hosting capacity for DERs (measured in kWs), (3) voltage reductions (measured as average annual voltage by circuit), (4) demand response from time-varying rates (measured in kWs), (5) participation in time-varying rates (as a percentage of customers), or (6) operational savings, measured in dollars or dollars per average bill. These metrics would capture the sort of benefits that one should expect from large investments in the Company's grid. These performance targets should be quantifiable, not subjective; should include achievement dates; and be based on outcomes, not processes.

Q. How would this mechanism and these metrics be established?

A. These issues are beyond the scope of this proceeding, and should be considered in a subsequent proceeding on comprehensive and integrated grid planning. The record in this case would simply not support a thorough evaluation consideration of these issues, which would benefit from a full examination by all the interested stakeholders.

7. CLIMATE RISK AND CUSTOMERS

Q. How do customers figure into the discussion of utilities and climate risk?

A. Customers are directly affected by the impacts of climate-related physical risks, with respect to both the quality/reliability of their service and the costs of that service. Upon the occurrence of an extreme weather event, customers' electric service is subject to interruption for extended periods. Actions by the utility to improve the resilience of the grid thus should reduce the adverse impacts on service arising from extreme weather events. Similarly, integration of climate change-related risks in the utility's long-term system planning should result in lower costs for customers over time, as the utility will avoid or minimize investments in facilities that are vulnerable to extreme weather events, thereby minimizing the storm damage costs that ultimately are recovered in utility rates. The extent to which utilities engage in resilience-related investments to reduce their climate-related risks thus redound to the benefit of customers.

Q. Are there particular groups that are expected to be more vulnerable to the electric service-related impacts of climate change?

A. Climate adaptation and vulnerability studies show that the most socially vulnerable households today often bear the most exposure to climate-related risks.[199,200] These

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[199] Lynn, K., MacKendrick, K., & Donoghue, E., (2011, August). Social Vulnerability and Climate Change: Synthesis of Literature. *US Forest Service.* Retrieved at: https://www.fs.fed.us/pnw/pubs/pnw_gtr838.pdf.

[200] U.S. Global Change Research Program (2016). The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. *Populations of Concern.* Retrieved at: https://health2016.globalchange.gov/populations-concern.

households often lack access to resources necessary to cope with climate-related shocks and stresses. Specifically, low-income households and communities of color[201]—commonly referred to as "environmental justice communities"—and those at home who are medically dependent on electricity[202] are especially likely to be vulnerable to climate-related risks. Thus, the consequences of a utility's failure to integrate climate change-related risks into its long-term system planning will fall disproportionately on segments of the population least capable of coping with the impacts.

Q. Are there potential customer programs that the Company could pursue through ISOP, or otherwise, that could address the needs of their most vulnerable customers and communities?

A. Yes. As discussed above, DERs have unique resilience benefits in that they can generate energy closest to where it is needed. With the right kind of forward-looking planning, DERs could be deployed through ISOP or other resource planning proceedings to equip these communities with the assets and resources to withstand climate-related risks. Some examples of potential programs could be storage "resilience hubs" in vulnerable neighborhoods, or behind-the-meter solar plus storage programs for medically vulnerable ratepayers.

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[201] Coffee, J. (2018, February). Climate Disasters Hurt the Poor the Most. Here's What We Can Do About it. *Governing.* Retrieved at: https://www.governing.com/commentary/col-disasters-disadvantaged-climate-justice.html.

[202] Dominianni, C., Ahmed, M., Johnson, S., Blum, M., Ito, K., Lane, K., (2018, July). Power Outage Preparedness and Concern among Vulnerable New York City Residents. *Journal of Urban Health.* Retrieved at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC6181821/.

Q. What are your recommendations to protect customers, and in particular low-income customers, from the rate impacts associated with climate change-related risk and grid resiliency strategies going forward?

A. Ultimately, prudent management of climate-related risks by the utility should produce the desired effect of minimizing rate impacts of climate-related risks and, to the extent such risks are not managed prudently, regulators have a responsibility to ensure that imprudent costs are not passed on to customers, whether low-income or not. The Commission is uniquely situated to exercise its full range of options to minimize rate impacts through, among other things, the period over which grid resilience investments are amortized or how such costs are allocated to customer classes.

Targeted climate resilience investments could also provide relief for low-income customers. Solar plus storage investments, for example, could decrease bills while ensuring resilience against climate impacts. Equitable access to such measures, of course, is a challenge, and the Commission may wish to focus particular attention to developing programs that facilitate access to such investments by environmental justice communities.

8. CONCLUSIONS AND RECOMMENDATIONS

Q. Based on your review of the Company's filing and emerging electric utility trends, what conclusions do you reach in this testimony?

A. We reach the following conclusions:

- Climate-related risks, emerging in many vectors, have a material and substantial bearing on the Company's operations today and will continue to affect operations in the future. Collaborative processes in North Carolina are at work today to assess these risks and their implications for the electric grid.
- The Company faces demonstrable physical risks from climate change and increasing scrutiny on climate risk management from relevant financial institutions.
- As a potential foundational investment for the 21st century grid, any grid modernization plan should consider best climate resilience practices alongside grid modernization best practices. This includes the fair assessment of distributed energy resources as climate resilience and grid modernization solutions.
- The Grid Transformation Plan, as filed, does not assess or respond to climate-related risks, nor does it adhere to grid modernization best practices. As a result, the Company's proposal does not provide enough information to indicate that the Plan is a prudent investment.

Q. Based on your review of the Company's filing and emerging electric utility trends, what recommendations do you make in this testimony?

A. We respectfully ask that the Commission should:

- Direct the Company to assess and manage climate-related risks across its operations and assets, in accordance with prudent utility practice.
- Make clear that it will apply this standard to Grid Improvement Plan investments by the Company.
- Direct the Company to participate in ongoing Department of Environmental Quality stakeholder processes around grid modernization and integrate data, findings, and recommendations, into its grid modernization investments. The Commission should further require that the Company file a repot by December 31, 2020 identifying any gaps in knowledge that need to be filled through further collaboration.
- Require the Company to develop large distribution investments such as the Grid Improvement Plan through an integrated distribution planning (IDP) or integrated systems & operations planning (ISOP) process moving forward.
- To the extent that Grid Improvement Plan projects are permitted deferred recovery, impose performance-based conditions on the recovery of such deferred amounts in rates, such as through adjustments to the weighted average cost of capital applied to the unamortized balance of deferred amounts.

Q. Does this conclude your testimony?

A. Yes.

CHAIR MITCHELL: And out of an abundance of caution and for purposes of the record, any -- any intervening party whose witness -- the testimony of whose witnesses was admitted during the consolidated hearing, that testimony will be copied into the record at this time. Again, just for purposes of clarity, it was admitted into this proceeding during the consolidated hearing and shall be copied into the record of this proceeding at this time.

MS. FORCE: Chair Mitchell? Margaret Force.

CHAIR MITCHELL: All right, Ms. Force.

MS. FORCE: I won't go --

CHAIR MITCHELL: You may proceed. Sorry.

MS. FORCE: I won't go through the details for Richard Baudino, assuming that your last statement covers his, but if you think there's a reason for me to go through it again, I will.

CHAIR MITCHELL: It covers Mr. Baudino.

MS. FORCE: Thank you.

(Whereupon, the prefiled direct testimony, Attachment A, and prefiled supplemental testimony of Richard A. Baudino was copied into the record as if given orally from the stand.)

(Whereupon, Exhibits RAB-1 through RAB-6, and Supplemental Exhibits RAB-1 through RAB-4 were admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1214

Proposed final 2/12/2020

In the Matter of	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Carolinas, LLC	)	**RICHARD A. BAUDINO**
For Adjustment of Rates and Charges Applicable	)	**ON BEHALF OF**
to Electric Service in North Carolina	)	**ATTORNEY GENERAL'S**
	)	**OFFICE**

I. QUALIFICATIONS AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a consultant with Kennedy and Associates.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Attachment A summarizes my expert testimony experience.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the North Carolina Attorney General's Office ("AGO").

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

A. The purpose of my Direct Testimony is to address the allowed return on equity, capital structure, and overall rate of return on rate base for the regulated electric operations of Duke Energy Carolinas, Inc. ("Duke Carolinas", or "Company"). I will also respond to the Direct Testimonies of Mr. Robert Hevert and Mr. Karl Newlin, witnesses for Duke Carolinas.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations are as follows.

Based on current financial market conditions, I recommend that the North Carolina Utilities Commission ("NCUC" or "Commission") adopt a 9.0% return on equity for Duke Carolinas in this proceeding. My recommendation is based primarily on the results of a Discounted Cash Flow ("DCF") model analysis and is conservatively high given the results. My DCF analysis incorporates my standard approach to estimating the investor required return on equity and utilizes the proxy group of 19 companies used by Duke Carolinas witness Hevert.

My cost of equity analysis also includes Capital Asset Pricing Model ("CAPM") analyses for additional information to further inform my recommendation to the Commission. I did not incorporate the results of the CAPM in my recommendation given the low cost of equity results being produced by this model at this time. Nonetheless, the CAPM results confirm the fact that the required ROE for regulated electric utilities continues to be low given the low interest rate environment that has prevailed in the economy for the last 10 or so years.

Finally, I also reviewed recent Commission-allowed ROEs presented by Mr. Hevert. Although I do not recommend that the Commission base its allowed ROE on the actions of other regulatory commissions, this review helped inform my recommended ROE of 9.0%.

I also recommend that the Commission reject Duke Carolinas' requested 53% equity ratio. The Company's requested equity ratio is higher than the average common equity ratio of the proxy group and would result in excessive rates to Duke Carolinas' North Carolina customers. Instead, I recommend the Commission approve the Company's December 2018 capital structure, which includes a common equity ratio of 51.5%. I also recommend that the Commission accept Duke Carolinas' requested cost of debt.

In Section IV of my testimony, I review Mr. Hevert's analysis of economic conditions in North Carolina and address his conclusion that these conditions support his recommended 10.5% ROE in this case. I disagree with Mr. Hevert's conclusion and explain why economic conditions in the state do not support his 10.5% ROE, but do support my recommended 9.0% ROE and capital structure.

In Section V, I respond to the testimony and ROE recommendation of the Company's witness Mr. Hevert. I will demonstrate that his recommended ROE of 10.5% overstates the current investor required return for a lower risk regulated electric company like Duke Carolinas. Today's financial environment of low interest rates has been deliberately and methodically supported by Federal Reserve policy actions since 2009. The Fed's further lowering of short-term interest rates three times in 2019 supports future expectations of lower interest rates through 2020. Moreover, Mr. Hevert ignored a significant portion of his ROE analyses from the DCF and CAPM models that showed much lower results than his recommended ROE range of 10.0% – 11.0% and his 10.5% recommended ROE.

II. FUNDAMENTALS OF SETTING THE ALLOWED RETURN ON EQUITY

Q. WHAT ARE THE MAIN GUIDELINES TO WHICH YOU ADHERE IN ESTIMATING THE COST OF EQUITY FOR A FIRM?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out by the United

States Supreme Court in *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) and *Bluefield W.W. & Improv. Co. v. Public Service Comm'n*, 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. DOES THE LEVEL OF INTEREST RATES AFFECT THE ALLOWED COST OF EQUITY, OR ROE, FOR REGULATED UTILITIES?

A. Yes. The common stock of regulated utilities is considered to be interest rate sensitive. This means that the cost of equity for regulated utilities tends to rise and fall with changes in interest rates. For example, as interest rates rise, the cost equity will also rise and vice versa when interest rates fall. This relationship is due in large part to the capital intensive nature of the utility industry, which relies heavily on both debt and equity to finance its regulated investments.

Q. DESCRIBE THE TREND IN INTEREST RATES OVER THE LAST 10 OR SO YEARS.

A. Since 2007 and 2008, the overall trend in interest rates in the U.S. and the world economy has been lower. This trend was precipitated by the 2007 financial crisis and severe recession that followed in December 2007. In response to this economic crisis, the Federal Reserve ("Fed") undertook an unprecedented series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets."[1]

Q. MR. BAUDINO, BEFORE YOU CONTINUE, PLEASE PROVIDE A BRIEF EXPLANATION OF HOW THE FED USES INTEREST RATES TO IMPROVE CONDITIONS IN THE FINANCIAL MARKETS.

A. Generally, the Fed uses monetary policy to implement certain economic goals. The Fed explained its monetary policy as follows:

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[1] https://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm

> Monetary policy in the United States comprises the Federal Reserve's actions and communications to promote maximum employment, stable prices, and moderate long-term interest rates--the three economic goals the Congress has instructed the Federal Reserve to pursue.
>
> The Federal Reserve conducts the nation's monetary policy by managing the level of short-term interest rates and influencing the overall availability and cost of credit in the economy.[2]

One of the Fed's primary tools for conducting monetary policy is setting the federal funds rate. The federal funds rate is the interest rate set by the Fed that banks and credit unions charge each other for overnight loans of reserve balances. Traditionally the federal funds rate directly influences short-term interest rates, such as the Treasury bill rate and interest rates on savings and checking accounts. The federal funds rate has a more indirect effect on long-term interest rates, such as the 30-Year Treasury bond and private and corporate long-term debt. Long-term interest rates are set more by market forces that influence the supply and demand of loanable funds.

Q. PLEASE CONTINUE WITH YOUR DISCUSSION OF THE FED'S QUANTITATIVE EASING PROGRAMS.

A. QE1 was implemented from November 2008 through approximately March 2010. During this time, the Fed cut its key Federal Funds Rate to nearly 0% and purchased $1.25 trillion of mortgage-backed securities and $175 billion of agency debt purchases. QE2 was implemented in November 2010 with the Fed announcing that it would purchase an additional $600 billion of Treasury

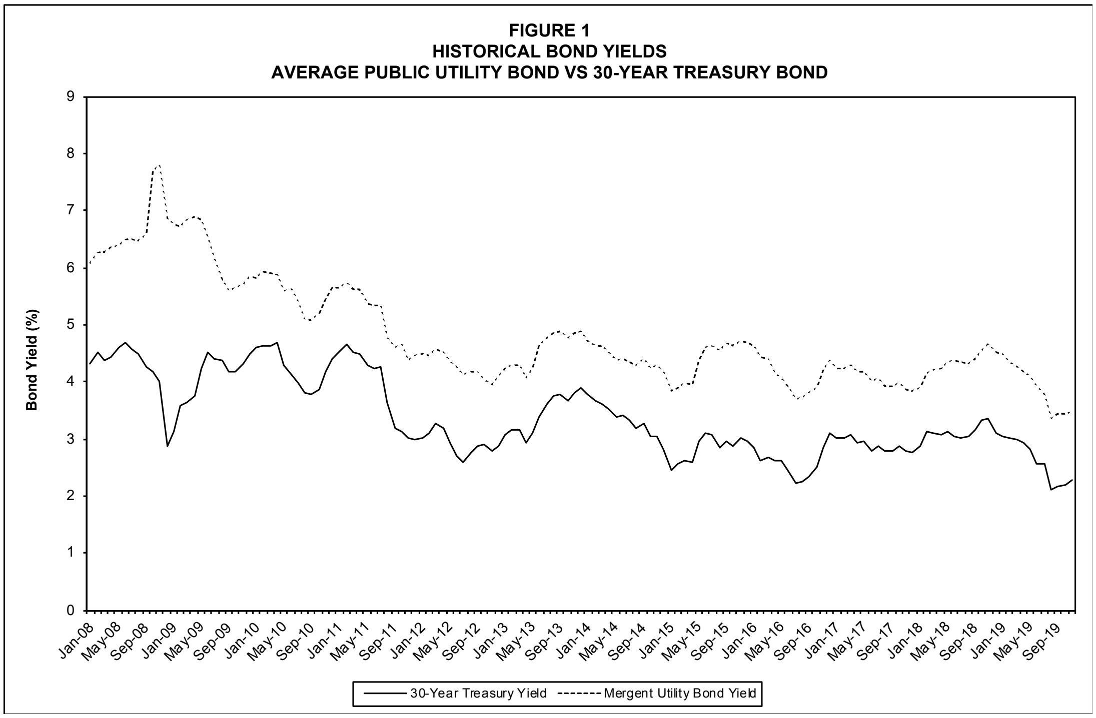
[2] https://www.federalreserve.gov/monetarypolicy.htm

securities by the second quarter of 2011.[3] Beginning in September 2011, the Fed initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist," was designed by the Fed to lower long-term interest rates and support the economic recovery. Finally, QE3 began in September 2012 with the Fed announcing an additional bond purchasing program of $40 billion per month of agency mortgage backed securities.

The Fed began to pare back its purchases of securities in the last few years. On January 29, 2014 the Fed stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Fed continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October.[4]

Figure 1 below presents a graph that tracks the 30-Year Treasury Bond yield and the Mergent average utility bond yield. The time period covered is January 2008 through December 2019.

[3] https://www.federalreserve.gov/newsevents/pressreleases/monetary20101103a.htm
[4] https://www.federalreserve.gov/newsevents/pressreleases/monetary20141029a.htm



The Fed's QE program and federal funds rate cuts were effective in lowering the long-term cost of borrowing in the United States. The 30-Year Treasury Bond yield declined from 5.11% in July 2007 to a low of 2.59% in July 2012. The average utility bond yield also fell substantially, from 6.28% in July 2007 to 4.12% in July 2012.

As of December 2019, these long-term interest rates are even lower than in 2012, with the 30-year Treasury Bond yield 2.30% and the average utility bond yield at 3.45%.

Q. PLEASE SUMMARIZE RECENT FED ACTIONS WITH RESPECT TO MONETARY POLICY.

A. In December 2015, the Fed began to raise its target range for the federal funds rate, increasing it to 1/4% to 1/2% from 0% to 1/4%. Since that time, the Fed increased the federal funds rate several more times, with the most recent increase announced on December 19, 2018 resulting in a federal funds rate range of 2.25% - 2.50%.

In 2019, however, the Fed reversed course and lowered the federal funds rate three times, with the rate now standing at 1.5% - 1.75%. In its press release dated January 29, 2020 the Fed stated the following:[5]

> Information received since the Federal Open Market Committee met in December indicates that the labor market remains strong and that economic activity has been rising at a moderate rate. Job gains have been solid, on average, in recent months, and the unemployment rate has remained low. Although household spending has been rising at a moderate pace, business fixed investment and exports remain weak. On a 12-month basis, overall inflation and inflation for items other than food and energy are running below 2 percent. Market-based measures of inflation compensation remain low; survey-based measures of longer-term inflation expectations are little changed.
>
> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee decided to maintain the target range for the federal funds rate at 1-1/2 to 1-3/4 percent. The Committee judges that the current stance of monetary policy is appropriate to support sustained expansion of economic activity, strong labor market conditions, and inflation returning to the Committee's symmetric 2 percent objective. The Committee will continue to monitor the implications of incoming information for the economic outlook, including global developments and muted inflation pressures, as it assesses the appropriate path of the target range for the federal funds rate.[6]

Q. WHAT ARE THE FED'S MOST RECENT ECONOMIC PROJECTIONS WITH RESPECT TO THE FEDERAL FUNDS RATE AND INFLATION?

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[5] https://www.federalreserve.gov/monetarypolicy/files/monetary20191211a1.pdf

[6] https://www.federalreserve.gov/newsevents/pressreleases/monetary20200129a.htm

A. The Fed provided certain economic projections that accompanied its December 11, 2019 press release showing the following:

- Projected federal funds rate of 1.6% for 2019 and 2020, 1.9% for 2021, and 2.1% for the longer run.
- Inflation running at 1.5% for 2019, 1.9% for 2020, and 2.0% for 2021 and 2022.[7]
- Real GDP growth of 1.9% for the longer run.

Q. WHY IS IT IMPORTANT TO UNDERSTAND THE FED'S ACTIONS SINCE 2008 AND THE EFFECT ON THE CURRENT COST OF CAPITAL IN THE ECONOMY GENERALLY AND FOR REGULATED UTILITIES SPECIFICALLY?

A. The Fed's monetary policy actions since 2008 were deliberately undertaken to lower interest rates and support economic recovery. The U.S. economy is still in a low interest rate environment. This environment has affected the common stocks of regulated utilities, which, as I mentioned earlier, are interest rate sensitive. Lower interest rates support lower required ROEs for regulated utilities.

Q. ARE CURRENT INTEREST RATES INDICATIVE OF INVESTOR EXPECTATIONS REGARDING THE FUTURE DIRECTION OF INTEREST RATES?

[7] https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20191211.pdf

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Morin pointed out in *New Regulatory Finance:*

> A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information.[8]

Dr. Morin also noted the following:

> There is extensive literature concerning the prediction of interest rates. From this evidence, it appears that the no-change model of interest rates frequently provides the most accurate forecasts of future interest rates while at other times, the experts are more accurate. Naïve extrapolations of current interest rates frequently outperform published forecasts. The literature suggests that on balance, the bond market is very efficient in that it is difficult to consistently forecast interest rates with greater accuracy than a no-change model. The latter model provides similar, and in some cases, superior accuracy than professional forecasts.[9]

It is important to realize that investor expectations of changes in future interest rates, if any, are likely already embodied in current securities prices, which include debt securities and stock prices. Moreover, the current low interest rate environment still favors lower risk regulated utilities.

Q. YOU MENTIONED THAT THE REQUIRED COST OF EQUITY FOR REGULATED UTILITIES TENDS TO FOLLOW THE DIRECTION OF INTEREST RATES. COULD YOU ILLUSTRATE THIS RELATIONSHIP FOR THE COMMISSION?

[8] Morin, Roger A., *New Regulatory Finance,* Public Utilities Reports, Inc. (2006) at 279.
[9] *Id*. at 172.

A. Yes. Table 1 below presents data from Mr. Hevert's Exhibit RBH-5 and presents the average yearly yield on the 30-year Treasury Bond and the yearly average allowed ROE for electric companies from 2000 through August 12, 2019. Table 1 shows that as the long-term Treasury Bond yield has fallen since 2000, allowed ROEs for electric utilities followed suit, although the decline in ROEs has been less than that for the 30-year Treasury Bond. The Premium column in Table 1 shows the difference between allowed ROEs and the 30-Year Treasury yield. In 2007, for example, the premium of allowed ROEs over Treasury yields was 5.45%. The premium has grown significantly since 2007, rising to almost 7.0% in 2012 and 2016 and falling to 6.48% through August 2019. The purpose of Table 1 is to demonstrate the interest rate sensitivity of regulated utility ROEs to the general level of interest rates, not to recommend that the Commission follow this relationship or rely on the commission-allowed ROEs from other states. I shall demonstrate later in my testimony that current market data shows that the investor required ROEs for regulated electric utilities are lower than recent Commission allowed ROEs.

Table 1
Allowed ROEs and
30-Year Treasury Yields

Year	Allowed ROE	30-Year T-Bond	Premium
2000	11.58%	6.07%	5.51%
2001	11.07%	5.59%	5.48%
2002	11.21%	5.42%	5.79%
2003	10.96%	4.94%	6.03%
2004	10.81%	5.06%	5.75%
2005	10.51%	4.71%	5.81%
2006	10.34%	4.83%	5.52%
2007	10.31%	4.87%	5.45%
2008	10.37%	4.54%	5.83%
2009	10.52%	4.02%	6.50%
2010	10.29%	4.33%	5.96%
2011	10.19%	4.13%	6.06%
2012	10.01%	3.03%	6.98%
2013	9.81%	3.21%	6.60%
2014	9.75%	3.51%	6.24%
2015	9.60%	2.90%	6.70%
2016	9.60%	2.62%	6.97%
2017	9.68%	2.82%	6.86%
2018	9.56%	2.99%	6.56%
2019	9.57%	3.10%	6.48%

Q. HOW DOES THE INVESTMENT COMMUNITY REGARD THE REGULATED ELECTRIC UTILITY INDUSTRY AS A WHOLE?

A. The Value Line Investment Survey noted the following in its review of the Electric Utility (West) Industry dated January 24, 2020:

> "The year that just ended was excellent for most stocks in the Electric Utility Industry. According to data provided by the Edison Electric Institute (a group representing investor-owned utilities), in 2019 the median total return of 40 electric stocks was 25.1%. Although this fell short of the 33.1% total return of the S&P 500 Index, this was still a respectable showing, particularly on a risk-adjusted basis. Most of the equities in this group produced a total return that exceeded 10%.
>
> * * *
>
> Why did most utility stocks fare well? Interest rates had something to do with this. As 2019 began, there was concern among utility investors that the Federal Reserve might continue

> raising interest rates after doing so three times in 2018. This did not happen; in fact, the Fed reversed its course and cut rates three times last year. With the interest rates on fixed-income investments falling from an already-low level, this made the dividend yields of electric utility equities relatively more attractive. By reaching for yield, investors drove up the prices of most utility issues.
>
> * * *
>
> Following the stellar showing of most stocks in this group in 2019, the group is valued expensively (even after the aforementioned dip in early 2020). Most of these equities have a relative price-earnings ratio above 1.00, and not by just a slight amount. The dividend yield of this group is just 3.1%. Although this figure is roughly one percentage point above the median for dividend paying stocks covered in The Value Line Investment Survey, it is low, by historical standards. For most equities in the Electric Utility Industry, the recent price is well within the 3- to 5-year Target Price Range. This is another example of the group's lofty valuation. Of course, having a high valuation does not mean this cannot become even higher—the performance of most of these stocks in 2019 illustrates this—but we think investors should not count on a repeat in 2020."

My position regarding the current low interest rate environment is consistent with Value Line's report on the electric utility industry. Lower interest rates will mean lower allowed ROEs and this is a positive development for utility ratepayers. Further, lower interest rates translate into lower debt costs and a lower cost of capital applied to the utility's rate base. Again, this is a positive trend for ratepayers' cost of electricity.

Q. THE EDISON ELECTRIC INSTITUTE ("EEI") PUBLISHES QUARTERLY REVIEWS OF THE INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY. PLEASE SUMMARIZE EEI'S FINDINGS WITH RESPECT TO CREDIT RATINGS, RISKS, AND VALUATIONS FOR THE ELECTRIC UTILITY INDUSTRY.

A. EEI's recent 3rd Quarter 2019 summary of the Standard and Poor's Utility Credit Ratings showed the following:

- The industry average credit rating was BBB+.
- 58% of the 45 utilities followed by EEI had credit ratings of BBB/BBB+.
- 27% had a credit rating of A-.

EEI's analysis shows that the investor-owned electric utility industry had strong and stable credit metric through the 3rd Quarter of 2019.

EEI's *Q3 2019 Financial Update*, page 5, noted the following regarding whether electric utility valuations could rise further from their present levels:

> "Wall Street analysts generally view utility stock valuations as high when measured by price/earnings (PE) ratios relative to the S&P 500 and to history. One reason for this is the very low level of interest rates both in the U.S. and overseas. The U.S. 10-year Treasury yield was about 6% in the late 1990s, more than triple today's level, while bond markets in Europe and Japan sport widespread negative yields. *Another reason is the strong fundamentals that underpin prospects for total returns in excess of 8% (5% from earnings growth and 3% from the dividend). Given this outlook, the view seems to be that utilities offer enough value to lift multiples higher still, particularly if global economic growth turns down and interest rates fall to new lows*." (emphasis added)

EEI's publication also noted the following with respect to interest rates:

> "A sharp rise in interest rates is widely seen as the biggest macro threat facing utility investors. *Although that has been said for years and interest rates just seem to fall.* Inflation held near 2% throughout 2018 even as the economy roared and hasn't moved this year either. The main risk to the very long-lived economic expansion seems to be weakness rather than red-hot growth.
>
> Analysts note that the impact of rising rates would be on stock prices rather than earnings. Higher rates can translate into higher allowed ROEs and improved pension funding. Many companies have embedded low-cost debt from years of low

> rates, and interest rates could rise while remaining very low by historical standards." (emphasis added)

I underscore to the Commission EEI's statements regarding (1) prospects for total returns in excess of 8%, and (2) the stability of the current low interest rate environment despite years of predictions of higher interest rates. It also shows that the strong credit ratings for regulated electric companies are fully consistent with lower ROEs and lower cost of debt. In my view, these points support my recommended cost of equity for Duke Carolinas of 9.0% as being consistent with investor expectations and current market conditions.

Q. WHAT ARE THE CURRENT CREDIT RATINGS FOR DUKE ENERGY CAROLINAS?

A. Moody's long-term issuer rating for Duke Carolinas is A1. Within Moody's A rating category, A1 is the highest rating (A3 being the lowest). Standard and Poor's ("S&P") credit rating is A-, which is the lowest rating in S&P's A category (A+ being the highest). The ratings outlook from both Moody's and S&P is stable. On November 20, 2019 S&P affirmed the credit ratings of Duke Energy and its operating utility subsidiaries, including Duke Carolinas, and revised its ratings outlook to stable from negative.

Moody's October 19, 2019 Credit Opinion for Duke Carolinas noted the following:[10]

> "Our view of Duke Energy Carolinas' (Duke Carolinas) credit reflects its low business and operating risk profile and historically supportive regulatory environments in both North and South Carolina. Our view is tempered by the utility's weaker

[10] Moody's Credit Opinion was provided in response to the North Carolina Public Staff Data Request No. 38, Item No. 38-5.

> financial credit metrics, but also considers the company's position as the largest subsidiary within the Duke Energy Corporation family, making up about a third of its rate base. Our view recognizes the benefits of scale and the potential for operational efficiencies that are enabled by joint management with affiliate Duke Energy Progress."

Duke Carolina's credit strengths enumerated by Moody's are:

- Credit supportive regulatory environments
- Approved recovery for the majority of coal ash related expenditures
- Growing service territories
- Position as part of Duke Energy utility system

Duke Carolinas' credit challenges according to Moody's are:

- High capital expenditures
- Increasing regulatory uncertainty surrounding coal ash remediation spending
- Financial metrics are under pressure

Q. DID DUKE ENERGY, THE HOLDING COMPANY FOR DUKE ENERGY CAROLINAS, PROVIDE INFORMATION TO ITS INVESTORS THAT IS RELEVANT TO THE COMMISSION'S EVALUATION OF THE ALLOWED RATE OF RETURN FOR DUKE CAROLINAS?

A. Yes. Please refer to Exhibit RAB-1, which contains excerpts from Duke Energy's presentation entitled *Duke Energy Winter Update January 2020*. I obtained this presentation from Duke Energy's web site.

Page 2 of Exhibit RAB-1 provides Duke Energy's explanation of the recent settlement agreement regarding coal ash costs, which was entered into with the North Carolina Department of Environmental Quality and other parties represented by the Southern Environmental Law Center on December 31, 2019. Duke noted that the settlement provided "clarity on closure method and costs."

Page 3 of Exhibit RAB-1 shows Duke Energy's presentation of its "attractive risk-adjusted total shareholder return" of 8% – 10%. This total return consists of a dividend yield of 4.2% and a growth rate of 4% – 6%. I note that my recommended ROE for Duke Carolinas of 9.0% falls in the middle of this range. Mr. Hevert's recommended ROE of 10.5% is well above the total shareholder return range cited by Duke Energy.

Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE OVERALL RISKINESS OF DUKE CAROLINAS?

A. Both Moody's and S&P's recent credit rating reports on Duke Carolinas indicate that although the Company is facing risks associated with the ultimate disposition of coal ash costs as well as elevated construction spending, those risks are tempered by the Company's low risk regulated business and its low operating risk. Taken together, Duke Carolinas has credit ratings that are slightly above average compared to the average S&P credit rating of BBB+ for the electric utilities covered by the aforementioned EEI publication.

With respect to the return on equity in this case, Duke Carolinas' credit standing indicates that its allowed ROE should be based on the average results of the proxy group that Mr. Hevert and I use in this case. There is no basis for the Company's allowed ROE to be higher than the proxy group results.

III. DETERMINATION OF RETURN ON EQUITY

Q. PLEASE DESCRIBE THE METHODS YOU EMPLOYED IN ESTIMATING YOUR RECOMMENDED RETURN ON EQUITY FOR DUKE CAROLINAS.

A. I employed a Discounted Cash Flow ("DCF") analysis using a proxy group of 19 regulated electric utilities as selected by Mr. Hevert. In my opinion, they form a reasonable basis for estimating the investor required return on equity for Duke Carolinas. I also employed Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data. Although I primarily relied on the DCF results for my recommended 9.0% ROE for the Company, the results from the CAPM tend to support the reasonableness of my recommendation.

Q. DESCRIBE THE PROXY GROUP YOU EMPLOYED TO ESTIMATE THE COST OF EQUITY FOR DUKE CAROLINAS.

A. In this case, I chose to use the same proxy group that Mr. Hevert used in his ROE analyses. Mr. Hevert discussed his approach to developing his recommended proxy group on pages 23 through 24 of his Direct Testimony. Mr. Hevert's selection criteria are generally reasonable and include regulated electric utilities that have investment grade credit ratings from S&P. Using the same proxy group as Mr. Hevert also has the advantage of eliminating a source of disagreement between our respective ROE analyses and furnishes the

Commission with a consistent group of companies to compare and evaluate our ROE results and recommendations.

Discounted Cash Flow ("DCF") Model

Q. PLEASE DESCRIBE THE BASIC DCF APPROACH.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: *V = asset value*

R = yearly cash flows

r = discount rate

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I typically employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {D_1}/{P_0} + g$$

Where: D_1 *= the next period dividend*

P_0 *= current stock price*

g *= expected growth rate*

k *= investor-required return*

Embodied in this formula, it is assumed that "k" reflects the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. WHAT WAS YOUR FIRST STEP IN DETERMINING THE DCF RETURN ON EQUITY FOR THE PROXY GROUP?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from August 2019 through January 2020. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the proxy group is 2.88%. These calculations are shown in Exhibit RAB-2.

Q. HAVING ESTABLISHED THE AVERAGE DIVIDEND YIELD, HOW DID YOU DETERMINE THE INVESTORS' EXPECTED GROWTH RATE FOR THE PROXY GROUP?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

For my analysis in this proceeding, I used three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and Yahoo! Finance.

Q. PLEASE BRIEFLY DESCRIBE VALUE LINE, ZACKS, AND YAHOO! FINANCE.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Plus Edition. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth. I obtained Zacks' earnings growth forecasts from its web site.

Like Zacks, Yahoo! Finance also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from the Yahoo! Finance web site.

Q. WHY DID YOU RELY ON ANALYSTS' FORECASTS IN YOUR ANALYSIS?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for future dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. PLEASE EXPLAIN HOW YOU USED ANALYSTS' DIVIDEND AND EARNINGS GROWTH FORECASTS IN YOUR CONSTANT GROWTH DCF ANALYSIS.

A. Columns (1) through (4) of Exhibit RAB-3 shows the forecasted dividend and earnings growth rates from Value Line and the earnings growth forecasts from Zacks and Yahoo! Finance for the companies in the proxy group. It is important to include dividend growth forecasts in the DCF model since the model calls for forecasted cash flows and Value Line is the only source of which I am aware that forecasts dividend growth.

Q. HOW DID YOU PROCEED TO DETERMINE THE DCF RETURN OF EQUITY FOR THE PROXY GROUP?

A. To estimate the expected dividend yield (D_1), the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

Exhibit RAB-3 presents my standard method of calculating dividend yields, growth rates, and return on equity for the proxy group. The DCF Return on Equity Calculation section shows the application of each of four growth rates I used in my analysis to the current group dividend yield of 2.88% to calculate the expected dividend yield. I then added the expected growth rates to the expected dividend yield. My DCF return on equity was calculated using two different methods. Method 1 uses the Average Growth Rates shown in the upper section of Exhibit RAB-3 and Method 2 utilizes the median growth rates shown in that section.

Q. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A. The results for Method 1 range from 8.46% to 8.73% and the results for Method 2 range from 8.21% to 9.02%. The average results for Methods 1 and 2 are 8.54% and 8.67%, respectively, for the proxy group.

Capital Asset Pricing Model

Q. BRIEFLY SUMMARIZE THE CAPITAL ASSET PRICING MODEL ("CAPM") APPROACH.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: *K* = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's risk premium can be determined by multiplying its beta by the market risk premium. Its total return may then be estimated by adding the risk-free rate to that risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns.

Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. IN GENERAL, ARE THERE CONCERNS REGARDING THE USE OF THE CAPM IN ESTIMATING THE RETURN ON EQUITY?

A. Yes. There is some controversy surrounding the use of the CAPM and its accuracy regarding expected returns. There is substantial evidence that beta is not the primary factor for determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk. Dr. Burton Malkiel, author of *A Random Walk Down Wall Street* noted the following in his best-selling book on investing:

> Second, as Professor Richard Roll of UCLA has argued, we must keep in mind that it is very difficult (indeed probably impossible) to measure beta with any degree of precision. The S&P 500 Index is not "the market." The Total Stock Market contains many thousands of additional stocks in the United States and thousands more in foreign countries. Moreover, the total market includes bonds, real estate, commodities, and assets of all sorts, including one of the most important assets any of us has - the human capital built up by education, work, and life experience. Depending on exactly how you measure "the market" you can obtain very different beta values.[11]

Pratt and Grabowski also stated the following with respect to the CAPM:[12]

> Even though the capital asset pricing model (CAPM) is the most widely used method of estimating the cost of equity capital, the accuracy and predictive power of beta as the sole measure of risk have increasingly come under attack. As a result, alternative measures of risk have been proposed and tested. That is, despite

[11] *A Random Walk Down Wall Street*, Burton G. Malkiel, page 218, 2019 edition.

[12] *Cost of Capital*, Shannon Pratt and Roger Grabowski, 5th Edition, page 288, published by Wiley.

> its wide adoption, academics and practitioners alike have questioned the usefulness of CAPM in accurately estimating the cost of equity capital and the use of beta as a reliable measure of risk.

As a practical matter, there is substantial judgment involved in estimating the required market return and market risk premium. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500. However, as Dr. Malkiel pointed out, this is a limited source of information with respect to estimating the investor's required return for all investments. In practice, the total market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

In the final analysis, a considerable amount of judgment must be employed in determining the market return and expected risk premium elements of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating investor-required returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. HOW DID YOU ESTIMATE THE MARKET RETURN AND MARKET RISK PREMIUM OF THE CAPM?

A. I used two approaches to estimate the market risk premium portion of the CAPM equation. One approach uses the expected return on the market and is forward-looking. The other approach employs an historical risk premium based on actual stock and bond returns from 1926 through 2018.

Q. PLEASE DESCRIBE YOUR FORWARD-LOOKING APPROACH TO ESTIMATING THE MARKET RISK PREMIUM.

A. The first source I used was the Value Line Investment Analyzer Plus Edition, for January 10, 2020. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual returns on page 2 of Exhibit RAB-4. I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 10.61% to 11.61%. The average of these market returns is 11.11%.

Q. WHY DID YOU USE MEDIAN GROWTH RATE ESTIMATES RATHER THAN THE AVERAGE GROWTH RATE ESTIMATES FOR THE VALUE LINE COMPANIES?

A. Using median growth rates is likely a more accurate approach to estimating the central tendency of Value Line's large data set compared to the average growth rates. Average earnings and book value growth rates may be unduly influenced by very high or very low 3–5-year growth rates that are unsustainable in the long run. For example, Value Line's Statistical Summary shows both the highest and lowest value for earnings and book value growth forecasts. For earnings growth, Value Line showed the highest earnings growth forecast to be 92.5% and the lowest growth rate to be -13.5%. With respect to book value, the highest growth rate was 84% and the lowest was a -27.5%. None of these growth rate projections is compatible with long-run growth prospects for the market as a whole. The median growth rate is not influenced by such extremes because it represents the middle value of a very wide range of earnings growth rates.

Q. PLEASE CONTINUE WITH YOUR MARKET RETURN ANALYSIS.

A. I also considered a supplemental check to the Value Line projected market return estimates. Duff and Phelps compiled a study of historical returns on the stock market in its *2019 Valuation Handbook - U.S. Guide to Cost of Capital*, which is now part of its Cost of Capital Navigator subscription service. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit RAB-5 presents the calculation of the market returns and market risk premiums using the historical data from Duff and Phelps.

Q. PLEASE EXPLAIN HOW THIS HISTORICAL RISK PREMIUM IS CALCULATED.

A. Exhibit RAB-5 shows the arithmetic average of yearly historical stock market returns over the historical period from 1926 – 2018. The average annual income return for 20-year Treasury bond is subtracted from these historical stock returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The resulting historical market risk premium is 6.9%.

Q. DID YOU ADD AN ADDITIONAL MEASURE OF THE HISTORICAL RISK PREMIUM IN THIS CASE?

A. Yes. Duff and Phelps reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio.[13] Duff and Phelps noted that this growth in the P/E ratio for stocks was subtracted out of the historical risk premium to arrive at an adjusted "supply side" historical arithmetic market risk premium is 6.14%, which I have also included in Exhibit RAB-5.

Q. HOW DID YOU DETERMINE THE RISK FREE RATE?

A. I used two different measures for the risk-free rate. The first measure is the average 30-year Treasury Bond yield for the six-month period from August 2019 through January 2020. This represents a current measure of the risk-free rate based on actual current Treasury yields, which is 2.21%.

The second measure comes from Duff and Phelps' most recent "normalized" risk-free rate of September 30, 2019.[14] Duff and Phelps developed this normalized risk-free rate using its measure of the "real risk free

[13] *2019 Cost of Capital: Annual U.S. Guidance and Examples,* Duff and Phelps, Cost of Capital Navigator, Chapter 3, pp. 45 - 47.

[14] https://www.duffandphelps.com/insights/publications/valuation/us-normalized-risk-free-effective-september-30-2019

rate" and expected inflation. The Duff and Phelps normalized risk-free rate is 3.0%.

Q. PLEASE SUMMARIZE YOUR CALCULATED MARKET RISK PREMIUM ESTIMATES WITH THE FORWARD-LOOKING DATA FROM VALUE LINE AND THE HISTORICAL DUFF AND PHELPS EQUITY RISK PREMIUMS.

A. My market risk premiums from Exhibits RAB-4 and RAB-5 are as follows:

- Forward-looking risk premiums 8.11% - 8.90%
- Historical risk premium 6.14% - 6.90%

By way of comparison, Duff and Phelps currently recommends an equity risk premium of 5.5%, which resulted in a base U.S. cost of capital estimate of 8.5%. Based on this comparison, my range of equity risk premium estimates are certainly not conservative or understated.

Q. HOW DID YOU DETERMINE THE VALUE FOR BETA?

A. I obtained the betas for the companies in the proxy group from most recent Value Line reports. The average of the Value Line betas for the proxy group is 0.56.

Q. PLEASE SUMMARIZE THE CAPM RESULTS.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 7.20% – 7.55%. Using historical risk premiums, the CAPM results range from 5.66% - 6.87%.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE RESULTS OF THE CAPM AT THIS TIME?

A. Yes. The CAPM is currently producing results that are low under a reasonable range of equity risk premium estimates. Even if I had used Value Line's highest expected market return of 12.21% from Exhibit RAB-4 and the Duff and Phelps normalized risk-free rate, the CAPM result would have been:

$$CAPM = 3.0\% + .57\ (12.21\% - 3.0\%) = 8.25\%$$

This represents the top of the range for the CAPM, which is still substantially below my average DCF estimates. At this point, I cannot recommend that the Commission place substantial weight on the CAPM. Although Mr. Hevert presented CAPM results that are higher, his analysis is fraught with problems that I will discuss at length later in my testimony.

ROE Conclusions and Recommendations

Q. PLEASE SUMMARIZE THE COST OF EQUITY RESULTS FOR YOUR DCF AND CAPM ANALYSES.

A. Table 2 below summarizes my return on equity results using the DCF and CAPM for the proxy group of companies.

Table 2
SUMMARY OF ROE ESTIMATES

DCF Methodology	
Average Growth Rates	
- High	8.73%
- Low	8.46%
- Average	8.54%
Median Growth Rates:	
- High	9.02%
- Low	8.21%
- Average	8.67%
CAPM Methodology	
Forward-lookng Market Return:	
- Current 30-Year Treasury	7.20%
- D&P Normalized Risk-free Rate	7.55%
Historical Risk Premium:	
- Current 30-Year Treasury	5.66% - 6.08%
- D&P Normalized Risk-free Rate	6.45% - 6.87%

Q. DID YOU REVIEW RECENTLY ALLOWED EQUITY RETURNS FROM REGULATORY COMMISSIONS?

A. Yes. My Table 1 shows that the average commission allowed ROEs and 30-Year Treasury Bond yields for 2016, 2017, 2018, and 2019 were as follows:

- 2016: ROE - 9.60%, 30-Year Treasury - 2.62%
- 2017: ROE - 9.68%, 30-Year Treasury - 2.82%
- 2018: ROE - 9.56%, 30-Year Treasury - 2.99%
- 2019: ROE - 9.57%, 30-Year Treasury - 3.10%

I note that the average 30-year Treasury yields in these years were significantly higher than current long-term Treasury yields. Exhibit RAB-4 shows that the most recent six-month average 30-year Treasury Bond yield is only 2.21%, compared to the average yield in 2019 of 3.10%. With long-term Treasury yields so much lower now, it makes sense that the allowed ROE for regulated electric companies should decline as well.

Q. WHAT IS YOUR RECOMMENDED RETURN ON EQUITY FOR DUKE CAROLINAS?

A. Based on my analysis in this case and the decline in long-term interest rates in the economy generally, I recommend that the Commission adopt a 9.00% return on equity for Duke Carolinas.

Q. PLEASE EXPLAIN HOW YOU ARRIVED AT YOUR RECOMMENDATION.

A. I began with the average DCF ROE results in Table 2 and also considered the top end of my DCF range, which is 9.02%. In recommending 9.0%, I recognize that recent Commission allowed returns are higher than my DCF results. However, I do not recommend that the Commission base its allowed ROE on the average allowed ROEs in other states. Such an approach would not be based on the specific evidence and circumstances presented in this case. Nevertheless, my recommendation of 9.0% is reasonably close to recently allowed ROEs and is fully based on the market evidence and analysis I reviewed.

I also considered the comments from the Value Line Investment Survey I quoted in Section II of my Direct Testimony, which stated that valuations for utility stocks are already within their forecasted levels for the 2022 – 2024 time period. My recommendation of 9.0% allows for some risk of declines in the stock prices of the companies in the proxy group given the current high valuations and the "reach for yield" by investors mentioned by Value Line.

Q. DID YOU ACCEPT THE COMPANY'S REQUESTED CAPITAL STRUCTURE?

A. No. Duke Carolinas requested that the Commission grant a 53% common equity ratio in this proceeding. However, the Company's December 31, 2018 equity ratio is 51.5% with a long-term debt ratio of 48.5%. The 51.5% actual equity ratio is fully consistent with and supportive of the Company's current credit ratings. Company witness Newlin, who submitted testimony on capital structure, did not provide any analysis showing that a 53% equity was necessary or prudent to support the Company's credit ratings or that a 51.5% equity would harm the Company's credit profile.

Q. HOW DOES DUKE CAROLINAS' 2018 COMMON EQUITY RATIO COMPARE WITH THE COMMON EQUITY RATIOS OF THE PROXY GROUP?

A. Table 3 below shows the 2018 common equity ratios for each company in the proxy group as well as the average common equity ratio for the group.

Table 3
Proxy Group 2018 Common Equity Ratios

ALLETE, Inc.	60.1%
Alliant Energy Corporation	46.7%
Ameren Corp.	48.8%
American Electric Power Co.	46.8%
Avangrid, Inc.	73.8%
CMS Energy Corporation	30.7%
DTE Energy Company	45.8%
Evergy, Inc.	60.0%
Hawaiian Electric	51.7%
NextEra Energy, Inc.	56.0%
Northwestern Corporation	47.8%
OGE Energy Corp.	58.0%
Otter Tail Corporation	55.3%
Pinnacle West Capital Corp.	53.0%
PNM Resources, Inc.	38.6%
Portland General Electric Company	53.5%
Southern Company	37.6%
WEC Energy Group	49.4%
Xcel Energy Inc.	43.6%
Average	50.4%

Source: Value Line Investment Survey

The average common equity ratio for the proxy group is 50.4%, lower than Duke Carolinas' 2018 equity ratio. This indicates that the Company has slightly less financial risk from debt in its capital structure than the proxy group. It also demonstrates the reasonableness of using Duke Carolinas' 2018 capital structure for ratemaking purposes in this docket.

Q. WHAT IS YOUR RECOMMENDED WEIGHTED COST OF CAPITAL FOR DUKE CAROLINAS?

A. My recommended weighted cost of capital is presented in Table 4. I used the Company's 2018 capital structure, its 2018 cost of debt of 4.51%, and my recommended ROE of 9.0%. The weighed cost of capital is 6.82%.

Table 4 Recommended Weighted Cost of Capital			
	Capital Ratio	Component Costs	Weighted Avg Cost
Long Term Debt	48.50%	4.51%	2.19%
Common Equity	51.50%	9.00%	4.64%
Total Capital	100.00%		6.82%

IV. ECONOMIC CONDITIONS IN NORTH CAROLINA

Q. PLEASE DISCUSS MR. HEVERT'S ANALYSIS OF ECONOMIC CONDITIONS IN NORTH CAROLINA.

A. Mr. Hevert presented his analysis of North Carolinas' economic conditions beginning on page 53 of his Direct Testimony. As a preliminary matter, Mr. Hevert set forth the Commission's considerations with respect to balancing the interests of investors and ratepayers in setting the allowed ROE for North Carolina utilities.[15] With respect to his economic analysis, Mr. Hevert reached the following main conclusions:[16]

- North Carolinas' unemployment rate has fallen by two-thirds since its peak in 2009-2010 and as of June 2019 the unemployment rate stood at 4.20%, which is higher than the national average of 3.70%.
- The unemployment rate in the counties served by Duke Carolinas is "approximately" equal to the North Carolina average unemployment rate.

[15] State of North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, October 23, 2013, at 34 - 35; Dominion Remand Order, Docket No. E-22, Sub 479 at 26.

[16] Refer to pages 61 through 63 of Mr. Hevert's Direct Testimony.

- North Carolinas' Gross Domestic Product ("GDP") is "highly correlated" with national GDP.
- Median household income has grown in North Carolina and has grown at a rate consistent with the national average median income. Also, the overall cost of living in North Carolina is below the national average.
- Residential electricity rates have been approximately 8.28% below the national average over the last 15 years.
- Based on his analysis, Mr. Hevert opined that his recommended 10.5% ROE is "fair and reasonable to DE Carolinas, its shareholders, and its customers in light of the effect of those changing economic conditions."

Q. PLEASE PRESENT YOUR CONCLUSIONS WITH RESPECT TO THE STUDY CONDUCTED BY MR. HEVERT.

A. My conclusions are:

- Although the decline in unemployment rates for North Carolina and the counties that Duke Carolinas serves are correlated with the national average, they are higher than the national average.
- Although the growth in median income in North Carolina is correlated with the national average, the median income in North Carolina and the counties served by Duke Carolinas is significantly lower than the national average.
- Duke Carolinas' lower than average residential rates and North Carolinas' lower than average cost of living do not justify the Company's excessive requested ROE and overall cost of capital.

Q. PLEASE ADDRESS YOUR CONCLUSION WITH RESPECT TO UNEMPLOYMENT RATES FOR NORTH CAROLINA AND THE UNITED STATES AS A WHOLE.

A. As Mr. Hevert pointed out in his Direct Testimony, North Carolinas' unemployment rate fell as the overall U.S. unemployment rate fell, although North Carolinas' unemployment rate was 0.50% higher as of June 2019. As of December 2019, the U.S. unemployment rate was 3.50% and the North Carolina unemployment rates was 3.70%, according to the U.S. Bureau of Labor Statistics.[17] I also reviewed Mr. Hevert's data supporting his unemployment analysis in Chart 4 on page 56 of his Direct Testimony. Table 5 below presents Mr. Hevert's monthly unemployment rate data from January 2018 through June 2019.

[17] The North Carolina unemployment rate was preliminary as of the preparation of my Direct Testimony.

Table 5
Unemployment Rate Comparison

	U.S. Unemployment Rate	N.C. Unemployment Rate	Difference
Jan-2018	4.10	4.20	0.10
Feb-2018	4.10	4.20	0.10
Mar-2018	4.00	4.10	0.10
Apr-2018	3.90	4.00	0.10
May-2018	3.80	4.00	0.20
Jun-2018	4.00	3.90	(0.10)
Jul-2018	3.90	3.80	(0.10)
Aug-2018	3.80	3.70	(0.10)
Sep-2018	3.70	3.70	-
Oct-2018	3.80	3.70	(0.10)
Nov-2018	3.70	3.70	-
Dec-2018	3.90	3.70	(0.20)
Jan-2019	4.00	3.80	(0.20)
Feb-2019	3.80	3.90	0.10
Mar-2019	3.80	4.00	0.20
Apr-19	3.60	4.00	0.40
May-19	3.60	4.10	0.50
Jun-19	3.70	4.20	0.50

Source: Mr. Hevert's work papers

Note that the "Difference" column presents the difference between the North Carolina unemployment rate and the U.S. unemployment rate. In January 2018, for example, the North Carolina unemployment rate was higher than the national average, resulting in positive 0.10 difference. From July 2018 through January 2019 North Carolinas' unemployment rate was lower than the national average, then went back above the national average in February 2019. North Carolinas' unemployment rate has declined since Mr. Hevert filed his testimony in this case, but is slightly higher than the U.S. unemployment rate.

Q. PLEASE COMMENT ON THE DIFFERENCE IN MEDIAN INCOME BETWEEN THE NATIONAL AVERAGE AND NORTH CAROLINA.

A. The data underlying Mr. Hevert's median income comparison shows that North Carolina's median income has been persistently and significantly below the

U.S. median income during the entire study period. Table 6 below presents U.S. and North Carolina median income and the percentage difference between them. This data was taken from Mr. Hevert's work papers.

Table 6
Median Income Comparison

Year	U.S. Median Income	N.C. Median Income	Difference
2018	63,179	53,369	-15.5%
2017	61,136	49,547	-19.0%
2016	59,039	53,764	-8.9%
2015	56,516	50,797	-10.1%
2014	53,657	46,784	-12.8%
2013	53,585	46,337	-13.5%
2012	51,017	41,553	-18.6%
2011	50,054	45,206	-9.7%
2010	49,276	43,830	-11.1%
2009	49,777	41,906	-15.8%
2008	50,303	42,930	-14.7%
2007	50,233	43,513	-13.4%
2006	48,201	39,797	-17.4%
2005	46,326	42,056	-9.2%

Source: Mr. Hevert's work papers

Table 6 shows that the difference between the North Carolina and U.S. median income levels has grown from -8.9% in 2016 to -19.0% in 2017 and -15.5% in 2018. These differences underscore the importance of setting the allowed ROE and the overall cost of capital as low as possible while still satisfying the legal requirements of *Hope* and *Bluefield* and the North Carolina Supreme Court's finding with respect to return on equity.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT ON DUKE CAROLINAS NORTH CAROLINA RATEPAYERS FROM MR. HEVERT'S RECOMMENDED 10.5% ROE AND THE COMPANY'S

PROPOSED 53% EQUITY RATIO COMPARED TO YOUR RECOMMENDATION?

A. The rate impact on North Carolina customers is substantial. Exhibit RAB-6 presents my calculation of the increased revenue requirement from the Company's requested ROE of 10.3% and common equity ratio of 53% compared to my recommended overall cost of capital. My analysis uses the Company's requested rate base and the tax rates, the NCUC fee percentage, and the uncollectible rate from the Company's Exhibit C. *Duke Carolinas' requested return on rate base would cost North Carolina ratepayers an additional $157.1 million per year in their rates compared to my recommendation.*

In conclusion, a 9.00% ROE and an actual 51.5% common equity ratio is more than adequate to meet *Hope* and *Bluefield* standards with respect to comparable returns, financial integrity and ability to attract capital. It will also satisfy the requirement for the Commission's consideration of the economic impact on North Carolina ratepayers from the allowed rate of return in this case.

V. <u>RESPONSE TO DUKE CAROLINAS' DIRECT TESTIMONY</u>

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF MR. ROBERT HEVERT?

A. Yes.

Q. PLEASE SUMMARIZE MR. HEVERT'S TESTIMONY AND APPROACH TO RETURN ON EQUITY.

A. Mr. Hevert employed three methods to estimate the investor required rate of return for Duke Carolinas: (1) the constant growth DCF model, (2) the CAPM and the empirical CAPM ("ECAPM"), and (3) the Bond Yield Plus Risk Premium model ("BYRP"). Mr. Hevert also presented the results of the Expected Return approach based on Value Line's forecasted returns on book equity for the proxy group.

For his constant growth DCF approach, Mr. Hevert used Value Line, First Call, and Zacks for the investor expected growth rate. For the proxy group, Mr. Hevert's mean growth rate ROE results ranged from 8.86% to 9.09%.[18]

With respect to the CAPM, Mr. Hevert utilized a current and near-term projected yield on the 30-Year Treasury Bond for his risk-free rate. Using the current Treasury bond yield of 2.63%, his CAPM results ranged from 8.68% to 9.74%. Using the near-term projected Treasury yield of 2.70%, his CAPM results ranged from 8.75% to 9.81%.[19]

Mr. Hevert's ECAPM variation of the CAPM yielded results ranging from 10.21% to 11.10%.[20]

Finally, Mr. Hevert's formulation of the BYRP approach resulted in a ROE range of 9.90% - 10.06%.[21]

[18] Refer to Mr. Hevert's Direct Testimony, page 80, Table 6.

[19] *Id.*, page 87, Table 7.

[20] *Id.*, page 92, Table 8.

[21] *Id.*, page 96, Table 9.

Based on the results of his analyses and judgment, Mr. Hevert recommended a ROE range for Duke Carolinas of 10.00% to 11.00%, concluding that the cost of equity is 10.50%.[22]

Q. BEFORE YOU PROCEED TO THE PARTICULARS OF YOUR REVIEW OF MR. HEVERT'S TESTIMONY, WHAT IS YOUR OVERALL CONCLUSION WITH RESPECT TO MR. HEVERT'S RECOMMENDED ROE RANGE?

A. Mr. Hevert's recommended ROE range of 10.00% – 11.00% fails to reflect the full range of results from his analyses. His mean DCF results, which are fairly consistent with mine, were completely excluded from his range of recommendations. Based on the ROE results presented by Mr. Hevert, it appears that he mainly relied on the upper range of his CAPM and ECAPM and his BYRP method for the lower end of his recommended range.

To put this another way, consider the following:

- Mr. Hevert rejected the mean results from the constant growth DCF in total.
- Mr. Hevert also apparently rejected his CAPM results given that the top end of his CAPM range was 9.81%.

What we are left with, then, is the BYRP results of 9.90% - 10.06% being consistent with Mr. Hevert's floor recommendation of 10.0%. His ECAPM results also fall within his recommended range. Although Mr. Hevert presented

[22] *Id.*, page 13.

three different approaches to estimating the cost of equity for Duke Carolinas, he rejected the DCF model and CAPM results and relied almost exclusively on the ECAPM and BYRP.

Q. IS IT APPROPRIATE FOR MR. HEVERT TO REJECT THE MEAN RESULTS FROM HIS DCF ANALYSES?

A. No. It is inappropriate for Mr. Hevert to exclude the mean results of the constant growth DCF model in his recommended ROE for Duke Carolinas. The constant growth DCF model utilizes verifiable public information with respect to investor return requirements for electric utilities. Current stock prices are the best indicators we have of investor expectations and analysts' earnings and dividend growth forecasts may reasonably be assumed to influence investors' required ROEs. Discarding this important publicly available information as Mr. Hevert has done serves to significantly overstate his recommended investor required return for a low-risk regulated utility company such as Duke Carolinas. The DCF model currently shows that investor required returns are considerably lower for utility stocks given their safety and security relative to the stock market as a whole.

Q. IS USING THE HIGH MEAN RESULTS FROM THE DCF MODELS APPROPRIATE?

A. No. Mr. Hevert's high mean results simply use the highest ROE for each company in the proxy group, which is driven by the highest expected growth rate. There is no basis for assuming that investors are more likely to expect the highest growth rate from the three sources used by Mr. Hevert. The average of the three sources is a far more likely and reasonable assumption. For example, the proxy group high mean using Mr. Hevert's 180-day average stock price is unduly influenced by excessive ROE estimates for Avangrid (13.71%), NextEra Energy (12.83%), Otter Tail (11.97%), and PNM Resources (11.23%).[23]

Q. ON PAGE 80, LINES 9 THROUGH 16 OF HIS DIRECT TESTIMONY, MR. HEVERT CRITICIZED THE USE OF THE DCF MODEL ON CERTAIN GROUNDS. PLEASE ADDRESS MR. HEVERT'S CRITICISMS.

A. Mr. Hevert testified that the DCF model is predicated on a number of assumptions, one being a constant price/earnings (P/E) ratio. Since P/E ratios in the utility sector are currently above their long-term average and the market's P/E, Mr. Hevert recommended caution when viewing the DCF results. Mr. Hevert also testified that the DCF model is producing results below the authorized returns for electric utilities.

First, before I proceed to a more detailed response to Mr. Hevert's criticisms of the DCF model's assumptions, it is important to realize that none of the models Mr. Hevert and I use to estimate the investor required ROE strictly adhere to their underlying assumptions 100% of the time in the real world. The DCF, CAPM, and risk premium models all operate with certain simplifying assumptions. In Section III of my testimony I pointed out the limitations of the CAPM that must be considered in assessing its effectiveness

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[23] *See* Exhibit RBH-1, page 3 of 3.

relative to the DCF model. One of those limitations is estimating the market required rate of return. Estimating the market required rate of return requires considerable judgment on the part of the analyst, judgment that may result in a wide range of possible returns. In this case, Mr. Hevert and I used very different estimates of the market rate of return that caused our CAPM results to differ considerably. I will address the serious underlying problems with Mr. Hevert's CAPM later in my testimony.

I suggest that the Commission recognize that no ROE estimation model strictly adheres to its underlying assumptions all the time.

Q. PLEASE CONTINUE WITH YOUR RESPONSE TO MR. HEVERT'S CRITICISM OF THE DCF MODEL'S ASSUMPTIONS.

A. With respect to the assumption of a constant P/E ratio, simply because the utility industry's current P/E ratio may be above the long-term average P/E ratio does not mean that the DCF results based on current data are questionable and should be thrown out. As I have stated previously in my testimony, capital markets are efficient and can be assumed to reflect investor preferences in the prices they are willing and able to pay for a regulated utility's common stock. This includes publicly available information to which investors have access, including P/E ratios. What this means is that it is reasonable to assume that current stock prices are reflective of investors' required ROE and that the DCF model can provide valid and valuable information to the Commission in its determination of the allowed ROE for regulated utilities generally and for Duke Energy Carolinas in this case.

Q. ON PAGE 81, LINES 10 THROUGH 19 OF HIS DIRECT TESTIMONY, MR. HEVERT TESTIFIED THAT THE DCF MODEL ASSUMES THAT THE RETURN TODAY WILL BE THE SAME RETURN REQUIRED IN THE FUTURE, "EVEN THOUGH THE FEDERAL RESERVE ONLY RECENTLY HAS COMPLETED THE PRINCIPAL INITIATIVES OF ITS MONETARY POLICY NORMALIZATION AND IS CONTINUING TO ASSESS REALIZED AND EXPECTED ECONOMIC CONDITIONS AS IT DETERMINES FUTURE ADJUSTMENTS, INTRODUCING A DEGREE OF UNCERTAINTY REGARDING FUTURE MONETARY POLICY ACTIONS." PLEASE COMMENT ON THIS STATEMENT.

A. Again, it is highly likely that investors have fully taken this information into account into the prices they are willing to pay for bonds and utility stocks. The Fed lowered the federal funds rate several times in 2019 and long-term Treasury yields have fallen significantly. During 2019, the 30-year Treasury bond yield fell from 3.04% in January to 2.3% December. Clearly, the trend in the economy over the last year shows that capital costs are declining, not increasing, and one would expect that investor required ROEs for low-risk regulated electric utilities like Duke Carolinas would follow that trend.

Furthermore, all of the models used to estimate the investor's required ROE must fix a return "today" since no one knows with certainty what will happen in the future, including what investor expected returns will be. Future events and economic conditions will affect the required ROE in ways we cannot predict now.

Q. ON PAGE 82 OF HIS DIRECT TESTIMONY, MR. HEVERT TESTIFIED THAT SINCE 1980 ONLY ELEVEN UTILITY RATE CASES INCLUDED AN AUTHORIZED ROE OF LESS THAN 9.0%. PLEASE RESPOND TO MR. HEVERT'S TESTIMONY ON THIS POINT.

A. Including rate cases since 1980 is an irrelevant exercise because it places too much emphasis on stale data. In the 1980s and 1990s interest rates and allowed ROEs were far higher than they have been in the last few years. Consider the following information I developed using the data in Mr. Hevert's Exhibit RBH-5:

- From 1980 through 1989, the average awarded ROE was 14.80% and the average 30-Year Treasury Bond yield was 11.35%.
- From 1990 through 1999, the average awarded ROE was 11.91% and the average 30-Year Treasury Bond yield was 7.51%.
- From 2000 through 2009, the average awarded ROE was 10.62% and the average 30-Year Treasury Bond yield was 4.81%.

These averages give the Commission a general picture of the interest rate and ROE levels from the 1980s, 1990s, and 2000s and represent 1,218 of the 1,594 observations in Mr. Hevert's data set in Exhibit RBH-5. They are in no way indicative of investor required returns today given how much higher interest rates were during these prior periods.

Further consider that Mr. Hevert's recommendation of 10.5% is close to the average ROE from 2000 – 2009 of 10.62%. During that period the average 30-year Treasury Bond yield was 4.81%, which is almost 250 basis points higher than the December 2019 yield of 2.3%. With Treasury Bond yields so much lower now, Mr. Hevert's ROE recommendation of 10.5% is clearly out of line.

Q. ON PAGE 80, LINES 14 THROUGH 16 OF HIS DIRECT TESTMONY MR. HEVERT TESTIFIED THAT THE MEAN CONSTANT GROWTH DCF RESULTS ARE BELOW THE AUTHORIZED RETURN FOR ELECTRIC UTILITIES. HOW DO MR. HEVERT'S ECAPM RESULTS COMPARE WITH RECENT AUTHORIZED RETURNS?

A. Mr. Hevert's ECAPM ROEs based on the average Value Line beta range from 10.96% to 11.10% and are consistent with the upper end of Mr. Hevert's recommended ROE range. These results are grossly in excess of current market-based returns as well as ROEs allowed in the last several years. Based on the authorized ROE data in Exhibit RBH-5, one would have to go back to 2011 to find an authorized ROE near or above 11.0%. Although Mr. Hevert criticized the DCF model results for being below authorized returns, he did not apply the same criterion to test whether his ECAPM results were reasonable.

Q. CONSIDERING THE FOREGOING DISCUSSION, PLEASE SUMMARIZE YOUR CONCLUSIONS WITH RESPECT TO MR. HEVERT'S RECOMMENDED ROE RANGE AND HIS ROE RECOMMENDATION FOR DUKE CAROLINAS.

A. I conclude that the Commission should reject Mr. Hevert's recommended ROE range and his recommended ROE of 10.50%. Mr. Hevert's 10.50% ROE recommendation is excessive in today's market environment. Mr. Hevert's ROE range omits critically important information from the DCF model and, as a result, misstates the investor required ROE for a low-risk utility such as Duke Carolinas.

CAPM and ECAPM

Q. BRIEFLY SUMMARIZE THE MAIN ELEMENTS OF MR. HEVERT'S CAPM APPROACH.

A. On pages 84 and 85 of his Direct Testimony, Mr. Hevert testified that he used two different measures of the risk-free rate: the current 30-day average yield on the 30-year Treasury bond (2.63%) and a near-term projected 30-year Treasury bond yield (2.70%). Mr. Hevert then calculated ex-ante measures of total market returns for the S&P 500 using data from Bloomberg and Value Line. Total market returns from these two sources were 14.46% using Bloomberg data and 14.62% return using Value Line data.[24] Subtracting out the risk-free rate, the resulting market risk premiums were 12.04% – 12.19%.

Mr. Hevert used two different estimates for beta from Bloomberg (0.498) and Value Line (0.58).[25]

Q. IS IT APPROPRIATE TO USE FORECASTED OR PROJECTED BOND YIELDS IN THE CAPM?

A. No. Current interest rates and bond yields embody all of the relevant market data and expectations of investors, including expectations of changing future interest rates. The forecasted bond yield used by Mr. Hevert is at odds with the trend of declining long-term bond yields in 2019. Current interest rates provide

[24] Refer to Exhibit RBH-2.

[25] Refer to Exhibit RBH-3.

tangible and verifiable market evidence of investor return requirements today and these are the interest rates and bond yields that should be used in both the CAPM and in the bond yield plus risk premium analyses. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

In this case, however, Mr. Hevert's forecasted bond yield is not significantly different from his current bond yield. I would also note that current 30-year Treasury yields have declined since Mr. Hevert submitted his Direct Testimony, with a January 2020 yield of 2.22%. In comparison, my range for the risk-free rate is 2.21% – 3.00%, with a midpoint of 2.6%, so our estimates for the risk-free rate do not differ significantly in this proceeding.

Q. HOW DO MR. HEVERT'S ESTIMATES OF THE OVERALL MARKET RETURN COMPARE TO YOURS?

A. My estimates of the market required return are as follows:

- Value Line 3-5 Year Total Return: 11.0% – 12.21%
- Value Line Growth Rates: 10.61%
- S&P Average Historical Returns: 11.90%

Mr. Hevert's forecasted market returns of 14.48% – 14.62% are extraordinarily high compared to historical norms. Further, his calculation of the market return using Value Line's 3 – 5 year earnings growth estimates greatly exceeds the Value Line 3 – 5 year total annual return numbers I used from the Value Line Investment Analyzer. Moreover, the number of companies the Value Line Investment Analyzer used to develop the total annual return numbers I used was 1,682, a far greater number of companies than the S&P 500 used by Mr. Hevert. I recommend that the Commission give Mr. Hevert's estimated market returns little weight in this proceeding.

Q. ARE THERE SOURCES OF WHICH YOU ARE AWARE THAT SUGGEST MR. HEVERT'S MARKET RISK PREMIUM RANGE OF 12.04% - 12.19% IS UNREASONABLY HIGH?

A. Yes. In the authoritative corporate finance textbook by Brealey, Myers, and Allen the authors stated:

> "Brealey, Myers, and Allen have no official position on the issue, but we believe that a range of 5 to 8 percent is reasonable for the risk premium in the United States."[26]

As I cited earlier in my Direct Testimony, Duff and Phelps currently recommends a market risk premium of 5.5% and an overall U. S. cost of equity of 8.5%. These sources underscore how much Mr. Hevert's recommended market risk premiums inflated his CAPM and ECAPM ROE estimates.

Q. BEGINNING ON PAGE 88 OF HIS DIRECT TESTIMONY, MR. HEVERT EXPLAINED THAT HE ALSO INCLUDED THE ECAPM ANALYSIS. PLEASE COMMENT ON MR. HEVERT'S USE OF THE ECAPM IN THIS CASE.

A. The ECAPM is designed to account for the possibility that the CAPM understates the return on equity for companies with betas less than 1.0. Mr. Hevert explained on page 88 of his Direct Testimony how he applied the adjustment to his CAPM data, which was based on the formula included in *New Regulatory Finance* by Dr. Roger Morin.

[26] Richard A. Brealey, Stewart C. Myers, and Paul Allen, *Principles of Corporate Finance*, page 154; McGraw-Hill/Irwin, 8th Edition, 2006.

The argument that an adjustment factor is needed to "correct" the CAPM results for companies with betas less than 1.0 is further evidence of the lack of accuracy inherent in the CAPM itself and with beta in particular, as I pointed out earlier in my Direct Testimony. The ECAPM adjustment also suggests that published betas by such sources as Value Line and Bloomberg are incorrect and that investors should not rely on them in formulating their estimates using the CAPM. Finally, although Mr. Hevert cited the source of the ECAPM formula he used, he provided no evidence that investors favor this version of the ECAPM over the standard CAPM.

Q. PLEASE COMMENT ON THE ECAPM RESULTS REPORTED BY MR HEVERT ON HIS TABLE 8 ON PAGE 92 OF HIS DIRECT TESTIMONY.

A. The ECAPM results using the Average Value Line beta Coefficient —10.96% to 11.10%—are excessive and implausible. To provide the Commission with some perspective here, according to the data presented by Mr. Hevert in his Exhibit RBH-5, the last Commission authorized ROE exceeding 11.00% was September 2, 2011 (12.88%) and that value far exceeded the other Commission allowed ROEs in 2011. I would also point out that the average 30-Year Treasury Bond yield in 2011 was 4.13%, a far higher yield than the recent 2.30% yield for the 30-Year Treasury Bond. Mr. Hevert's ECAPM results using the Value Line beta are so disproportionately high that they should be rejected out of hand by the Commission.

<u>Risk Premium</u>

Q. PLEASE SUMMARIZE MR. HEVERT'S RISK PREMIUM APPROACH.

A. Mr. Hevert developed an historical risk premium using Commission-allowed returns for regulated electric utility companies and 30-year Treasury Bond yields from January 1980 through May 23, 2019. He used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. Applying the regression coefficients to the average risk premium and using the current and projected 30-year Treasury yields I discussed earlier and also employing a long-term projected 30-year Treasury Bond yield of 3.70%, Mr. Hevert's risk premium ROE estimate range is 9.90% – 10.06%.[27]

Q. PLEASE RESPOND TO MR. HEVERT'S RISK PREMIUM ANALYSIS.

A. There are two major flaws in Mr. Hevert's analysis. First, it measures the returns allowed by regulatory commissions, not investor required returns reflected in marketplace data; and second, it relies on historical allowed returns dating back to 1980 rather than recent returns. The bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility. Risk premiums can change substantially over time based on investor preferences and market conditions. These changes will not be incorporated into an historical risk premium analysis of the type Mr. Hevert uses that employs historical commission allowed ROEs. As such, this approach is a "blunt instrument," if

[27] Hevert Direct Testimony, page 96, Table 9.

you will, for estimating the ROE in regulated proceedings. In my view, a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate than the bond yield plus risk premium approach, which relies on a historical risk premium analysis based on the allowed returns over a certain period of time.

Q. DO MR. HEVERT'S RISK PREMIUM RESULTS ACCURATELY TRACK RECENTLY ALLOWED ROES?

A. No. Even assuming the Commission accepts the use of data about allowed ROEs as a substitute for market data, Mr. Hevert's model does not accurately track *recently* allowed ROE data. To test the accuracy of Mr. Hevert's BYRP model, I averaged the allowed returns and Treasury bond yields for 2018 as reported in Mr. Hevert's Exhibit RBH-5. The average allowed ROE for 2018 was 9.56% and the average 30-Year Treasury Bond yield was 2.99%. I then plugged in the 2.99% Treasury Bond yield to Mr. Hevert's BYRP formula in Exhibit RBH-5 and the resulting BYRP ROE was 9.92%. Compared to the actual average Commission-allowed 2018 ROE 9.56%, Mr. Hevert's formula overshot the actual ROE by 36 basis points, or 0.36%. Likewise using the December 2018 Treasury Bond yield of 2.30% in Mr. Hevert's BYRP formula results in a ROE of 9.93%, which is nearly identical to the 9.92% ROE result using a 2.99% Treasury Bond yield. It is clear that if the Treasury Bond yield falls, the expected ROE should also fall, but Mr. Hevert's BYRP formula result does not follow logically.

In my opinion, these calculations provide evidence to the Commission that using Mr. Hevert's risk premium model in today's economic environment will overstate the investor required ROE for a low-risk utility such as Duke Carolinas.

Expected Earnings

Q. BEGINNING ON PAGE 96 OF HIS DIRECT TESTIMONY, MR. HEVERT PRESENTED HIS EXPECTED EARNINGS ANALYSIS. PLEASE RESPOND TO MR. HEVERT'S ANALYSIS.

A. Mr. Hevert relied on Value Line's projected returns on book value equity for the period 2022-2024 for his expected earnings ROE estimate for the proxy group, which ranges from 10.44% – 10.54%.[28] He used the expected earnings analysis as a check on his other results.

The major flaw in the expected earnings approach is that it measures accounting returns on book value, not investor required returns in the marketplace. A market-based ROE estimation method like the DCF model uses stock market data and earnings growth forecasts to determine a forward-looking ROE estimate that incorporates true opportunity cost measured against the returns available to the investor in alternative investments such as other stocks, bonds, real estate, and so forth. Further, changes in economic variables such as interest rates will affect the required returns of utility stock investments and other investments as well. Such changes will be incorporated into the DCF and

[28] Mr. Hevert Direct Testimony, page 97.

CAPM models, which use current market data. These changes will not be reflected in book returns on common equity.

Turning to Mr. Hevert's expected earnings approach, he provided absolutely no support for the assumption that Value Line's projected accounting returns on book value in the 2022 – 2024 projected time period have any influence whatsoever on required returns in today's financial marketplace or that they provide a useful benchmark in estimating current required returns. I recommend the Commission reject Mr. Hevert's expected earnings approach and instead use market-based ROE estimation models to set Duke Carolinas' allowed ROE in this proceeding.

Use of Multiple Methods to Estimate the Cost of Equity

Q. DID THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC") RECENTLY ISSUE AN ORDER REGARDING USING MULTIPLE MODELS IN ESTIMATING THE ROE?

A. Yes. FERC recently issued its Opinion No. 569 on November 21, 2019, Docket Nos. EL14-12-003 and EL15-45-000 regarding the methods used to estimate a just and reasonable ROE under the Federal Power Act ("FPA") section 206. In this Opinion, the FERC rejected using the Risk Premium and Expected Earnings approaches to estimating the ROE. FERC stated:

> 1. On November 15, 2018, the Commission issued an Order Directing Briefs in the above-captioned proceedings. The Briefing Order directed the participants in the above captioned proceedings to submit briefs regarding: (1) a proposed framework for determining whether an existing base return on equity (ROE) is unjust and unreasonable under the first prong of Federal Power Act (FPA) section 206; and (2) a revised methodology for determining just and reasonable base ROEs

> under the second prong of FPA section 206. As discussed below, we will adopt the proposal in the Briefing Order, with certain revisions. *Principally, we will not adopt the use of the expected earnings (Expected Earnings) and risk premium (Risk Premium) models in our ROE analyses under the first and second prongs of section 206, and instead will use only the discounted cash flow (DCF) model and capital-asset pricing model (CAPM) in our ROE analyses under both prongs of section 206.* (emphasis added)

Flotation Costs

Q. BEGINNING ON PAGE 34 OF HIS DIRECT TESTIMONY, MR. HEVERT PRESENTED HIS POSITION REGARDING THE NEED TO RECOGNIZE THE EFFECT OF FLOTATION COSTS IN THE COST OF EQUITY. PLEASE ADDRESS MR. HEVERT'S POSITION ON FLOTATION COSTS.

A. A flotation cost adjustment attempts to recognize and collect the costs of issuing common stock. Such costs typically include legal, accounting, and printing costs as well as broker fees and discounts. In my opinion, it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. This is not an appropriate assumption regarding investor expectations. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

Business Risks and Other Considerations

Q. BEGINNING ON PAGE 37 OF HIS DIRECT TESTIMONY, MR. HEVERT PROCEEDED TO DESCRIBE SEVERAL BUSINESS RISKS AND OTHER FACTORS THAT HE RECOMMENDED BE TAKEN INTO CONSIDERATION "WHEN DETERMINING WHERE DUKE CAROLINAS' COST OF EQUITY FALLS WITHIN THE RANGE OF RESULTS." PLEASE RESPOND TO MR. HEVERT'S DISCUSSION OF THESE FACTORS AND WHETHER THEY SHOULD INFLUENCE THE COMMISSION'S DECISION REGARDING DUKE CAROLINAS' RETURN ON EQUITY.

A. I found Mr. Hevert's discussion regarding the "additional factors" to be considered by the Commission a one-sided view of the overall riskiness of Duke Carolinas. Instead, I recommend that the Commission instead consider my discussion of the Company's credit strengths and challenges in Section II of my testimony as enumerated by Moody's. The credit challenges enumerated by Moody's were supplemented by consideration of the Company's credit strengths, which support an A1 credit rating. This credit rating is above average when compared to the EEI's average S&P credit rating for the electric utilities it follows of BBB+. Duke Carolinas' A1 credit rating is at the top of the A rating category for Moody's and, if anything, suggests that the Commission should grant an ROE below the mean results. Overall, I suggest that the Commission look to Duke Carolinas' strong overall credit ratings as the indicator of the Company's riskiness compared to the proxy group. These credit ratings do not support an above average return on equity for the Company.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-7, SUB 1214

DOCKET NO. E-2, SUB 1219	)	
	)	SUPPLEMENTAL
In the Matter of	)	DIRECT TESTIMONY OF
	)	
Application of Duke Energy Progress, LLC	)	RICHARD A. BAUDINO
For Adjustment of Rates and Charges Applicable	)	ON BEHALF OF
to Electric Service in North Carolina	)	ATTORNEY GENERAL'S
	)	OFFICE
DOCKET NO. E-7, SUB 1214	)	
	)	
In the Matter of	)	
	)	
Application of Duke Energy Carolinas, LLC,	)	
For Adjustment of Rates and Charges	)	
Applicable to Electric Service in North Carolina	)	

I. QUALIFICATIONS AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a consultant with Kennedy and Associates.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THESE DOCKETS?

A. Yes, I filed Direct Testimony in these dockets on behalf of the North Carolina Attorney General's Office ("AGO").

Q. PLEASE SUMMARIZE YOUR SUPPLEMENTAL DIRECT TESTIMONY IN THIS PROCEEDING.

A. My Supplemental Direct Testimony will cover the following areas:

1. I will provide an update of the return on equity ("ROE") analyses for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP")[1] that were contained in my Direct Testimonies in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214.
2. I will provide an updated analysis of economic conditions in North Carolina.

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[1] I will refer to both DEC and DEP as "the Companies" later in my Supplemental Direct Testimony.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Based on my updated ROE analyses, I continue to recommend a 9.0% ROE for DEC and DEP. Consistent with my Direct Testimonies, I continue to recommend that the Commission adopt a capital structure for both Companies that contains a 51.5% common equity ratio. In addition, in light of the shocks that have been delivered to the national and the North Carolina economies and the attendant skyrocketing unemployment of North Carolina's work force due to the COVID-19 pandemic, it is more important than ever that the North Carolina Utilities Commission ("NCUC" or "Commission") reject the Companies' requested 10.30% ROE. My 9.0% ROE recommendation is consistent with current investor required returns for low-risk regulated electric companies like DEC and DEP and supports just and reasonable rates for the Companies' North Carolina customers.

II. UPDATE OF THE DCF AND CAPM ANALYSES

Q. PLEASE SUMMARIZE THE IMPACTS ON THE FINANCIAL MARKETS DURING MARCH THROUGH JUNE OF THIS YEAR FROM THE COVID-19 PANDEMIC.

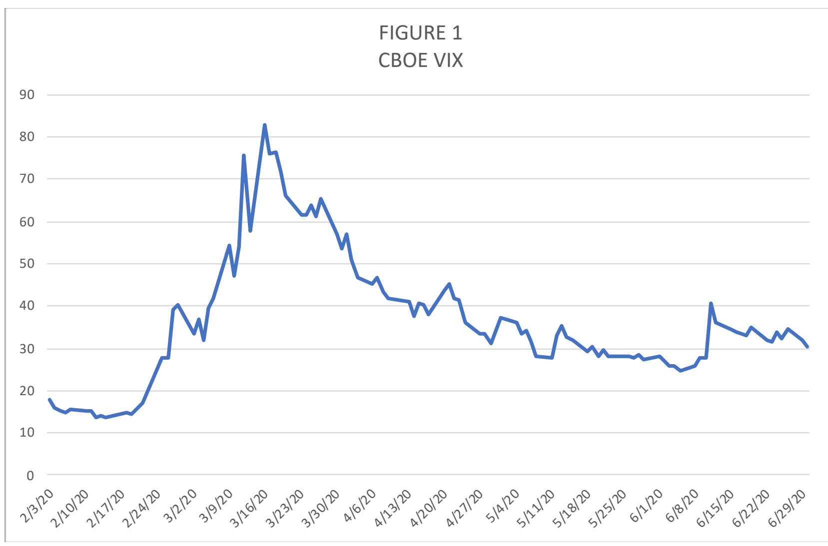
A. This section of my Supplemental Direct Testimony provides the Commission with an update of the interest rate and bond yield data since the beginning of March 2020, when concerns about the Covid-19 pandemic began to roil financial markets with extreme volatility.

As I mentioned in my Direct Testimony for DEP filed April 13, the yield on the 30-Year Treasury bond declined from 1.97% in February 2020 to 0.99% on March 9, increased to 1.63% on March 17, and ended March at 1.46%. The April ending yield on the 30-Year Treasury bond fell even further to 1.27%. As of June 30, 2020 the yield was 1.41%.

Alternatively, the yield on the average public utility bond increased dramatically in March, rising from 3.14% in February to 4.24% on March 18, according to Moody's Credit Trends. At the end of March, the average public utility bond yield fell to 3.59% according to the Mergent Bond Record. As of June 30, 2020 Moody’s Credit Trends reported that the yield on the average public utility bond was 3.05%, even lower than the March 2020 yield. The 3.05% yield is now significantly lower than the pre-pandemic January 2020 average utility bond yield of 3.34%.

In March, the stock market underwent a steep, sharp decline of approximately 19% due to the COVID-19 pandemic. Utilities also declined in March, with the Dow Jones utility average declining from 886.52 on March 2 to a March low of 695, a decline of about 21.6% with substantial volatility, or changes to the index's value, within the month. In April, however, the stock market and the Dow Jones utility index began to recover. After falling to a low in March of 695, the Dow Jones utility index recovered to finish April at 761.83, an increase of 9.6% from the March low. As of June 30, 2020, the Dow Jones Utility Index stood at 767.50, not much different from the end of April.

A widely used measure of market volatility is the Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX"), also called the "fear index" or "fear gauge." Basically, the VIX measures the market's expectations for volatility over the next 30-day period. The higher the VIX, the greater the expectation of volatility and market risk. Figure 1 below presents the VIX from February 1 through June 30, 2020. Figure 1 shows that the VIX was much lower in February, shot up to a high of 82.69 on March 16, then generally declined through June, with the VIX at 30.43 on June 30, 2020.



Q. PLEASE SUMMARIZE RECENT FED ACTIONS WITH RESPECT TO MONETARY POLICY.

A. As I testified in my Direct Testimony filed April 13 in the DEP proceeding, on March 3 and 15, 2020, the Fed lowered the federal funds rate in response to mounting concerns associated with the spread of the coronavirus worldwide. On June 10, 2020, the Fed issued a press release that stated the following:

> The Federal Reserve is committed to using its full range of tools to support the U.S. economy in this challenging time, thereby promoting its maximum employment and price stability goals.
>
> The coronavirus outbreak is causing tremendous human and economic hardship across the United States and around the world. The virus and the measures taken to protect public health have induced sharp declines in economic activity and a surge in job losses. Weaker demand and significantly lower oil prices are holding down consumer price inflation. Financial conditions have improved, in part reflecting policy measures to support the economy and the flow of credit to U.S. households and businesses. The ongoing public health crisis will weigh heavily on economic activity, employment, and inflation in the near term, and poses considerable risks to the economic outlook over the medium term. In light of these developments, the Committee decided to maintain the target range for the federal funds rate at 0 to 1/4 percent. The Committee expects to maintain this target range until it is confident that the economy has weathered recent events and is on track to achieve its maximum employment and price stability goals.
>
> The Committee will continue to monitor the implications of incoming information for the economic outlook, including information related to public health, as well as global developments and muted inflation pressures, and will use its tools and act as appropriate to support the economy.

Beginning in March 2020, the Federal Reserve also announced expanded actions to support credit and financial markets. The Board of Governors of the Federal Reserve System established a new resource on its web site that contains the Fed's ongoing response to the Covid-19 pandemic: https://www.federalreserve.gov/covid-19.htm. Some of the major actions undertaken by the Fed include the following:

- Creation of the Municipal Liquidity Facility to assist state and local governments manage cash flow to better serve households and businesses (April 9, 2020).

- Creation of the Main Street Lending Program to support small and medium sized businesses. There are three facilities that comprise this program: the Main Street New Loan Facility, the Main Street Priority Loan Facility, and the Main Street Expanded Loan Facility.
- Design of the Commercial Paper Funding Facility to support the flow of credit to households and businesses (March 17, 2020).
- Establishment of the Primary Dealer Credit Facility designed to support households and businesses (March 17, 2020).
- Establishment of the Money Market Mutual Fund Liquidity Facility as another program to facilitate the flow of credit to households and businesses (March 18, 2020).
- Establishment of the Primary and Secondary Corporate Credit Facilities that support credit to employers (March 23, 2020).
- Implementation of the Paycheck Protection Program Liquidity Facility to support the Small Business Administration's Paycheck Protection Program (April 9, 2020).
- Establishment of the Term Asset-Backed Securities Loan Facility ("TALF"), again to support the flow of credit to consumers and businesses (March 23, 2020).[2]

[2] For more information on the Fed's response to Covid-19, please see https://www.federalreserve.gov/funding-credit-liquidity-and-loan-facilities.htm

Q. PLEASE UPDATE THE COMMENTS FROM VALUE LINE'S REPORTS ON THE ELECTRIC UTILITY INDUSTRY THAT WERE PUBLISHED SINCE YOUR DIRECT TESTIMONY WAS FILED.

A. In its June 12, 2020 report on the Electric Utility (Central) Industry, Value Line noted the following:

> Electric utility stocks, as a group, have outperformed the broader market averages in 2020. There has been a wider-than-usual disparity in the performances of individual stocks. Electric company equities have exhibited more volatility than usual, too.

The Value Line report also noted that perhaps the "economic problems will result in a lower rate of dividend growth, but we do not expect the boards of any companies reviewed here to cut the disbursement."

Value Line also noted the following in its May 15, 2020 report on the Electric Utility (East) Industry:

> Utility stocks are seen as a safe (more accurately, less-risky) haven when the markets are turbulent. Most of the equities in this group have declined far less than the broader market averages since the market plummeted in late February. However, the volatility these issues have exhibited has belied their high Price Stability Indexes. The quotations of most stocks in the Electric Utility Industry have fallen between 10% and 20% so far this year. The average dividend yield for this group is 3.8%.

My conclusion from this discussion is that regulated electric utilities like DEC and DEP continue to be safe, conservative, and relatively stable investments even in the currently volatile financial market.

Q. WHAT ARE THE CURRENT CREDIT RATINGS FOR DUKE ENERGY PROGRESS AND DUKE ENERGY CAROLINAS?

A. The credit ratings for DEC and DEP have not changed since I filed my Direct Testimony. DEC has an A1 rating from Moody's and an A- rating from Standard and Poor's ("S&P"). DEP has an A2 credit rating from Moody's and an A- rating from S&P. These ratings all have stable outlooks.

Q. PLEASE PRESENT YOUR UPDATED ROE CALCULATIONS.

A. Supplemental Exhibits RAB-1 through RAB-4 present my updated ROE calculations. Supplemental Exhibit RAB-1 contains updated dividend yields for the companies in the Proxy Group that Companies witness Dylan D'Ascendis used in his Rebuttal Testimony. This is the same proxy group I used in my Direct Testimony, with the addition of Avista Corporation, a company that now meets Mr. D'Ascendis' criteria for inclusion. Stock prices were updated for the six-month period of January through June, 2020.

Supplemental Exhibit RAB-2 contains updated growth forecasts from the Value Line Investment Survey, Zacks, and Yahoo! Finance. This exhibit also contains updated ROE estimates using the Discounted Cash Flow ("DCF") method.

Supplemental Exhibits RAB-3 and RAB-4 present updated calculations for the Capital Asset Pricing Model ("CAPM"). Supplemental Direct Table 1 below provides a summary of the updated ROE results.

Supplemental Direct Table 1
SUMMARY OF ROE ESTIMATES

DCF Methodology	
Average Growth Rates	
- High	8.98%
- Low	8.29%
- Average	8.75%
Median Growth Rates:	
- High	9.28%
- Low	8.41%
- Average	8.88%
CAPM Methodology	
Forward-lookng Market Return:	
- Current 30-Year Treasury	9.25%
- D&P Normalized Risk-free Rate	9.61%
Historical Risk Premium:	
- Current 30-Year Treasury	6.19% - 6.98%
- D&P Normalized Risk-free Rate	7.56% - 8.35%

Q. PLEASE DISCUSS THE DIFFERENCES IN THE RESULTS FROM THE ANALYSES IN YOUR DIRECT TESTIMONY.

A. With respect to the DCF results, the updated six-month dividend yield increased to 3.32% from 2.88%. However, the average and median growth rates for Zacks, Yahoo! Finance, and Value Line declined. The resulting updated DCF ROEs increased slightly from those in my Direct Testimony, from 8.60% - 8.67% to 8.75% - 8.88%.

The CAPM results increased significantly due to a very large increase in the Value Line average beta value, from 0.56 in my Direct Testimony to 0.74 in the update. This represents an increase of 32.1% in the average beta for the proxy group. Indeed, my updated results for the forward-looking CAPM increased markedly to 9.25% - 9.61%. My updated results for the historical CAPM also increased significantly to 6.19% - 8.14%.

Q. BASED ON YOUR UPDATED ROE CALCULATIONS, WHAT IS YOUR ROE RECOMMENDATION IN THIS CASE?

A. I continue to recommend that the Commission adopt a 9.0% ROE for the Companies. Although the DCF results increased in the update, they did not increase enough to suggest a higher required ROE on the part of investors for low-risk regulated electric utility investments like DEC and DEP. Further, the stability of the Companies' current credit ratings do not suggest that the required ROE increased since I filed my Direct Testimonies. Likewise, although the CAPM results also increased, the range of both historical and forecasted ROE results continue to support 9.0% as just and reasonable.

Q. DOES THE TREND IN BOND YIELDS, BOTH FOR THE 30-YEAR TREASURY BOND AND AVERAGE UTILITY BONDS, SUGGEST AN INCREASE IN THE REQUIRED ROE FOR DEC AND DEP?

A. No. June 2020 yields were lower than they were in January 2020 for both the 30-Year Treasury Bond and for bonds of regulated utilities. This decline in bond yields does not support higher ROEs for the Companies.

Q. IS A SIX-MONTH PERIOD STILL APPROPRIATE FOR CALCULATING THE DIVIDEND YIELD FOR THE PROXY GROUP?

A. Yes. The updated six-month period of January through June 2020 is weighted more toward the more volatile period of the pandemic (March through June). Supplemental Exhibit RAB-1 shows that the monthly dividend yield for the proxy group increased significantly in March through May, then declined from May to June. March through June dividend yields are all much higher than

January and February. Given the volatility present in financial markets, I believe it is still advisable to include the more stable months of January and February in the average dividend yield calculation for the proxy group.

Q. YOU MENTIONED THAT THE CAPM RESULTS INCREASED SINCE YOU FILED YOUR DIRECT TESTIMONY AND THAT A LARGE INCREASE IN AVERAGE BETA FOR THE PROXY GROUP WAS RESPONSIBLE. PLEASE ADDRESS WHETHER THE COMMISSION SHOULD INCLUDE THE HIGHER CAPM RESULTS IN ITS CONSIDERATION OF THE ALLOWED ROE FOR DEC AND DEP IN THIS CASE.

A. I continue to recommend that the Commission rely on the DCF model for its ROE determination in this case. In my view, the sharp increase in betas for the companies in the proxy group was influenced by the extreme market volatility due to the Covid-19 pandemic. It is likely the increases in beta were due to greater volatility in the stock prices for regulated electric utilities relative to the movement of the market in general since the last Value Line reports that I relied on in my Direct Testimony. The question now is whether investors believe that regulated electric utilities are more risky relative to the general market than they were before the volatile period since March 2020. I believe the sharp increase in betas could be a short-term phenomenon and, as such, I would not advise placing much reliance on the CAPM results at this time. Certainly, the DCF results do not suggest a sharp increase in investor required ROEs for regulated electric companies.

The increase in the average beta factor for the proxy group underscores the shortcomings of the CAPM that I described in detail in my Direct Testimony in the DEP case. I point to pages 29 - 30 of my Direct Testimony where the problems with beta were set forth. The recent increase in the average beta for the proxy group is not consistent with the decline in average utility bond yields from January to June 2020. Also, given the decline in the Volatility Index (the "VIX" that I presented earlier), I believe it is highly unlikely that a 32% increase in expected betas for electric utilities since earlier in the year is accurate and reliable. In conclusion, the CAPM results should be viewed with even more caution and skepticism than when I filed my Direct Testimony in this proceeding.

Q. ARE YOU AWARE OF A RECENT ROE AWARD THAT WAS GRANTED TO DUKE ENERGY KENTUCKY BY THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes, I am aware of this Order, as I was involved in this case on behalf of the Attorney General of the Commonwealth of Kentucky. In its Order in Case No. 2019-00271 dated April 27, 2020 the Kentucky Public Service Commission ("KPSC") authorized an allowed ROE for Duke Energy Kentucky ("DEK") of 9.25%. The KPSC also authorized a common equity ratio of 48.23%. Further, the KPSC denied DEK's request for rehearing on the ROE issue in an Order dated June 4, 2020. In terms of credit ratings, DEK has a Moody's rating of Baa1 with a stable outlook and a S&P rating of A- with a stable outlook. These credit ratings are fairly similar to those of DEC and DEP. In fact, the Companies have slightly higher Moody's credit ratings (A2 and A1 for DEP and DEC, respectively). My recommendation of a 9.0% ROE with a 51.50% common equity ratio compares favorably with the KPSC Order for DEK.

I would like to add that I'm also aware that the KPSC made its ROE determination based on data that preceeded the Covid-19 pandemic and the associated market volatility that I described earlier in this testimony. However, my updated DCF analyses show the investor required return for regulated electric companies did not change significantly since I filed my Direct Testimony in the DEP case on April 13. I'm also aware that the NCUC will base its ROE decision in this case on the evidence presented to it and not on the ROE awards from other state commissions. Nevertheless, I wanted to provide this additional recent information from the KPSC Order for the Commission's consideration.

II. ECONOMIC CONDITIONS IN NORTH CAROLINA

Q. PLEASE SUMMARIZE THE CHANGES IN ECONOMIC CONDITIONS SINCE YOU FILED YOUR DIRECT TESTIMONY FOR DEC AND DEP.

A. The Covid-19 pandemic and the economic shutdowns that accompanied it, including that in North Carolina, caused an unprecedented economic contraction and skyrocketing unemployment. According to the U.S. Bureau of Labor Statistics, the unemployment rate for the United States rose from 3.5% in February 2020 to a high of 14.7% in April 2020. The unemployment rate for May 2020 was 13.3% and declined further in June 2020 to 11.1%. For North

Carolina, the unemployment rate rose from 3.6 in February 2020 to 12.9% in May the same as the rate for April.[3]

Nationally, real Gross Domestic Product ("GDP") declined in the first quarter of 2020 by -5.0%, according to the Bureau of Economic Analysis ("BEA").[4] The BEA also reported that profits from current production (corporate profits with inventory valuation and capital consumption adjustments) decreased $262.8 billion in the first quarter, in contrast to an increase of $53.0 billion in the fourth quarter of 2019.

Q. HOW DO THESE CHANGED ECONOMIC CONDITIONS AFFECT YOUR ROE RECOMMENDATION IN THESE PROCEEDINGS?

A. The ongoing Covid-19 pandemic continues to significantly affect economic activity, as well as the employment and incomes of North Carolinians. As I stated in my Direct Testimony on page 48, it is more important than ever for the Commission to consider the impacts of the Companies' requested ROE of 10.3% - 10.5% on North Carolina ratepayers. The Companies' ratepayers simply cannot afford to be saddled with an excessive ROE in this range. Based on current economic conditions and on my updated analyses, I continue to recommend that the Commission authorize the Companies a ROE of 9.0%.

3 The May 2020 unemployment rate for North Carolina is preliminary. Data from *North Carolina Labor Market Conditions, May 2020*, North Carolina Department of Commerce. The June 2020 North Carolina unemployment rate was not available at the time I prepared my Supplemental Direct Testimony.

4 https://www.bea.gov/news/2020/gross-domestic-product-1st-quarter-2020-third-estimate-corporate-profits-1st-quarter-2020.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes.

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-seven years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Director of Consulting, Consultant** - Responsible for consulting assignments in revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Aqua Large Users Group
Assn. of Business Advocating Tariff Equity
Atmos Cities Steering Committee
Canadian Federation of Independent Businesses
CF&I Steel, L.P.
Cities of Midland, McAllen, and Colorado City
Cities Served by Texas-New Mexico Power Co.
Cities Served by AEP Texas
City of New York
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
Crescent City Power Users Group
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
North Carolina Attorney General's Office
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
Philadelphia Large Users Group
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area
Vermont Department of Public Service
Texas Industrial Energy Consumers

Expert Testimony Appearances
of
Richard A. Baudino
As of February 2020

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of February 2020

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of February 2020

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Evaluation of cost allocation, rate design, rate plan, and carrying charge proposals.
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of February 2020**

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

Expert Testimony Appearances
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Richard A. Baudino
As of February 2020

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

Expert Testimony Appearances
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Richard A. Baudino
As of February 2020

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

Expert Testimony Appearances
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Richard A. Baudino
As of February 2020

Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

**Expert Testimony Appearances
of
Richard A. Baudino
As of February 2020**

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

Expert Testimony Appearances
of
Richard A. Baudino
As of February 2020

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-E-42T	WV	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues
08/16	8710	VT	Vermont Dept. of Public Service	Vermont Gas Systems	Return on equity, cost of debt, cost of capital
08/16	R-2016-2537359	PA	AK Steel Corp.	West Penn Power Co.	Cost and revenue allocation
09/16	2016-00162	KY	Kentucky Office of the Attorney General	Columbia Gas of Ky.	Return on equity, cost of short-term debt
09/16	16-0550-W-P	WV	West Va. Energy Users Gp.	West Va. American Water Co.	Infrastructure Replacement Program Surcharge
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring fencing and other conditions for acquisition, service quality and reliability
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP and Sharyland Dist. and Transmission Services, LLC	Return on equity
02/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
03/17	10580	TX	Atmos Cities Steering Committee	Atmos Pipeline Texas	Return on equity, capital structure, weighted cost of capital
03/17	R-3867-2013	Quebec, Canada	Canadian Federation of Independent Businesses	Gaz Metro	Marginal Cost of Service Study

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Date	Case	Jurisdict.	Party	Utility	Subject
05/17	R-2017-2586783	PA	Philadelphia Industrial and Commercial Gas Users Gp.	Philadelphia Gas Works	Cost and revenue allocation, rate design, Interruptible tariffs
08/17	R-2017-2595853	PA	AK Steel	Pennsylvania American Water Co.	Cost and revenue allocation, rate design
8/17	17-3112-INV	VT	Vt. Dept. of Pubic Service	Green Mountain Power	Return on equity, cost of debt, weighted cost of capital
9/17	4220-UR-123	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
10/17	2017-00179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity, cost of short-term debt
12/17	2017-00321	KY	Office of the Attorney General	Duke Energy Kentucky, Inc.	Return on equity
1/18	2017-00349	KY	Office of the Attorney General	Atmos Energy	Return on equity, cost of debt, weighted cost of capital
5/18	Fiscal Years 2019-2021 Rates	PA	Philadelphia Large Users Group	Philadelphia Water Department	Cost and revenue allocation
8/18	18-0974-TF	VT	Vt. Dept. of Public Service	Green Mountain Power	Return on equity, cost of debt, weighted cost of capital
8/18	48401	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Co.	Return on equity, capital structure
8/18	18-05-16	CT	Connecticut Industrial Energy Consumers	Connecticut Natural Gas Co.	Cost and revenue allocation
9/18	9484	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design
9/18	2017-370-E	SC	South Carolina Office of Regulatory Staff	South Carolina Electric & Gas, Dominion Resources, SCANA	Return on equity, service quality standards, credit quality conditions
10/18	18-1115-G-390P	WV	West Va. Energy Users Group	Mountaineer Gas Company	Customer protections for Infrastructure Replacement and Expansion Program
12/18	R-2018-3003558, R-2018-3003561	PA	Aqua Large Users Group	Aqua Pennsylvania, Inc.	Cost and revenue allocation
02/19	UD-18-07	CCNO	Crescent City Power Users' Gp.	Entergy New Orleans, LLC	Return on equity, Reliability Incentive Mechanism, other proposed riders
03/19	2018-00358	KY	Office of the Attorney General	Kentucky American Water Co.	Return on equity, Qualified Infrastructure Program rider
05/19	19-E-0065 19-G-0066	NY	City of New York	Consolidated Edison Co.	Cost and revenue allocation, rate design, tariff issues, fast-charging station incentives

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Date	Case	Jurisdict.	Party	Utility	Subject
05/2019	19-0513-TF	VT	Vt. Dept. of Public Service	Vermont Gas Systems	Return on equity, capital structure
06/2019	5-TG-100	WI	Wisconsin Industrial Energy Group	WEPCO, Wisconsin Gas, Wisconsin PS	Transportation and balancing issues
07/2019	49494	TX	Cities Served by AEP Texas	AEP Texas, Inc.	Return on equity, capital structure
08/2019	19-G-0309 19-G-0310	NY	City of New York	Brooklyn Union Gas Co.., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, tariff issues and modifications
08/2019	19-0316-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Company	Cost and revenue allocation
8/2019	5-UR-109	WI	Wisconsin Industrial Energy Gp.	Wisconsin Electric Power Co., Wisconsin Gas, LLC	Cost Allocation, Class cost of service study
8/2019	6690-UR-126	WI	Wisconsin Industrial Energy Gp.	Wisconsin Public Service Corp.	Cost Allocation, Class cost of service study
9/2019	9610	MD	Maryland Energy Group	Baltimore Gas and Electric Co.	Cost and revenue allocation, rate design
12/2019	2019-00271	KY	Office of the Attorney General	Duke Energy Kentucky, Inc.	Return on equity
2/2020	49831	TX	Texas Industrial Energy Consumers	Southwestern Public Service Co.	Return on equity, capital structure, rate of return
2/2020	E-7. Sub 1214	NC	NC Attorney General's Office	Duke Energy Carolinas	Return on equity, capital structure, rate of return, economic conditions

(Whereupon, the prefiled corrected testimony of Paul J. Alvarez was copied into the record as if given orally from the stand.)

(Alvarez Exhibits 1-15 were admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of: **Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina**	)))))))))))	**CORRECTED TESTIMONY OF PAUL J. ALVAREZ ON BEHALF OF THE NORTH CAROLINA JUSTICE CENTER, NORTH CAROLINA HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL, SOUTHERN ALLIANCE FOR CLEAN ENERGY AND THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION**

Wired Group

PO Box 620756

Littleton, Colorado 80162

February 25, 2020

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Alvarez Exhibit 1: Curriculum Vitae of Paul Alvarez

Alvarez Exhibit 2: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 5-3, Docket No. E-7, Sub 1214, January 27, 2020.

Alvarez Exhibit 3: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 8-24, Docket No. E-7, Sub 1214, February 11, 2020 & Duke Energy Progress Response to NCJC et al. 5-22, Docket No. E-2, Sub 1219.

Alvarez Exhibit 4: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 8-1, Docket No. E-7, Sub 1214, February 10, 2020 & Duke Energy Progress Response to North Carolina Justice Center, *et. al.*, Data Request 5-1, Docket No. E-2, Sub 1219, February 10, 2020.

Alvarez Exhibit 5: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 8-26, Docket E-7, Sub 1214, February 10, 2020 & Duke Energy Progress Response to North Carolina Justice Center, *et. al.*, Data Request 5-17, Docket No. E-2, Sub 1219, February 10, 2020.

Alvarez Exhibit 6: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 8-25, Docket E-7, Sub 1214, February 11, 2020 & Duke Energy Progress Response to North Carolina Justice Center, *et. al.*, Data Request 5-16, Docket No. E-2, Sub 1219, February 10, 2020.

Alvarez Exhibit 7: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 2-5, Docket No. E-7, Sub 1214, January 9, 2020.

Alvarez Exhibit 8: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 5-4, Docket No. E-7, Sub 1214, January 27, 2020.

Alvarez Exhibit 9: Duke Energy Carolinas Response to North Carolina Sustainable Energy Association, *et. al*,. Data Request 2-52 and 2-53, Docket No. E-7, Sub 1214, November 25, 2019.

Alvarez Exhibit 10: Paul Alvarez Analyses of Program-Specific Cost-Benefits.

Alvarez Exhibit 11: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 8-27, Docket No. E-7, Sub 1214, February 10, 2020 & Duke Energy Progress Response to North Carolina Justice Center *et. al.*, Data Request 5-18, Docket No. E-2, Sub 1219, February 10, 2020.

Alvarez Exhibit 12: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 8-28, Docket No. E-7, Sub 1214, February 10, 2020 & Duke Energy

Progress Response to North Carolina Justice Center *et. al*., Data Request 5-19, Docket No. E-2, Sub 1219, February 10, 2020.

Alvarez Exhibit 13: Duke Energy Carolinas Response to North Carolina Justice Center *et. al*,. Data Request 5-32; Docket E-7, Sub 1214, January 27, 2020 & Duke Energy Carolinas Response to North Carolina Sustainable Energy Association, *et. al*,. Data Request 3-11, Docket E-7, Sub 1214, January 2, 2020.

Alvarez Exhibit 14: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al*., Data Request 5-10, Docket No. E-7, Sub 1214, January 27, 2020 & Duke Energy Progress Response to North Carolina Justice Center *et. al*., Data Request 2-7, Docket No. E-2, Sub 1219, January 24, 2020.

Alvarez Exhibit 15: Duke Energy Carolinas Response to North Carolina Sustainable Energy Association, *et. al*,. Data Request 2-16, Docket No. E-7, Sub 1214, November 25, 2019.

I. Introduction

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My full name is Paul J. Alvarez. My business address is Wired Group, Post Office Box 620756, Littleton, Colorado, 80162.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the President of the Wired Group, a consultancy specializing in distribution utility investment, performance, and value creation.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I received an undergraduate degree in finance and marketing from Indiana University's Kelley School of Business in 1983, and a master's degree from the Kellogg School of Management at Northwestern University in 1991. My first role in the electric utility industry, beginning in 2001, was as a product development manager with Xcel Energy. I oversaw the development of new demand-side management ("DSM") programs, as well as programs and rates in support of voluntary renewable energy purchases and renewable portfolio standard compliance.

After seven years with Xcel Energy, I established a utility practice for sustainability consulting firm MetaVu. While at MetaVu I utilized my DSM evaluation, measurement and verification ("EM&V") experience to lead two comprehensive evaluations of smart grid deployment performance, including both grid and meter modernization. The first was an evaluation of the SmartGridCity™ deployment in Boulder, Colorado completed for Xcel Energy and filed with the Colorado Public Utilities Commission in 2010,[1] and the second was an evaluation

[1] *SmartGridCity™ Demonstration Project Evaluation Summary*. Exhibit MGL-1 to the testimony of Michael G. Lamb in the Matter of the Public Service Company of Colorado Application for Approval of SmartGridCity Cost Recovery. Filed with the Colorado PUC in 11A-1001E on December 14, 2011. Alvarez et al. Report dated October 21, 2011.

of Duke Energy's Cincinnati-area deployment completed for the Ohio Public Utilities Commission in 2011.[2]

I started the Wired Group in 2012 to focus exclusively on distribution utility performance measurement and ratepayer value creation. In addition to leading the Wired Group, I teach, publish and present at conferences on related topics.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes, I testified on behalf of the Environmental Defense Fund in Docket Nos. E-2, Sub 1142 and E-7, Sub 1146, the most recent Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") rate cases regarding the Companies' "Power/Forward" grid investment plan. My testimony in those cases supported the need for distinct proceedings to develop grid modernization plans, and recommended that stakeholder engagement be utilized to better align the Companies' grid modernization plans and investments with stakeholder priorities, and to increase plan cost-benefit ratios for ratepayers, communities, and the environment.

Q. DID THIS COMMISSION ACCEPT YOUR RECOMMENDATION IN THAT REGARD?

A. Yes, in part. As stated in the Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction issued in Docket No. E-7, Sub 1146, "the Commission directs DEC to utilize an existing proceeding, such as the Integrated Resource Planning and Smart Grid Technology Plan docket, to inform the Commission, and to engage and collaborate with stakeholders to address the myriad of issues raised in the context of Power Forward and the Company's proposed Grid Rider."[3]

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[2] *Duke Energy Ohio Smart Grid Audit and Assessment*. Public Utilities Commission of Ohio Staff Report, public version, filed in 10-2326-GE-RDR on June 30, 2011. Alvarez et al.

[3] *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction.* North Carolina Utilities Commission Docket No. E-7, Sub 1146 (June 22, 2018), p. 149.

Q. HAVE YOU TESTIFIED BEFORE OTHER STATE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified before state utility regulatory commissions in California, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, North Dakota, Ohio, Pennsylvania, and Washington. I have also served clients participating in regulatory proceedings in Colorado, Hawaii, South Carolina, and Virginia. I also co-authored, with Dennis Stephens, a paper on Duke Energy's GIP from the perspective of South Carolina ratepayers,[4] and a similar paper on Dominion's "Grid Transformation Plan."[5] (I note the Virginia SCC largely rejected Dominion's Grid Transformation Plan.)[6] The subject matter in all these proceedings related to utility planning, investment, and performance measurement. My full CV is attached as Alvarez Exhibit 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony critiques the Grid Improvement Plan ("GIP"), a multi-billion-dollar portfolio of investments in the transmission and distribution grid proposed by DEC and DEP (collectively, the "Companies" or "Duke Energy"). The GIP, as proposed in DEC's application in this docket, includes investments in both the DEC and DEP grids.[7] My testimony focuses on the cost-benefit analyses for the GIP, and the testimony of Dennis Stephens focuses on the technical aspects of the GIP.

Q. WHAT IS DUKE ENERGY ASKING THE COMMISSION TO APPROVE WITH REGARD TO THE GIP?

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[4] Alvarez P and Stephens D. *Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers.* Whitepaper developed for GridLab. January 11, 2019.

[5] Alvarez P and Stephens D. *Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders.* Whitepaper developed for GridLab. October 5, 2018.

[6] Virginia State Corporation Commission PUR-2018-00100. Order dated January 17, 2019.

[7] Because the GIP as proposed is a package of investments in both the DEC and DEP grids, I have not attempted to disentangle DEC's investments from the package, and as a result, my testimony generally refers to the "Duke Energy" GIP.

A. Although the testimony and exhibits of DEC Witness Jay Oliver, the Company's primary GIP witness, run over 600 pages, not including workpapers, and provide details on billions of dollars in proposed investments, DEC's application really requests just two GIP-related items: (1) a return on and of capital for GIP assets placed in service during the test year; and (2) deferred accounting on GIP assets placed into service from 2020 through 2022.

Q. HOW IS THE CURRENTLY PROPOSED GIP DIFFERENT FROM THE "POWER/FORWARD" PROPOSAL THAT WAS REJECTED BY THIS COMMISSION?

A. To some extent, the GIP is a scaled-down version of "Power/Forward." Like Power/Forward, Duke Energy proposes to invest billions of dollars in its grid if the Commission grants its preferred cost recovery. Though the GIP is shorter (three years instead of 10) and the total capital cost is lower, nothing precludes Duke Energy from making additional proposals that could equal or exceed Power/Forward in the future. There is less spending on Targeted Undergrounding, though several new programs have been added that, as Witness Stephens' testimony indicates, suffer from the same deficiencies, as they are neither cost-effective nor standard industry practice. I welcome the addition of an integrated Volt-VAR control program (for conservation voltage reduction), though no cost-benefit analysis has been prepared for other added programs.

II. Summary and Recommendations

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY IN THIS PROCEEDING.

A. My testimony begins with context, documenting the lack of a relationship between distribution investments and reliability improvements by United States investor-owned utilities ("IOUs") in recent years. My testimony then provides evidence that the GIP will ultimately cost ratepayers $8.7 billion over 30 years, or $3.5 billion in present value terms. This is 50% greater than the $2.3 billion capital investment Duke Energy presents,[8] resulting from:

- $424.5 million in capital detailed in GIP cost-benefit analyses but not recognized in the 2020-2022 GIP capital schedule;
- $192.5 million in capital for Energy Storage and Electric Transportation presented as GIP programs but not included in 2020-2022 GIP capital schedule totals;
- $1.1 billion in software and communications network replacements during the 30-year GIP benefit period not included in the GIP capital or cost-benefit analyses ($405 million in present value); and
- $4.6 billion in carrying charges ratepayers will have to pay on GIP investments over the next 30 years.

My testimony also warns against the setting of precedents that will result in more sub-optimal capital spending in future years, the ambiguity of GIP capital cost estimates, and the lack of technical or economic "make vs. buy" analyses for $160 million in communications network investment as the "Internet of Things" era approaches.

My testimony then explains how Duke Energy overstates the benefits of the GIP by billions of dollars. My concerns include:

- A variety of aggressive and unsupported assumptions used to calculate many program-specific reliability improvement estimates;
- The manner in which Duke Energy translates reliability improvement estimates into economic benefits, using deeply flawed DOE "cost of service interruptions" data;

[8] *Direct Testimony of Jay Oliver*, Docket No. E-7, Sub 1214 ("*Oliver Direct*"), Exhibit 10, p. 3, "Capital Budget Summary – NC Only".

- The use of inflated primary benefits related to reliability as IMPLAN economic development model inputs, resulting in inflated secondary benefit estimates; and
- The failure of Duke Energy to estimate the detrimental impact of GIP rate increases on North Carolina's economy.

Based on these observations, I conclude that the GIP is a break-even proposition *at best* for ratepayers overall, and is dramatically negative for residential ratepayers in particular. This is because Duke Energy justifies its GIP almost entirely through reliability benefits that will accrue to commercial and industrial (C&I) ratepayers. I also conclude that the GIP's asymmetrical risk profile, with ratepayers taking all risk for benefit delivery and cost overruns, while shareholders earn a rate of return under all scenarios, is inappropriate.

Finally, my testimony examines the superficial nature of Duke Energy's stakeholder engagement efforts, comparing those efforts to a truly transparent, stakeholder-engaged distribution planning and capital budgeting process designed to better align utility, ratepayer, and stakeholder interests. The North Carolina economy's ability to accommodate rate increases is finite, and therefore, Duke Energy grid investments must be contained, and capabilities carefully prioritized, such that the right capabilities are available to an appropriate geographic extent at the right time. Given that rate increases are a finite resource, capital spent poorly today makes less capital available tomorrow for investment in the grid-related components of the North Carolina Clean Energy Plan.[9]

Q. WHAT QUESTIONS DO YOU BELIEVE ARE RAISED BY THE PROPOSED GIP?

A. I believe the key question for the Commission and ratepayers is whether the GIP, if approved, will deliver benefits to North Carolina ratepayers and communities in excess of costs to ratepayers and communities. My testimony, combined with

[9] State Energy Office, Department of Environmental Quality. *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System.* October, 2019.

Witness Stephens's testimony, will help answer this question. In addition, a number of other important questions are prompted by Duke Energy's GIP proposal:

- What is the appropriate balance between affordability and reliability?
- What amount of reliability and resilience should be expected, with associated cost socialization across all ratepayers, versus the amount of reliability and resilience self-insurance individual consumers should be expected to fund based on individual risks and tolerances?
- What is the appropriate investment balance between weather event resilience in the short term and reduction of greenhouse gas emissions impacting the climate in the long term, in line with the state's Clean Energy Plan and Duke Energy's own carbon reduction goals?
- How do the cost and risk of grid investments to accommodate third-party investments in clean distributed energy resources ("DER") compare to the cost and risk of Duke Energy investments in clean generation?
- What is the most appropriate way to evaluate capital-intensive Duke Energy proposals against the purchase of non-capital services from third parties?
- How much of a rate increase due to distribution investments can the North Carolina economy absorb without undue harm to companies, employment, and communities?

These questions should not—and cannot—be answered solely by Duke Energy. Instead, I suggest a truly transparent distribution planning and capital budgeting process, complete with significant and thorough stakeholder input and decision rights, should be employed to answer them. Such a process would help to optimize grid investment in a way that best balances utility, ratepayer, community and stakeholder goals, priorities, and interests.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION IN THIS PROCEEDING?

A. Due to the significant deficiencies and improvement opportunities described in my testimony, my primary recommendation is that the Commission reject Duke Energy's GIP, and establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process for future use in North Carolina. I recommend that upon completion, the new process be used to develop a grid improvement plan that better aligns Company, ratepayer, and stakeholder interests.

Should the Commission reject my primary recommendation, I recommend it adopt the program-specific recommendations Witness Stephens describes as secondary recommendations in his testimony. I concur with all conditions and adjustments Witness Stephens describes for those GIP programs the Commission might approve. Finally, like Witness Stephens, I believe that deferred accounting treatment of GIP costs is unnecessary, and encourages sub-optimal grid investments of the types Witness Stephens identifies in his testimony. Therefore, I recommend the Commission reject DEC's request for deferral of costs for any GIP program the Commission might approve.

III. Historical Context

Q. PLEASE PROVIDE THE HISTORICAL CONTEXT YOU MENTIONED REGARDING DECLINING RELIABILITY DESPITE INCREASING INVESTMENTS IN THE GRID.

A. United States IOUs have increased distribution grid investment by 24% since 2013 despite flat or falling energy use and demand.[10] Over the same period, two key indices of reliability have declined: System Average Interruption Duration Index ("SAIDI")[11] has deteriorated 9%, and System Average Interruption Frequency

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[10] FERC Form 1 data as summarized by the Utility Evaluator, available by subscription at www.utilityevaluator.com.

[11] SAIDI, a measure of service interruptions duration per IEEE Standard 1366.

Index ("SAIFI")[12] has deteriorated 6%.[13] (Note that for SAIDI and SAIFI, lower values represent greater reliability.) This data is presented in Figure 1 below.

Figure 1: Relationship Between Grid Investment and Reliability Without Major Events, U.S. IOUs

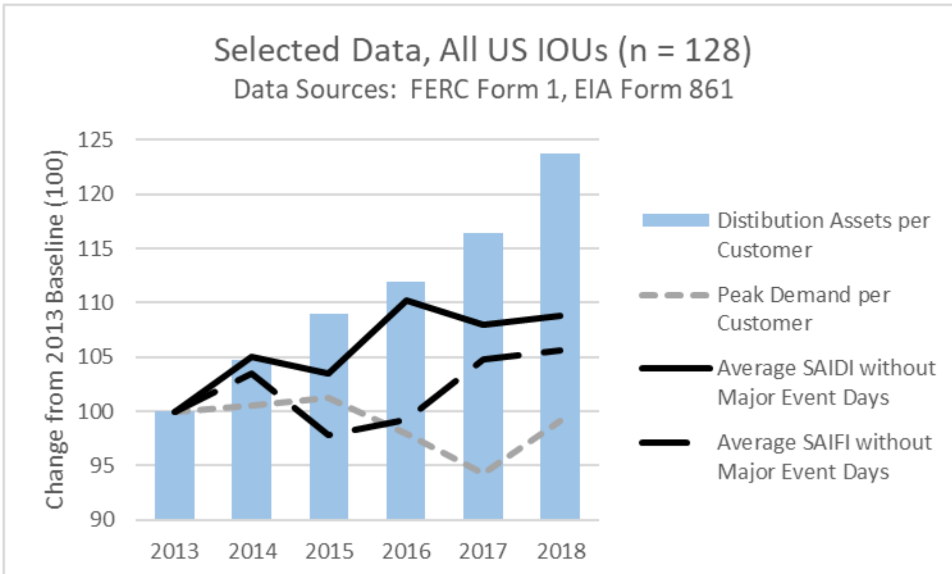

Figure 1 illustrates a counterintuitive caution to regulators: increased distribution investment is not correlated with reliability improvements. This conclusion is consistent with a Department of Energy study on U.S. electric reliability covering years 2002 to 2012.[14] Figure 1 analyzes "clear day" reliability; that is, without major events.[15] Figure 2, below, shows the same comparison, but using reliability measures that include major events. The relationship between distribution investment and improved resilience in the face of major events is even

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[12] SAIFI, a measure of service interruption incidence per IEEE Standard 1366.

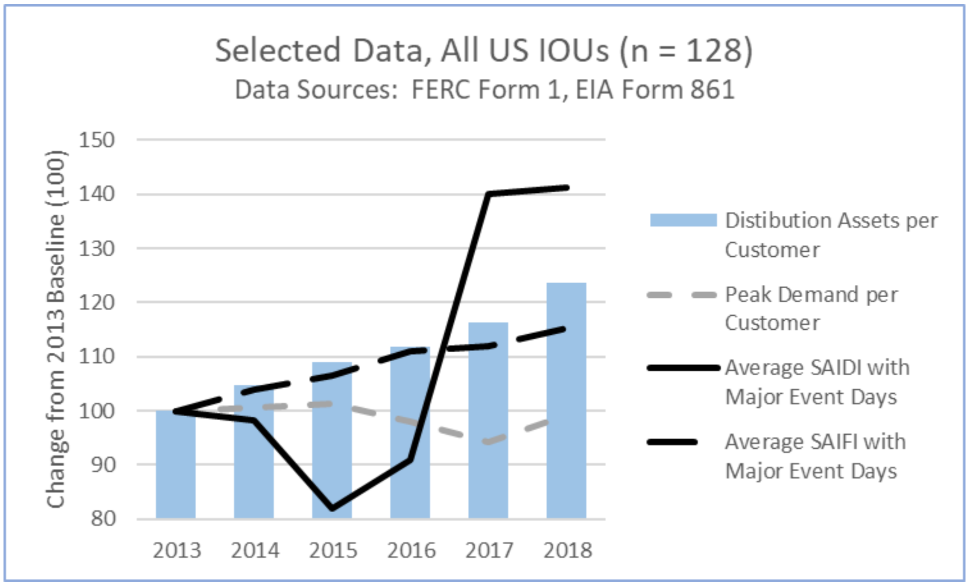
[13] US Energy Information Administration. Data submitted by US investor-owned utilities on Form 861 as summarized by the Utility Evaluator.

[14] Larsen P, LaCommare K, Eto J, and Sweeny J. *Assessing Changes in the Reliability of the U.S. Electric Power System.* Lawrence Berkeley National Laboratory study for the U.S. Department of Energy. August, 2015. P. 37.

[15] "Major events" are almost exclusively severe weather events. Though rare, transmission-level outages outside of distribution utilities' control are also counted as "major events."

more tenuous than the relationship between distribution investment and clear-day reliability.

Figure 2: Relationship Between Grid Investment and Reliability With Major Events, U.S. IOUs



Q. DO YOU CONCLUDE FROM THIS DATA THAT INVESTMENTS IN RELIABILITY OR WEATHER RESILIENCE ARE BAD IDEAS?

A. No. Instead, I believe any of the following may be true: (1) IOU distribution investments have not been focused on the capabilities most likely to improve reliability and resilience; (2) IOU distribution investments have been focused on improving reliability and resilience, but are not succeeding; (3) IOUs, recognizing that deteriorating reliability can help justify large distribution investments, are more accurately reporting poor reliability performance; and/or (4) weather events really are getting more frequent and severe. Proposed grid investments, and in particular grid investment proposals developed outside of the distribution planning processes Witness Stephens describes in his testimony, must be very carefully evaluated and prioritized if benefits to ratepayers are to exceed costs to ratepayers.

IV. The GIP Understates Costs to Ratepayers by Billions of Dollars

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. The $2.3 billion North Carolina capital budget Duke Energy presents in its GIP[16] understates costs to ratepayers by 50%:

- $424.5 million in capital is detailed in GIP cost-benefit analyses but not recognized in the 2020-2022 GIP capital schedule;
- $192.5 million in capital for Energy Storage and Electric Transportation presented as GIP programs are not included in 2020-2022 GIP capital schedule totals;
- $1.1 billion in software and communications network replacement cost during the 30-year GIP benefit period are not included in capital budgets or cost-benefit analyses ($405 million in present value terms); and
- $4.6 billion in carrying charges ratepayers will have to pay on GIP investments over the next 30 years are not included in ratepayer costs.

Other issues related to GIP costs concern me. First is the potential establishment of unwarranted program precedents, particularly as the GIP proposes no program performance measurement. Second is the ill-defined nature of program costs, as illustrated by differences between program capital budgets and cost-benefit analyses. Finally, I am concerned by the significant cost, and insufficient evaluation of options, related to $160 million in capital for new voice and data communications networks Duke Energy proposes.

Q. HOW HAVE YOU DETERMINED THAT DUKE ENERGY'S GIP CAPITAL BUDGET IS UNDERSTATED BY $424.5 MILLION IN CAPITAL SPENDING PLANNED OUTSIDE THE THREE-YEAR PLAN PERIOD?

[16] Oliver Direct, Ex. 10, p. 3, "Capital Budget Summary – NC Only".

A. Duke Energy provided cost-benefit analyses for most of the programs listed in the \$2.3 billion North Carolina GIP Capital Budget Summary.[17] Notably, the capital spending in the cost-benefit analyses is significantly greater than the capital identified in the North Carolina GIP capital budget summary. This is concerning, as it appears that the primary GIP benefits that Duke Energy projects (\$9.241 billion)[18] will require much more capital than Duke Energy presents in the GIP (\$2.3 billion).

Q. WERE YOU ABLE TO EXPLAIN THE DIFFERENCE BETWEEN THE TWO ESTIMATES?

A. To some extent. For example, the totals in the North Carolina GIP Capital Budget Summary did not include \$192.5 million in Energy Storage and Electric Transportation program capital (more on that below). In addition, the cost-benefit analyses for some programs, such as Transmission programs, included capital for both North and South Carolina. After adjusting for these factors, however, the capital specified in the cost-benefit analyses was still much larger than presented in the GIP capital budget summary.

Q. WERE YOU ABLE TO IDENTIFY THE REMAINING DIFFERENCES BETWEEN THE CAPITAL IN THE COST-BENEFIT ANALYSES AND THE CAPITAL IN THE GIP CAPITAL BUDGET SUMMARY?

A. Yes, and I categorize them into three "buckets" of spending. The first bucket is \$234.4 million in program capital spending planned in the cost-benefit analyses prior to the 2020-2022 period covered by the GIP capital budget summary. The second bucket consists of differences I was unable to reconcile during the GIP capital budget period years of 2020-2022. I found the capital in the cost-benefit analyses differed from the capital presented in the GIP capital budget for multiple programs. Some programs had much more capital in the GIP than in the corresponding cost-benefit analyses, but for other programs the reverse was true. These differences concern me, as I will discuss further below, but the net of these

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[17] Oliver Direct, Ex. 7, multiple Microsoft Excel® workbooks.

[18] Oliver Direct, Ex. 8, page 3.

differences is that the capital in the 2020-2022 GIP capital budget summary exceeds the capital in the cost-benefit analyses by $53.5 million. The third bucket consists of spending beyond the GIP capital budget period, amounting to $243.6 million from 2023 to 2027, and consisting mainly of integrated volt-VAR control, transmission hardening & resilience, and targeted undergrounding program capital. In total, the capital spending required to secure the benefits projected in the cost-benefit analyses, including $192.5 million in energy storage and electric transportation capital missing from GIP capital budget totals, is $616.9 million (26.6%) higher than the $2.319 billion presented in the North Carolina 2020-2022 GIP capital budget summary.

Q. DO YOU FIND IT PROBLEMATIC THAT DEC DID NOT INCLUDE THE $192.5 MILLION ENERGY STORAGE AND ELECTRIC TRANSPORTATION CAPITAL IN NORTH CAROLINA GIP CAPITAL BUDGET TOTALS?

A. To me, it simply illustrates another example of DEC underestimating GIP costs. It is true that these programs are being evaluated in other dockets. However, as DEC describes these programs as part of its GIP,[19] and as ratepayers will be required to pay for these programs if approved, I believe it is appropriate to include capital from these programs as part of the costs DEC ratepayers will have to pay for discretionary spending that is outside "business as usual." It seems disingenuous to me to describe these as GIP programs, but to exclude their costs from GIP capital program totals.

Q. EXPLAIN WHY DUKE ENERGY'S FAILURE TO INCLUDE COSTS TO REPLACE SHORT-LIVED ASSETS, SUCH AS SOFTWARE AND COMMUNICATIONS INFRASTRUCTURE, UNDERSTATES COST BY $1 BILLION.

A. Field hardware assets in Duke Energy's GIP generally have an estimated useful life of at least 25-35 years. As is appropriate, Duke Energy estimated benefits for each

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[19] Oliver Direct, Ex. 4, pages 13-15, and Ex. 10, pages 3, 47, and 84.

program individually, based on the expected 25-35 year useful life of program assets. The exceptions are software and communications networks, which have useful lives of 5-10 years.[20] Presumably, communications networks and software are essential to securing the benefits Duke Energy projects in program cost-benefit analyses; otherwise, they would not be included in the GIP (new data and voice communications networks are even described as "Mission Critical").

Unfortunately, GIP cost-benefit analyses include no capital costs for replacements of these communication networks and software packages, with useful lives of 5-10 years, over the course of the 25-35 year benefit periods assumed in the cost-benefit analyses, thus resulting in a significant cost understatement. As shown in Table 1, below, and assuming a 2.5% compound annual inflation rate, I estimate the understatement to be at least $1 billion, or $405.3 million in present value terms (discounted at Duke Energy's 6.8% weighted average cost of capital).

Table 1: Software and Communications Network Capital Costs Missing from Duke Energy GIP Cost-benefit Analyses

Program/Sub-Component	Present Value	2027	2032	2037	2042	2047
ADMS (Self-Optimizing Grid)	53,722,192	-	62,369,028	-	79,837,629	-
Enterprise Communications	233,553,437	-	271,144,948	-	347,088,457	-
Enterprise Applications	78,380,613	31,506,325	35,646,514	40,330,759	45,630,552	51,626,781
ISOP Programs	18,717,674	7,523,865	8,512,562	9,631,183	10,896,799	12,328,728
DER Dispatch Tool	20,960,980	8,425,597	9,532,790	10,785,476	12,202,777	13,806,322
Total	405,334,895	47,455,786	387,205,842	60,747,418	495,656,214	77,761,831

Q. PLEASE SUM UP THE AMOUNTS YOU HAVE IDENTIFIED THAT ARE MISSING FROM THE GIP CAPITAL BUDGET SUMMARY.

[20] DEC response to NCJC Data Request No. (hereinafter, "NCJC DR") 5-3, attached as Alvarez Exhibit 2. (References to DEC responses to data requests are to those served in the current docket.)

A. I have identified $1.0 billion in capital, including $616.9 million in program capital and $405 million (present value) in communications network and software replacement capital, that is missing from Duke Energy's $2.3 billion budget.

Q. HAVE YOU ESTIMATED THE REVENUE REQUIREMENT OF THE GIP?

A. Yes. Using assumptions that DEC employed to calculate its revenue requirement in this rate case,[21] I estimated the revenue requirements associated with GIP capital and O&M spending as presented in program cost-benefit analyses, plus the capital budgets of programs for which no cost-benefit analyses were completed (including energy storage and electric transportation), plus the missing communications and software replacement costs described above. The highlights of my calculations are presented in Alvarez Exhibit 10. I estimate the total GIP revenue requirement over 30 years to be $8.7 billion, or $3.5 billion in present value terms. This is 50% higher than the $2.3 billion Duke Energy presents as the capital cost of the program in the GIP capital budget. If the Commission is interested in comparing the present value of GIP program benefits to GIP ratepayer costs, I recommend it use my $8.7 billion nominal cost estimate, or my $3.5 billion present value estimate, in place of the $2.3 billion found in the GIP capital budget.

Q. WHAT DOES THIS MEAN IN TERMS OF RATE INCREASES?

A. In this rate case DEC is requesting annual revenues of $5.2 billion, including $1.2 billion in fuel (and purchased power) costs.[22] According to my estimate, the GIP revenue requirement will peak in 2023 at $363.1 million. If the GIP revenue requirement is split by customer count between DEC (2.005 million) and DEP (1.412 million), the DEC revenue requirement will be 58.7% of the total, or $213.15 million. This is a 4.1% increase in the DEC revenue requirement and a 5.3% increase in the DEC non-fuel revenue requirement. Given that these GIP rate increases will be in addition to whatever other increases DEC requests for business

[21] Direct Testimony of Jane McManeus, NCUC E-7 Sub 1214 ("McManeus Direct"), Exhibit 1.

[22] McManeus Direct, Exhibit 1, tab "2018 Exh 1 Page 1", column 6.

as usual cost increases, I conclude that the rate increases resulting from the GIP will be significant.

Q. YOU MENTIONED A CONCERN ABOUT THE INVESTMENT PRECEDENTS THE GIP ESTABLISHES. PLEASE EXPLAIN.

A. Although the proposed GIP capital investment is large, each program replaces just a fraction of the installed base of assets of the type targeted by each program. My concern is that, once deferral accounting is approved for a program, the approval will be interpreted as tacit endorsement of the technical or economic merits of the program. This GIP may be only the first of several extraordinary grid investment proposals the Commission will be asked to consider in the next decade, and these proposals are likely to consist largely of continuations of previously approved programs. The fact that the GIP is, in many ways, a 3-year, $2.3 billion subset of the 10-year, $13 billion Power/Forward plan proposed in the last Duke Energy rate cases should cause the Commission significant concern in this regard. If the Commission approves the GIP in its entirety, the number of assets remaining available for future replacement are listed in Table 2, below.

Table 2: Assets Still Available for Replacement if the GIP Is Approved

Program (count of target assets replaced per cost-benefit analyses)[23]	Assets remaining Count (Percent)
Targeted Undergrounding (235 backyard line miles)[24]	Unknown; likely in excess of 90%
44kV Lines (80 miles)[25]	2,720 (97.1%)
Transformer Bank Replacement (151 substation transformers)[26]	5,766 (97.4%)
Oil-filled Circuit Breaker Replacement (1,365 substation breakers)[27]	3,285 (70.6%)
Substation physical security (27 substations)[28]	2,098 (99.2%)

Q. YOU MENTION THAT GIP COSTS ARE "ILL-DEFINED". PLEASE SUPPORT THIS CLAIM, AND EXPLAIN WHY IT CONCERNS YOU.

A. As I mentioned earlier, there are many differences between the capital costs provided in the GIP capital budget and the total capital costs found in GIP cost-benefit analyses. As just one of many examples, the GIP capital budget for "Oil Breaker Replacement" is just over $200 million;[29] the capital amounts provided in cost-benefit analyses, after removing portions that apply to South Carolina, is only

[23] Oliver Direct, Ex. 7, multiple Microsoft Excel® workbooks.

[24] DEC and DEP do not track miles of line through residential backyards. DEC response to NCJC DR 8-24 and DEP response to NCJC DR 5-22, attached as Alvarez Exhibit 3. (References to DEP responses to data requests are to those served in Docket No. E-2, Sub 1219.) My assessment that the proportion of backyard overhead line miles yet to be undergrounded is "likely well over 90%" is based on an estimate that the program proposes to underground just 235 miles ($200 million in capital cost divided by $850,000 per mile, from Oliver Direct Ex. 7 workbook "TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx"), while Duke Energy is thought to have thousands of miles of backyard overhead lines.

[25] DEC response to NCJC DR 8-01 and DEP response to NCJC DR 5-01, attached as Alvarez Exhibit 4.

[26] DEC response to NCJC DR 8-26 and DEP response to NCJC DR 5-17, attached as Alvarez Exhibit 5.

[27] DEC response to NCJC DR 8-25 and DEP response to NCJC DR 5-16, attached as Alvarez Exhibit 6.

[28] DEC response to NCJC DR 2-05, attached as Alvarez Exhibit 7.

[29] Oliver Direct, Ex 10, page 3, line "Oil Breaker Replacements".

$106.6 million.[30] This is significant, particularly as DEC never really specifies how much the GIP program will cost.[31] If deferral accounting is approved, we do not know what DEC (or DEP) will spend on the GIP, and how the spending will be split among the programs. This ambiguity is extremely concerning to me, and I believe it should concern the Commission as well. How will the Commission be able to hold DEC accountable for Oil Breaker costs, when it does not know how many Oil Breakers Duke Energy will actually replace, or how much capital it will spend to do so? What governs Oil Breaker capital spending: the GIP capital budget, or the capital in the cost-benefit analysis? Further, changes to the mix of programs and capital within the GIP will impact GIP benefits; but if the mix changes, what is the corresponding impact to projected benefits? The cost caps and operating audits Witness Stephens recommends in his testimony will go a long way to improving Duke Energy GIP cost and benefit accountability in light of these ambiguities.

Q. PLEASE PROVIDE SUPPORT FOR YOUR ASSERTION THAT DUKE ENERGY DID NOT SUFFICIENTLY EVALUATE OPTIONS RELATED TO $160 MILLION IN CAPITAL FOR NEW VOICE AND DATA COMMUNICATIONS NETWORKS.

A. I believe the policy of evaluating potentially lower-cost third-party "non-wires alternatives" to capital investment in the grid should be extended to communications networks. In discovery, DEC admitted that Duke Energy had not evaluated alternatives to proprietary development and ownership of two new communications networks it wants to build, for voice and data communications,[32] at costs of $52 million and $107 million, respectively.

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[30] Oliver Direct Ex 7, "Trans_Oil Breaker_DEC_NC-SC_19-22_vF_rev3 8-2-19.xlsx" (less 18.7% for South Carolina) and "Trans_Oil Breaker_DEP_NC-SC_19-22_vF_rev3 8-2-19.xlsx" (less 9.3% for South Carolina).

[31] DEC response to NCJC DR 5-4, attached as Alvarez Exhibit 8.

[32] DEC responses to North Carolina Sustainable Energy Association Data Request No. (hereinafter, "NCSEA DR") 2-52 (d) and 2-53 (3), attached as Alvarez Exhibit 9.

Q. DID YOU ASK DEC WHY ALTERNATIVES TO PROPRIETARY NETWORK DEVELOPMENT WERE NOT EVALUATED?

A. Yes. In discovery, the Company responded that third-party networks didn't meet minimum technical standards.[33] However, stakeholders have no way of knowing whether the technical standards are appropriate, or whether they have been set as an unnecessarily high bar, so as to make third-party satisfaction of them impossible. Given that Duke Energy is providing safe and reliable electric service with the voice and data communications networks it is already operating, it seems prudent to conduct a detailed investigation and evaluation before approving a $160 million capital investment. I note that this is precisely the kind of distribution investment decision that illustrates the value of a transparent, stakeholder-engaged distribution planning and capital budgeting process.

Q. WHY DO YOU QUESTION DUKE ENERGY'S STATEMENT THAT THIRD-PARTY NETWORKS COULDN'T MEET TECHNICAL STANDARDS?

A. My concern is based on experience and anecdotal evidence, but at the very least, these point to the need for additional investigation and evaluation. For example, one critical utility concern is that in an emergency, third-party networks will be swamped with calls, making utility use of the network during a service restoration effort impossible. However, third parties' 4G cellular networks now offer "network slicing" capabilities that dedicate and reserve part of a physical network's bandwidth to various clients. AT&T's FirstNet service, developed specifically to meet the needs of first responders like police and fire departments, addresses this concern through network slicing.[34] I also note that at least one state utility regulatory commission, Rhode Island, is questioning multi-hundred million dollar investments by a utility in a proprietary network when alternatives may be

[33] Ibid.

available.[35] I am also aware of at least two investor-owned utilities, Xcel Energy[36] and Hawaiian Electric,[37] which use public 4GLTE networks for at least some grid data communications. I note that non-profit utilities, which are not subject to capital bias, utilize third party networks to a much greater degree than investor-owned utilities do. The burden of proof that an investment is reasonable and prudent falls on utilities. When $160 million is proposed for services already available from third parties, time spent evaluating reasonableness and prudency in advance is time well spent.

V. The GIP Overstates Benefits to Customers by Billions of Dollars

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. The GIP will deliver only a small fraction of the benefits that Duke Energy projects. First, Duke Energy overstates primary GIP economic benefits from reliability, at both the program-specific and systemic levels. Duke Energy also relies inappropriately on the IMPLAN model to estimate secondary, economic-development benefits of reliability improvements it attributes to the GIP. These benefits should be ignored entirely. Not only are they inflated, they do not take into account the detrimental impact to the North Carolina economy of the GIP rate increases discussed in the previous section of testimony. Further, the over-estimated benefits of some programs provide "cover" for programs that are not cost-effective. Although Duke Energy presents the GIP as a package, that package consists of programs that should be examined individually.

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[35] Rhode Island PUC 4770 and 4780. Settlement Agreement dated June 6, 2018, page 49: "The Updated AMF Business Case for Rhode Island . . . will include an evaluation of shared communications infrastructure and various ownership models for key AMF components."

[36] Lysaker D and Markland D. *Xcel Energy Leverages 4G LTE to Enable Reliable, High Speed Connectivity to Distribution End Points.* Green Tech Media webcast July 31, 2017. (https://www.greentechmedia.com/webinars/webinar/xcel-energy-leverages-4g-lte-to-enable-reliable-high-speed-connectivit)

[37] Alleven, M. *Verizon taps Cat M1 network for smart grid utility services.* Fierce Wireless article posted July 19, 2018. (https://www.fiercewireless.com/wireless/verizon-taps-cat-m1-network-for-smart-grid-utility-services)

Q. PLEASE CHARACTERIZE THE GIP BENEFITS DUKE ENERGY PROJECTS.

A. Duke Energy projects two types of benefits from its GIP. Primary benefits are the direct benefits DEC, DEP or its ratepayers will receive directly, in the form of reliability improvements, O&M cost reductions, energy conservation, etc. Duke Energy projects the present value of these benefits, delivered over the next 30 years or so, to be $9.2 billion.[38] Duke Energy then adds follow-on, secondary benefits it projects will accrue to the North Carolina economy as a result of the primary benefits. Duke Energy calls these IMPLAN benefits, named after the tool used to calculate them, and estimates their present value at $7.2 billion.[39] I will critique the primary benefits first, and critique the IMPLAN benefits later in this section.

My critique of primary benefit estimates will focus on the economic benefits of anticipated reliability improvements, as these benefits constitute 88% of the GIP benefits Duke Energy projects.[40] It is important to understand that of these reliability-related benefits, Duke Energy estimates that more than 97% will accrue to Commercial and Industrial ("C&I") ratepayers.[41]

Q. HOW DOES DUKE ENERGY ESTIMATE THE ECONOMIC BENEFITS RELATED TO GIP RELIABILITY IMPROVEMENTS?

A. Duke Energy used a two-step process to estimate the economic benefits related to GIP reliability improvements. The first step is to estimate the impact of a program on the frequency of interruptions (customer interruptions, or "CI") and the duration of interruptions (customer minutes interrupted, or "CMI"), which is calculated by rate class on an asset-specific basis (such as a circuit). The second step is to translate these reliability improvements into economic benefits, by multiplying the

[38] Oliver Direct, Ex 8, page 3.

[39] Ibid.

[40] My analysis of multiple, program-specific cost-benefit analyses provided in Oliver Direct, Ex. 7, attached as Alvarez Exhibit 10.

[41] Ibid.

projected CI or CMI reductions by rate class by estimates of economic impact per CI or CMI by rate class.[42] The exception to this approach is for the projects that comprise the transmission hardening and restoration program. For those projects, the economic benefits from reliability improvements were calculated using Duke Energy's risk-informed investment decision support software, Copperleaf C-55,[43] which employs the same source for estimates of economic impact per CI or CMI that Duke Energy uses for all other reliability improvement benefit calculations.

Q. WHAT IRREGULARITIES IN THIS TWO-STEP RELIABILITY BENEFIT ESTIMATION PROCESS LEAD YOU TO CONCLUDE THAT DUKE ENERGY HAS OVERSTATED THESE BENEFITS?

A. Witness Stephens and I have identified multiple program-specific assumptions leading to overstated reliability improvement estimates in step 1 of the process. I have also identified multiple concerns with the underlying research that make its estimates of economic impact per CI or CMI unsuitable for use in translating reliability improvements into economic benefits in step 2 of the process. These irregularities indicate that the primary GIP benefit estimates provided in Duke Energy's cost-benefit analyses are dramatically overstated.

A. Program-Specific Assumptions Leading to Overstated Reliability Improvements

Q. PLEASE DESCRIBE THE PROGRAM-SPECIFIC ASSUMPTIONS LEADING TO OVERSTATED RELIABILITY IMPROVEMENT ESTIMATES.

A. Witness Stephens and I have identified multiple programs with inflated reliability improvement estimates, including transmission hardening and restoration, targeted

[42] These estimates are based on a 2013 update of research completed in 2009 by Lawrence Berkeley National Laboratories ("LBNL") for the US Department of Energy ("DOE"). Sullivan M, Schellenberg J, and Blundell M. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. January, 2015.

[43] I note that neither Witness Stephens nor I were able to review this software, or how it was used to calculate the economic benefits of the transmission hardening and resilience program, in advance of the testimony due date.

undergrounding, long duration interruption/high impact sites, transformer bank replacement, and oil-filled breaker replacement programs. Duke Energy's cost-benefit analyses project that these five programs will deliver almost 75% of the GIP's reliability-based economic benefits.

Q. DESCRIBE THE ASSUMPTIONS LEADING TO OVERSTATED RELIABILITY IMPROVEMENT ESTIMATES IN THE TRANSMISSION HARDENING AND RESTORATION PROGRAM.

A. The largest part of the transmission hardening and restoration ("TH&R") program, representing 83.2% of program costs and 95.5% of program benefits not related to substation flood mitigation,[44] consists of rebuilding DEC's existing 44kV transmission lines, including new support structures, new conductor, and new static lines. In fact, Duke Energy projects these DEC projects alone will amount to $1.899 billion in primary benefits, or 20.6% of all GIP benefits.[45]

Unlike the cost-benefit analyses for any other GIP programs/sub-components, Duke Energy calculated the reliability-related benefits of its 44kV rebuild sub-components using a proprietary software program from Copperleaf, the C55 "Investment Decision Optimization Solution." One software feature is that "asset condition data and degradation curves can be modeled to determine the overall risk profile of your assets." The software is designed to help utilities work with stakeholders to "quickly come to agreement on the best overall investment strategy."[46]

My concern is that the C55 software, the data Duke Energy is inputting regarding asset condition, the asset degradation curves being employed, or some combination of the three, is dramatically overstating transmission hardening and restoration benefits. For example, Witness Stephens believes strongly that asset

[44] Oliver Direct, Ex 8, page 2,

[45] Ibid.

[46] Copperleaf C55 software brochure available at https://resources.copperleaf.com/brochures-2/c55-investment-decision-optimization

degradation curves should be based solely on Duke Energy's historical asset failure rates. In discovery, Duke Energy stated that in the last five years it had only 8 failures 8,400 miles of 44kV conductor,[47] a failure rate of just 0.02% per line mile per year (2 in 10,000 likelihood). Duke Energy also stated that in the last five years it had only 85 failures of all types of 44kV equipment (static lines, switches, support structures, insulators, etc.) out of 2,800 44kV line miles,[48] a failure rate of just 0.6% per line mile per year (60 in 10,000 likelihood). Assuming historical failure rates continue into the future – and DEC has provided no evidence as to why they should not – there is no possibility that the reliability benefits associated with just 1.6 44kV conductor failures every year for all of DEC, and just 17 44kV equipment failures every year for all of DEC, will provide the approximately $200 million in average annual primary reliability benefits required for a $1.899 billion present-value primary benefit estimate.

Q. DESCRIBE THE ASSUMPTIONS LEADING TO OVERSTATED RELIABILITY IMPROVEMENT ESTIMATES IN THE TARGETED UNDERGROUNDING PROGRAM.

A. Duke Energy projects $2.041 billion in present-value, or 22% of the total projected primary GIP benefits, will be delivered by the targeted undergrounding ("TUG") program.[49] Though the TUG program is dedicated to undergrounding overhead lines that currently run through residential backyards, Duke Energy's cost-benefit analyses project that over 98% of the benefits from targeted undergrounding will accrue to commercial and industrial ("C&I") ratepayers. Duke Energy claims that every fault in overhead lines in residential areas results in 2.7 momentary outages upstream of the fault, on portions of circuits with large numbers of C&I ratepayers. This 2.7:1 ratio is based on a relationship established by comparing the count of

[47] DEC response to NCJC DR 8-27 and DEP response to NCJC DR 5-18, attached as Alvarez Exhibit 11.

[48] DEC response to NCJC DR 8-28 and DEP response to NCJC DR 5-19, attached as Alvarez Exhibit 12.

[49] Oliver Direct, Ex 8, column "Total NPV Benefits" (primary).

system-wide momentary interruptions to the count of system-wide sustained interruptions each year from 1997 to 2010.[50]

Not only is this ratio based on old data, no causal relationship has been established. In other words, it has not been shown that outages in specific residential areas cause momentary outages for upstream C&I ratepayers on the same circuit. It is inappropriate to base a benefit from specific projects on specific circuits and neighborhoods on a system-wide statistical relationship between sustained and momentary outages for which no causation can be shown. If Duke Energy wishes to project upstream momentary outage avoidance for C&I ratepayers as a benefit of undergrounding, and to justify $114.5 million in investment on that basis, it should be required to provide historical momentary outage data specific to those circuits and upstream C&I ratepayers.

Q. DID YOU REQUEST HISTORICAL MOMENTARY OUTAGE DATA IN DISCOVERY?

A. Yes. Duke Energy stated that it does not even monitor momentary interruptions, and has not since 2010.[51] Therefore, Duke Energy cannot provide any data indicating that C&I ratepayers can realistically expect any reduction in momentary outages, let alone the sizes of those reductions. Nor can Duke Energy establish a baseline of pre-undergrounding momentary interruption data for subsequent evaluation of reliability improvements from targeted undergrounding. For all of these reasons, I believe the reliability improvement estimates Duke Energy projects from the TUG program to be vastly overstated.

Q. DESCRIBE THE ASSUMPTIONS LEADING TO OVERSTATED RELIABILITY IMPROVEMENT ESTIMATES IN THE LONG DURATION INTERRUPTION/HIGH IMPACT SITES PROGRAM.

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[50] DEC responses to NCSEA DR 3-11 (attachment "1997-2010 DEC SAIFI and MAIFI.xlsx") and NCJC DR 5-32, attached as Alvarez Exhibit 13.

[51] DEC response to NCJC DR 5-32, attached as Alvarez Exhibit 14.

A. The long duration interruption/high impact sites ("LDI/HIS") program consists of adding redundant circuits to communities or high impact sites currently served by only one circuit. Redundant circuits do indeed provide a back-up source of power should the primary source fail and can reduce the duration of interruptions. My concerns relate to the value Duke Energy placed in its benefit projections on outage durations shortened through back-up power.

Similar to other GIP programs, Duke Energy projects that 99% of the reliability benefits from the LDI/HIS program will accrue to C&I ratepayers. As I will describe later in this testimony, I believe the economic benefits Duke Energy assigns to reliability improvements for all commercial and industrial ratepayers to be excessive. However, since the focus of the LDI/HIS program is long-duration interruptions, the economic benefit Duke Energy assigned to avoidance of lengthy outages is particularly critical to the calculation of the LDI/HIS program benefits.

In general, Duke Energy's estimates of the value of reliability improvements (i.e., "$ per event") come from secondary research conducted by the U.S. Department of Energy in 2009. This research did not address service outages longer than 8 hours in duration. In 2013, the values were updated for two more recent surveys of small numbers of C&I ratepayers, only one of which addressed outages as long as 16 hours. To estimate the benefits of lengthy (defined by Duke Energy as 96 hours) outages avoided, Duke Energy simply extrapolated the difference between the cost of an 8-hour duration and the cost of a 16-hour duration to 96 hours. This overstates benefits in two ways. First, the 16-hour cost estimate is questionable due to a small sample size. Second, such extrapolation is inappropriate. The authors specifically advise against using the results of their research to estimate the costs to ratepayers of longer duration outages, stating that the study "focuses on the direct costs that ratepayers experience as a result of relative short power interruptions of up to 24 hours at most."[52] In the 2009 research

[52] Sullivan M, Schellenberg J, and Blundell M. Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States. Values for LBNL 2009 secondary research updated in 2013. January, 2015. P. 48.

data, it became apparent that as the length of an outage grows longer, the costs ratepayers incur per hour of outage fall. This is because over longer outages, businesses implement contingency plans. Table 3 below, based on the 2009 research data, illustrates this dynamic.[53]

Table 3: Cost per Minute of Outage for Various Durations, C&I Customers

	Under 30 Minutes	1 hour	4 hours	8 hours
Medium & Large C&I	$508/minute	$297/minute	$164/minute	$175/minute
Small C&I	$17/minute	$11/minute	$8/minute	$10/minute

Though it is clear from the 2009 research that the impact per minute falls as outage duration grows, Duke Energy's extrapolation of the 2013 research findings to 96 hours does not take this fact into account.

Q. DO YOU HAVE OTHER CONCERNS REGARDING LDI/HIS PROGRAM BENEFIT OVERSTATEMENTS?

A. Yes. I also believe the reliability improvement estimates to be overstated. For example, while the average historical duration of outages during major event days averaged 16-21 hours for the recent 10-year period Duke Energy analyzed,[54] reliability improvements appear to be based in part on reductions in outage durations of 96 hours. Further, reliability improvements are based on "ballpark" percentages of duration improvement for each of the 131 projects identified in the

[53] Sullivan M, Mercurio M, and Schellenberg J. Estimated Value of Service Reliability for Electric Utility Customers in the United States. Secondary research completed by LBNL for the US DOE. June, 2009. Page xii.

[54] Multiple workbooks from Oliver Exh. 7, including LDI_DEC-DEP_NC_2019_Consolidated_vF 5-10-19.xlsx; LDI_DEC-DEP_NC_2020_Consolidated_vF_rev1 7-9-19.xlsx; LDI_DEC-DEP_NC_2021_Consolidated_vF_rev1 7-9-19.xlsx; and LDI_DEC-DEP_NC_2022_Consolidated_vF_rev1 7-9-19.xlsx; tab "Project-Outage-Pastedata"; average of column "MED 10-year CMI" divided by average of column "MED 10year CI".

LDI/HIS program without any documentation or support. More than 90% of these "ballpark" duration improvements were estimated at 50%, 80%, 90%, or 95%; less than 10% of LDI/HIS projects were estimated to improve outage durations by 33% or less.[55]

Q. DESCRIBE THE ASSUMPTIONS LEADING TO OVERSTATED ECONOMIC BENEFIT ESTIMATES IN THE TRANSFORMER BANK REPLACEMENT PROGRAM.

A. Unlike most other GIP programs, for which benefits stem almost entirely from reliability improvements, the benefits of the transformer bank replacement program consist of about 50% reliability benefits and 50% avoided asset replacement benefits. Both are overstated. For example, DEC reliability benefits are based on an estimate that 26 of the 50 transformer banks to be replaced would fail between now and 2034.[56] This projected 52% failure rate is extremely high given DEC's historical average annual substation transformer failure rate of 0.2% (2 in 1,000 likelihood) over the last 5 years.[57]

The extremely high projected failure rate relative to historical actuals also overstates asset replacement benefits. Duke Energy should not count as benefits the cost of avoided replacement of assets that would not likely have failed. Finally, there is no value in prospective replacement of transformers, as there is no need to guess which transformers might fail. As Witness Stephens testifies, it is standard industry practice to test substation transformer oil to identify for replacement those transformers with a relatively high likelihood of failure.[58]

[55] Ibid, column "Estimated % decrease in event duration".

[56] Oliver Direct, Ex. 7, workbook "Trans_Transformer Bank_DEC_NC-SC_19-22_vF_rev3 8-2-19.xlsx', tab "Bank Replacement Data – DEC" (26 transformers) and tab "Bank Replacement Program – DEC" (50 transformers).

[57] DEC response to NCJC DR 8-26, included as Alvarez Exhibit 5.

[58] Direct testimony of Dennis Stephens on behalf of NCJC et al., p. 34 at line 18.

Q. DESCRIBE THE ASSUMPTIONS LEADING TO OVERSTATED RELIABILITY IMPROVEMENT ESTIMATES IN THE OIL-FILLED BREAKER REPLACEMENT PROGRAM.

A. Like transformers, oil-filled circuit breakers can be tested to identify those that should be replaced. As Witness Stephens testifies, this is standard practice for circuit breakers. So, as with transformers, there is no reliability improvement or avoided asset replacement value associated with prospective replacement of oil-filled breakers. Instead, breakers should simply be tested and replaced as indicated by test results. To illustrate the benefit overstatement, DEC reports that the historical average annual failure rate for all types of substation breakers over the last five years is just 0.0625% (6.25 in 10,000 likelihood).[59] Yet Duke Energy estimates that of the 995 DEC oil-filled circuit breakers proposed for prospective replacement, 696, or 70%, would have failed by 2032.[60]

B. Systemic Assumptions Leading to Overstatements of Benefits

Q. WHAT ARE YOUR CONCERNS WITH THE ESTIMATES OF ECONOMIC IMPACT PER CI OR CMI BY RATE CLASS THAT DUKE ENERGY USES TO TRANSLATE RELIABILITY IMPROVEMENTS INTO ECONOMIC BENEFITS?

A. I have many. Of the economic benefits from reliability improvements that Duke Energy projects, 97% are projected to accrue to C&I ratepayers, making the estimates of economic impact per CI or CMI for these ratepayers particularly critical to the GIP benefit calculations overall. My concerns about these estimates, which are likely to lead to overstated economic benefits for nonresidential ratepayers and the GIP overall, include:

- The estimates are based on a limited number of surveys of manufacturing and retail ratepayers only, conducted decades ago;

[59] DEC response to NCJC DR 8-25, attached as Alvarez Exhibit 6.

[60] Oliver Direct Exh. 7 workbook Trans_Oil Breaker_DEC_NC-SC_19-22_vF_rev3 8-2-19.xlsx, tabs “Oil Breaker Program – DEC” (995 breakers) and “Oil Breaker Data – DEP” (676 breakers).

- The definition of a "large" C&I ratepayer is very small, increasing the large C&I ratepayer count to which avoided cost estimates are multiplied; and
- There is no consistency in how survey respondents took back-up generation and uninterruptible power supplies into account when completing surveys.

Q. PLEASE EXPLAIN HOW SURVEY ADMINISTRATION OVERSTATES ECONOMIC BENEFIT ESTIMATES.

A. The survey data, from a 2009 secondary research project, cannot be used in the manner Duke Energy is using it to translate reliability improvements into economic benefits.[61] It consisted of review and analysis of the results of just 34 surveys of commercial and industrial ratepayers conducted by only 10 utilities from 1989 to 2005. The survey data is old, and also suffers from geographic bias, with no surveys conducted by utilities in Mid-Atlantic or Northeastern states. In addition, only manufacturing and retail ratepayers were surveyed. All other types of C&I ratepayers—service businesses, healthcare facilities, agricultural businesses, non-profit facilities, government facilities—were excluded. Finally, the size of the total sample set is extremely small. By my estimate, the economic impacts of service outages on C&I ratepayers is almost certain to be based on less than 10,000 manufacturing and retail C&I ratepayers surveyed from 1989 to 2005. Though the economic impacts were updated in 2013 through the addition of another 20,000 observations – likely only an additional 4-5,000 C&I ratepayer surveys – this effort does not fix the significant survey administration flaws.

In sum, the data is old, geographically biased, and biased towards manufacturing and retail businesses, which likely have the highest service interruption costs of C&I industry segments. I do not believe the Commission should rely upon C&I economic benefit estimates based on limited C&I ratepayer survey data.

[61] Sullivan M, Mercurio M, and Schellenberg J. Estimated Value of Service Reliability for Electric Utility Customers in the United States. Secondary research completed by LBNL for the US DOE. June, 2009. Page xii..

Q. PLEASE EXPLAIN HOW SURVEY INCONSISTENCIES REGARDING BACK-UP GENERATION AND UNINTERRUPTIBLE POWER SUPPLIES OVERSTATE ECONOMIC BENEFIT ESTIMATES.

A. The authors of the DOE secondary research admit that surveys used to collect outage cost data did not address the availability of back-up generation and uninterruptible power supply ("UPS") systems in a consistent way.[62] A failure to consider the impact-reducing effects of back-up generation and UPS systems when estimating the costs of service outages to C&I ratepayers clearly results in overstated benefit estimates, because most facilities now have such systems. A more recent, unbiased survey of C&I ratepayers, across 49 different facility types, indicates that 80% had back-up generation available, 61% had UPS systems available, and 59% had both.[63]

Q. PLEASE EXPLAIN HOW THE DEFINITION OF A "LARGE" C&I RATEPAYER OVERSTATES ECONOMIC BENEFIT ESTIMATES.

A. Another critical flaw in the survey methodology is the breakdown of ratepayers by size. When Duke Energy queried its ratepayer data to quantify the number of "large" C&I ratepayer counts against which to apply the DOE secondary research values per outage, it defined "large" as using 50 MWh or more. Duke Energy applied the highest avoided cost benefit estimate to these "large" customers. Yet in 2018, DEC's average residential ratepayer consumed 13.2 MWh per year.[64] Using such a low MWh threshold to categorize a C&I ratepayer as "large" results in higher ratepayer counts, to which overstated "value per outage" estimates are then applied, which in turn overstates the economic benefits Duke Energy will actually deliver to C&I ratepayers. To illustrate, Duke Energy multiplies each momentary

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[62] Ibid. Page 97.

[63] Phillips J, Wallace K, Kudo T, and Eto J. "Onsite and Electric Power Back-up Capabilities at Critical Facilities in the US." Primary research by the Argonne National Laboratory. April, 2016. Page 13.

[64] US Energy Information Administration. Customer count and sales data by rate class reported by DEC and DEP on Form 861.

(less than one minute) outage it claims to reduce for a "large" C&I ratepayer in 2019 by over $15,000. It is difficult to believe that a C&I ratepayer with usage roughly equivalent to four residential ratepayers can incur such a cost from a momentary outage, particularly when research indicates that 66% of US manufacturing facilities and 49% of retail stores employ on-site UPS systems.[65]

Q. DO YOU HAVE OTHER CONCERNS ABOUT THE MANNER IN WHICH DUKE ENERGY IS USING THE ECONOMIC IMPACT PER CI AND CMI TO ESTIMATE BENEFITS?

A. Yes. The surveys and secondary research the DOE completed were designed to estimate the economic impact *to each individual ratepayer* of service outages of various durations. It is inappropriate to aggregate the impact of individual C&I service outage impacts into a total C&I ratepayer impact estimate, without considering countervailing beneficial impacts to other C&I ratepayers, as this leads to exaggerated overall avoided cost benefit estimates. Consider several scenarios that are likely common in the event of a service outage:

- A residential customer, faced with no electricity for cooking and air conditioning, decides to go out to dinner, or to shopping mall, benefitting some businesses.
- A motorist in need of gasoline bypasses a gas station without power in favor of a gas station with power.
- A retail shop experiencing a momentary outage continues to ring up sales and process credit card transactions using the UPS systems attached to each register.
- A farmer who uses electric pumps to irrigate his or her fields simply elects to irrigate later in the day once power is restored, or to double irrigation the next day.

[65] Phillips J, Wallace K, Kudo T, and Eto J. "Onsite and Electric Power Back-up Capabilities at Critical Facilities in the US." Primary research by the Argonne National Laboratory. April, 2016. Page 13.

In each of these scenarios, the aggregation of individual C&I ratepayer impacts to estimate total C&I impacts leads to an exaggeration of overall costs incurred by C&I ratepayers. In the first scenario, the service outage results in an economic benefit for some C&I ratepayers. In the second scenario, the economic cost to one gas station represents an economic benefit to a second gas station. In the third scenario there is virtually zero economic C&I ratepayer cost (limited to ratepayers who approach the store during the 30-seconds in which the power is out, and decide not to shop), and in the fourth scenario there is zero C&I ratepayer economic cost. Yet the aggregation and application of the individual C&I impacts per CI or CMI consider none of the offsetting impacts of these scenarios.

Q. DO YOU HAVE ANY OTHER EVIDENCE TO BACK UP YOUR ASSERTION THAT THE APPROACH USED TO TRANSLATE RELIABILITY IMPROVEMENTS INTO ECONOMIC BENEFITS RESULTS IN OVERSTATED ECONOMIC BENEFITS?

A. Yes. Duke Energy claims that the benefits of its TUG program are driven largely by a reduction in momentary outages for C&I ratepayers located “upstream” of an outage in a backyard line. As Witness Stephens describes in his testimony, these momentary outages can be eliminated through other means at almost no cost. But for the sake of argument, let us assume that TUG is used to reduce momentary outages. In discovery, I asked for the industry classification codes of the C&I ratepayers associated with a specific undergrounding project to serve as an illustrative example. In this particular neighborhood there were only six “large” C&I ratepayers for which the project was projected to reduce momentary outages. With some additional research, I determined these six ratepayers to be:

- A large office complex with two 14-story towers;
- A smaller office building (three stories);
- A chain hotel;
- A restaurant;

- A commercial school (for example, a massage therapy or cosmetology school); and
- An unspecified retail establishment.

Note that none of these ratepayers are manufacturers, and only two are retail establishments. In the details provided in the TUG program cost-benefit analysis, it appears that upstream momentary outages for these facilities were 2.9 per year.[66] Assuming the "post undergrounding" performance will be DEC's 2019 average, or 1.0 (SAIFI),[67] the improvement due to undergrounding will result in slightly less than two fewer momentary outages per year, on average, for these six ratepayers. Recall that momentary outages are defined as less than a minute in duration. Consider also that UPS systems, which are sufficient to power through a momentary outage without incident, are available at 72% of stand-alone U.S. office buildings and 65% of U.S. hotels.[68] Yet Duke Energy's estimated annual value for momentary service interruption reductions for just these six C&I ratepayers amounted to $303,000 in 2025, growing to $561,000 in 2050, for a primary, present value benefit valuation of $3.6 million.[69] It is hard to imagine that these six C&I ratepayers would be willing to pay (i.e., to "value") pro-rata shares of $3.6 million to secure a reduction of 2 momentary outages per year. If these ratepayers don't already have them, UPS systems would be much less costly to install, not to mention more effective (as they reduce the momentary outages to zero, not to the Duke Energy average of one per year).

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[66] Oliver Exh. 7, workbook "TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx", tab "Area Data - Condensed", line "Annual Momentary Events Caused by Neighborhood Events (10 year average)."

[67] NCUC Docket No. E-100 Sub 138A. *DEC and DEP Quarterly Service Reliability Report (Q4, 2019)*. Jan 29, 2020. p. 1.

[68] Phillips J, Wallace K, Kudo T, and Eto J. "Onsite and Electric Power Back-up Capabilities at Critical Facilities in the US." Primary research by the Argonne National Laboratory. April, 2016. Page 13.

[69] Oliver Exh. 7 workbook TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx, tab "Mountainbrook", line 46 (Large CI ratepayer Momentary Interruption Cost avoided).

Q. DO YOU HAVE ANY QUANTITATIVE DATA TO BACK UP YOUR ASSERTION THAT THE AGGREGATION OF INDIVIDUAL SERVICE OUTAGE IMPACTS OVERSTATES THE OVERALL SERVICE OUTAGE IMPACT?

A. Yes. The US DOE has developed an online tool, the Interruption Cost Estimator, to estimate the value of improvements in service interruption duration SAIDI and service interruption frequency SAIFI. The tool uses the same (overstated) CI and CMI reduction valuations provided in the previously-cited LBNL secondary research that Duke Energy uses to translate reliability improvements into economic benefits in its program cost-benefit analyses. In discovery, I asked Duke Energy to estimate the system-wide SAIDI and SAIFI impacts of the GIP.[70] I input these SAIDI and SAIFI improvement estimates, along with the other data inputs listed below, into the Interruption Cost Estimator.

Table 4: DEC and DEP Inputs to the US DOE's Interruption Cost Estimator/Value of Reliability Improvements Tool

	Duke Energy Carolinas	Duke Energy Progress
State:	North Carolina	North Carolina
Non-Res Customer Count	285,618	208,383
Res Customer Count	1,719,715	1,203,508
Start Year:	2020	2020
Expected Asset Lifetime	30 years	30 years
Inflation rate	2.5%	2.5%
Discount Rate	6.8%	6.8%
SAIFI Before Improvement	1.09	1.35
SAIFI After Improvement	0.93	0.99
SAIDI Before Improvement	205	166
SAIDI After Improvement	177	111

The Interruption Cost Estimator indicated that the present value of the SAIDI and SAIFI improvements in DEC would be $1.957 billion, and the present value of the SAIDI and SAIFI improvements in DEP would be $2.835 billion. The combined benefit from the tool, $4.792 billion, is 40.9% less than the $8.106 billion in primary, present value benefits related to reliability Duke Energy projects from

[70] DEC response to DR 5-10 and DEP response to NCJC DR 2-7, attached as Alvarez Exhibit 14.

the GIP. In addition, recall that this lowered benefit estimate still suffers from the use of overstated economic values ($ per event) for C&I customers I described earlier.

Q. ARE THERE OTHER SYSTEMIC BENEFIT OVERSTATEMENTS OF WHICH THE COMMISSION SHOULD BE AWARE?

A. Yes. In several cost-benefit analyses, Duke Energy claims that spending on prospective replacement of an asset today results in a benefit to ratepayers. The rationale is that by spending $10 today, ratepayers can avoid spending $10 tomorrow, so the $10 that won't have to be spent tomorrow constitutes a benefit. In other words, Duke Energy is claiming that spending capital this year, and raising rates now, when it could have waited to spend that capital for five or ten years, is a ratepayer benefit. This makes no sense.

GIP programs in which future avoided costs are used to justify the advancement of capital spending without documented need to replace assets include TUG; transformer bank replacement; and oil breaker replacement. Duke Energy credits spending capital on these programs today with the avoidance of over $146 million in capital spent tomorrow.[71] The capital spending is not avoided, however; it is accelerated. Any claim of a "benefit" from spending capital earlier than necessary is sheer fantasy.

C. Dubious Secondary Economic Benefits from the GIP as Estimated by the IMPLAN model

Q. DO YOU HAVE OTHER INFORMATION WHICH INDICATES THAT DUKE ENERGY'S GIP BENEFITS ARE INFLATED BY BILLIONS OF DOLLARS?

A. Yes. The primary GIP benefit estimates I have critiqued so far suffer from a compounding effect. That is, reliability improvement estimates are *multiplied* by

[71] My analysis of multiple, program-specific cost-benefit analyses provided in Oliver Direct, Ex. 7. Attached as Alvarez Exhibit 10.

estimates of economic benefit per CI or CMI to estimate total economic benefits. During such multiplications, benefit overstatements are multiplied too. When somewhat overstated improvement estimates are multiplied by somewhat overstated economic benefits per unit of improvement, a dramatically overstated estimate of total economic benefit – the product of two overstated benefit estimates – results. For example, assume a reliability improvement estimate of 5 units is overstated by 20%, meaning that the actual reliability improvement was only 4 units. Assume that the economic benefit associated with each unit of reliability improvement, say $10, is also overstated by 20%, meaning that the actual economic benefit associated with each unit of reliability improvement is only $8. While a total benefit estimate using the overstated values would be $50 (5 units x $10/unit), the total benefit estimate using the actual values would be $32 (4 units x $8/unit). Here you can see the compounding problem, as two 20% overstatements, when multiplied, deliver a result which is overstated by more than 56% ($50 divided by $32).

Q. IS THIS THE TOTAL EXTENT OF THE COMPOUNDING PROBLEM IN DUKE ENERGY'S ESTIMATES OF GIP BENEFITS?

A. No. There is no question in my mind that Duke Energy's estimate of $9.2 billion in primary benefits, in present value terms, is dramatically overstated as a result of overstated reliability benefits, overstated estimates of the economic benefit per unit of reliability improvement, and the compounding effect. But Duke Energy then goes one step further. In an attempt to estimate the secondary benefits of its GIP to the North Carolina economy, DEC uses the dramatically overstated primary GIP ratepayer benefits as inputs into the IMPLAN software. Though the IMPLAN software suffers from other deficiencies, one deficiency is that it multiplies the dramatically overstated primary GIP benefits, which are themselves the product of compounded overstatements in reliability improvement and "value per avoided event" estimates, yet again.

Q. CAN YOU EXPLAIN THE DIFFERENCE BETWEEN PRIMARY AND SECONDARY BENEFITS OF THE GIP?

A. As explained by Duke Energy Witness Oliver, "Primary benefits consist of value that is directly captured by the Company and by customers."[72] He provides examples such as reductions in O&M spending by the Company and the costs ratepayers avoid when service interruptions are avoided, such as lost sales, lost product, and lost wages. He describes secondary benefits as "indirect value of the plan to third parties".[73] Though Witness Oliver does not say so directly, my understanding of the IMPLAN software leads me to think of these as "ripple effects" throughout the economy. For example, when a retail establishment loses a sale during an outage, the sales of companies that provide products and services to the establishment fall too. Or, when an employee is not sent home due to a power outage that a GIP investment avoided, that employee might spend the wages not lost on dining out, therefore benefitting a restaurant. Had the employee lost wages due to a service interruption, he or she might have economized, and cooked a meal at home instead.

Q. AREN'T THOSE LEGITIMATE BENEFITS OF RELIABILITY IMPROVEMENTS?

A. Yes, they are, and Duke Energy uses the IMPLAN software to estimate these secondary benefits. The IMPLAN software was developed to estimate the "ripple effects" throughout an economy from a specific economic activity. For example, IMPLAN can be used to estimate the secondary impacts of increases in hiring at a manufacturing plant, or the contributions of a particular industry, such as tourism or solar power, on a state's economy. However, as I mentioned before, Duke Energy uses dramatically overstated primary economic benefits from reliability improvements as inputs into IMPLAN. Obviously, dramatically overstated IMPLAN inputs lead to dramatically overstated IMPLAN secondary benefit outputs. As great as this deficiency is, however, Duke Energy's secondary benefit estimates suffer from a much greater failing. That is, in evaluating the costs and

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[72] Oliver Direct, Page 41 at 8.

[73] Ibid, Page 42 at 2.

benefits of its GIP, Duke Energy makes no attempt to estimate, let alone consider, the detrimental impacts on the North Carolina economy of the significant rate increases the GIP will generate.

Q. SO, DUKE ENERGY ESTIMATES THE SECONDARY BENEFITS OF RELIABILITY IMPROVEMENTS TO THE NORTH CAROLINA ECONOMY, BUT DOES NOT ESTIMATE THE DETRIMENTAL IMPACT OF HIGHER RATES TO THE NORTH CAROLINA ECONOMY?

A. That is correct. It is extremely misleading to incorporate secondary benefits in a cost-benefit analysis without also incorporating detrimental secondary impacts.

Q. WHAT ARE THE IMPACTS OF ELECTRIC RATE INCREASES ON THE NORTH CAROLINA ECONOMY?

A. The need for electricity is so universal and so ubiquitous that an increase in electric rates has an economic impact similar to a tax increase. In fact, one could conclude that electric rate increases have a greater impact than tax increases because taxes are more selective. (Only property owners pay property taxes, and only income earners pay income taxes, while almost all people and organizations, including renters, non-profit organizations, and government agencies, buy electricity.)

Electric rate increases manifest in multiple ways throughout a state's economy. Retailers must raise prices; governments may raise taxes or reduce services; businesses may look elsewhere for expansion; some business shift production to out-of-state or overseas facilities; and some businesses become more likely to close. It is certainly plausible, if not likely, that the negative impact of a 4.1% rate increase (5.3% not including fuel costs) offsets or even exceeds the secondary economic benefits Duke Energy estimates from its GIP. Based on the fact that Duke Energy's secondary benefits are based on dramatically overstated primary benefits (via inputs to the IMPLAN software), and due to the fact that the negative impact of electric rate increases likely exceed any secondary impacts of reliability benefits, I recommend the Commission disregard Duke Energy's secondary benefit estimates entirely.

Q. YOU HAVE TESTIFIED THAT DUKE ENERGY'S GIP UNDERSTATES RATEPAYER COSTS BY BILLIONS OF DOLLARS, AND OVERSTATES RATEPAYER BENEFITS BY BILLIONS OF DOLLARS. WHAT IS YOUR OVERALL CONCLUSION REGARDING THE BENEFITS AND COSTS OF DUKE ENERGY'S GIP?

A. Based on the detailed review of GIP programs, costs, and benefits Witness Stephens and I have conducted, I conclude that the GIP is *at best* a break-even proposition for Duke Energy ratepayers overall. In addition, given that 87% of projected GIP benefits stem from reliability improvements, and that 97% of these benefits are projected to accrue to C&I ratepayers,[74] I conclude that the GIP costs dramatically exceed GIP program benefits for residential ratepayers.

Q. DO YOU HAVE ANY ADDITIONAL SUPPORT FOR YOUR CONCLUSION THAT THE GIP COSTS DRAMATICALLY EXCEED GIP PROGRAM BENEFITS FOR RESIDENTIAL RATEPAYERS?

A. According to DEC, despite the paltry percentage of reliability improvements that will accrue to residential ratepayers, residential customers will likely be allocated about 48% of GIP costs.[75] Assuming, for the sake of argument, that Duke Energy's estimate of primary, present-value GIP benefits ($9.2 billion) are not overstated, I calculate that residential ratepayers will pay at least $7.85 for every $1 in benefits they receive:

Table 5: Calculation of residential ratepayer cost per dollar of residential GIP benefit

Economic benefits from reliability:	$8.106 billion
Residential ratepayer share of reliability benefits (2.6%):	$ 213 million

[74] My analysis of multiple, program-specific cost-benefit analyses provided in Oliver Direct, Ex. 7. Attached as Alvarez Exhibit 10.

[75] Pirro Direct, Ex. 7. "Residential Annualized Proposed Revenues" ($2.459 billion) divided by "Total Retail with Proposed Rate Increases" ($5.127 billion).

Present value of revenue requirements:	$3.485 billion
Residential ratepayer share of revenue requirement (48%)	$1.673 billion
Residential ratepayer cost per dollar of reliability benefits ($1.673 billion in costs divided by $213 million in benefits):	$7.85

Q. DOES THIS PROMPT ANY CONCERNS ABOUT INEQUITIES OF THE GIP AS PROPOSED?

A. Yes, and not just between residential and C&I ratepayers. If the GIP is approved as proposed, my revenue requirement estimate indicates Duke Energy shareholders will likely earn about $2.6 billion in return on equity over 30 years ($1.2 billion in present value terms). Yet if Duke Energy spends more on the GIP than promised (which, as indicated in my testimony on costs, is a number that has yet to be determined), ratepayers bear the risk. If Duke Energy delivers fewer benefits than projected, ratepayers bear the risk. The loose definition of costs ratepayers will have to pay, lack of Duke Energy accountability, and inequities in risk allocation all seem unjust and unreasonable to me. To address these GIP deficiencies, I believe one solution holds promise: the development of a transparent, stakeholder-engaged approach to distribution planning and capital budgeting process for future use in North Carolina.

VI. The Stakeholder Engagement DEC/DEP Conducted Was Superficial and Inadequate.

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony I will address the critical issues of transparency and stakeholder engagement in distribution planning and capital budgeting. I will begin with a quick review of the stakeholder engagement Duke Energy conducted in the development of its GIP, highlighting some deficiencies that have yet to be corrected. I will then present a step-by-step distribution planning and capital budgeting process that features true, transparent stakeholder engagement, and the development of stakeholder competencies over time. The purpose of this portion of my testimony is to compare the stakeholder engagement that has been conducted to date to the type of long-term, ongoing, holistic distribution planning and capital budgeting process that is possible, and which other jurisdictions are considering. Finally, I will describe the potential benefits that ratepayers could expect from the proposed process.

Q. WHAT IS YOUR IMPRESSION OF THE STAKEHOLDER ENGAGEMENT DUKE ENERGY CONDUCTED IN THE DEVELOPMENT OF THE GIP?

A. As I understand it, the stakeholder engagement process consisted of three phases, each marked by a workshop. The first phase/workshop consisted of Duke Energy's presentation of "Megatrends," and presented high-level information on the programs that would later be incorporated into the GIP. In phase two, Duke Energy presented its current GIP to stakeholders in a workshop. Although the GIP reflected changes based on stakeholders' critique of Power Forward, it was made clear that there would be no further changes to the GIP based on stakeholder feedback. In phase three, Duke Energy responded to stakeholder requests for more information through another workshop and some webinars focused on individual programs, costs, and benefit estimates. I perceive these efforts as Duke Energy's attempt to satisfy the Commission's request for more stakeholder engagement in grid modernization plan development as specified in the Commission's last rate case order.

Q. DO YOU BELIEVE THAT STAKEHOLDER ENGAGEMENT PROCESS WAS ADEQUATE?

A. As they say, "the proof is in the pudding." Judging by the GIP filed in this case, I must conclude that the stakeholder engagement effort did not result in a plan that delivers more value to ratepayers. Of the new programs presented in the GIP, two of the programs (energy storage and electric transportation) were initiated by the Commission, not Duke Energy. Of the remaining six new programs, Witness

Stephens's testimony categorizes four of them – transformer replacement, oil-filled breaker replacement, transmission system intelligence, and physical substation security, totaling over $500 million in proposed investment – in the "merits rejection" category. Duke Energy did not even bother to develop cost-benefit analyses for two programs, including distribution automation (expanded) and transmission system intelligence (new). A truly transparent distribution planning and capital budgeting process featuring genuine stakeholder-engagement would have avoided most, if not all, of these deficiencies before the plan was ever presented to the Commission.

Q. WHAT DO YOU BELIEVE DUKE ENERGY'S GIP STAKEHOLDER ENGAGEMENT PROCESS MISSED?

A. In the very first workshop, stakeholders "discussed the need for clear, concise metrics to prioritize grid modernization outcomes, measure the success of proposed programs, and determine the need for revisiting programs post-implementation." The GIP incorporates none of these items and does not hold Duke Energy accountable for GIP costs or benefits. Also in the first workshop, "Participants expressed a wide and diverging range of views on grid investment priorities."[76] It is unclear that these differences were resolved, and whether and to what extent stakeholder priorities were considered in development of the GIP. In the second workshop, stakeholders wanted to know "how much additional DER the grid could support with the plan's improvements."[77] Duke Energy's transmission upgrade program does not increase its grid's capability to accommodate DER by a single kilowatt, although DER accommodation is a critical concern of many stakeholders and ratepayer segments. Finally, despite the obvious stakeholder concern about how the multi-billion-dollar GIP would affect rates, Duke Energy provided no estimated rate impact to stakeholders,[78] and still has not done so. These are clear

[76] Oliver Direct, Exh. 11, page 5.

[77] Oliver Direct, Exh. 13, page 12.

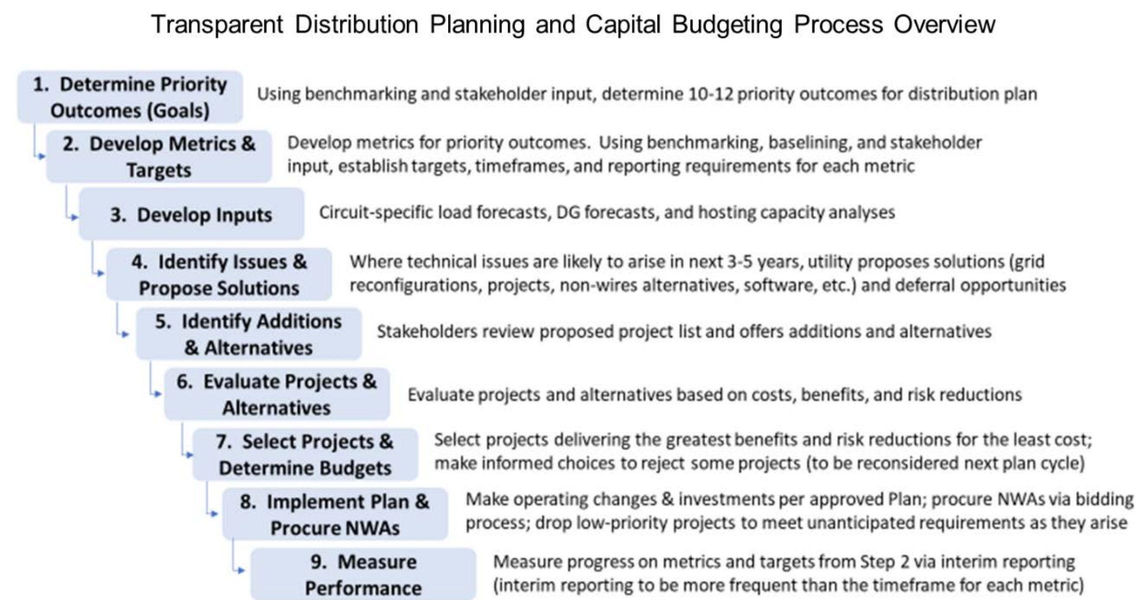
[78] DEC response to NCSEA DR 2-16, attached as Alvarez Exhibit 15.

and unequivocal indictments of the current distribution planning and capital budgeting process. I believe there is a much better way.

Q. WHAT KIND OF TRANSPARENT, STAKEHOLDER-ENGAGED DISTRIBUTION PLANNING AND CAPITAL BUDGETING PROCESS DO YOU HAVE IN MIND?

A. A full description of such a process at this point in my already lengthy testimony is not possible. However, Figure 3 provides an overview of the steps of a process the Commission might want to consider.

Figure 3: A transparent distribution planning and capital budgeting process for consideration



A process like this could be completed with stakeholder involvement every three to five years. The utility takes the lead on steps (3) develop inputs; (4) identify issues and propose solutions; (8) implement plan and procure non-wires alternatives; and (9) measure performance. All of these steps are familiar to utilities today, with the possible exception of circuit-specific DER forecasts and hosting capacity analyses. But these could easily be fit into utilities' existing distribution planning processes and are already commonplace among California and Hawaii utilities with high DER penetrations. All the other steps are intended to be led by Commission staff and stakeholders, with utility input. All differences are negotiated between stakeholders and the utility. Only issues that cannot be resolved would be brought to the Commission for a decision.

A distribution planning and capital budgeting process like this would resolve all the items missing from the GIP stakeholder engagement process. It incorporates goals, metrics, targets, and performance measurement. It holds the utility accountable for performance, and involves stakeholders early in evaluation of costs, benefits, and risk reductions of optional solutions to technical issues. It forces stakeholders to negotiate and agree upon priorities. It lets all stakeholders know the DER capacity available on various circuits, identifies constraints in advance, and provides mechanisms for resolving those constraints in the context of all other grid performance, safety, security and affordability priorities.

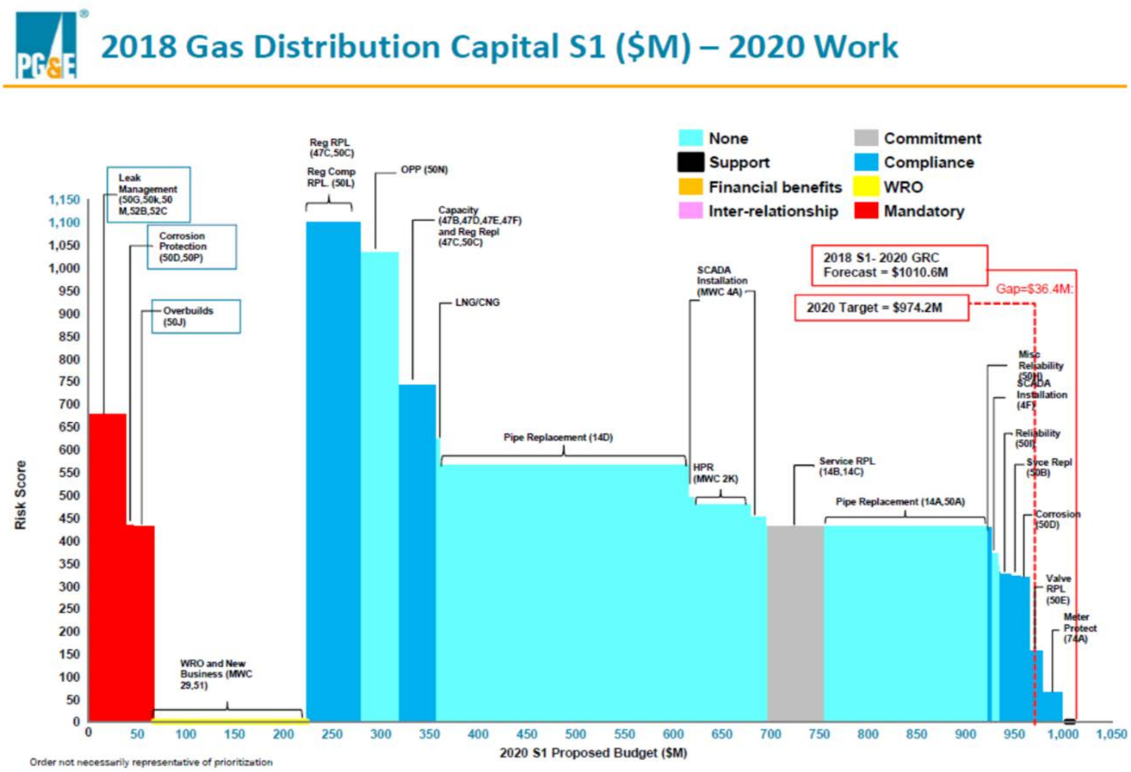
Q. STEP SEVEN APPEARS TO ALLOW STAKEHOLDERS AUTHORITY OVER DISTRIBUTION CAPITAL BUDGETS.

A. Yes, but with utility input, and the notion is not as far-fetched as you might believe. The safety portions of some distribution utility capital budgets are already determined in this manner. Figure 4 depicts the latest evolution of a risk-informed decision support process used by Pacific Gas and Electric's gas distribution planners following the highly publicized San Bruno pipeline explosion in 2010 that killed 8 residents.[79] Each block in the diagram represents a project, with the height of the block indicating the value (in this case, the amount of safety risk reduction) and the length of the block indicating capital cost. By organizing the projects in descending order of value and cost, stakeholders can quickly understand the trade-offs associated with various budget levels. Stakeholder questions the diagram can answer include, "If we establish a budget of $750 million, what value will we

[79] California PUC A.18.12.009. PG&E 2020 General Rate Case. Exhibit PGE-3, Gas Distribution Workpapers Supporting Chapters 2-2A. Page WP 2-10. December 13, 2018.

receive? What reduction in value is associated with a budget reduction to $500 million? What increase in value is associated with a budget increase to $900 million?"

Figure 4: PG&E's gas safety capital budget decision support analysis, 2018.[80]



Q. ARE OTHER JURISDICTIONS CONSIDERING DISTRIBUTION PLANNING AND CAPITAL BUDGETING PROCESSES LIKE THIS?

A. Yes. The California Public Utilities Commission has an ongoing docket[81] dedicated to distribution planning process improvement; several of the steps presented above are already a transparent part of distribution planning in that state. Commissions in

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[80] California PUC A.18-12-009. Pacific Gas & Electric General Rate Case. Exhibit PG&E-3 "Gas Distribution Workpapers Supporting Chapters 2-2a". Page WP 2-10. Dec. 12, 2018.

[81] California PUC. Rulemaking R.14-08-013. *Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.*

Michigan[82] and New Hampshire[83] are currently evaluating the process described above (in greater detail, of course) in investigational proceedings. These commissions are recognizing that the rhetorical questions I posed at the beginning of this testimony must be answered, and that investor-owned utilities cannot answer them on their own. These commissions are also recognizing: (1) that grid investment choices have long-term consequences; (2) that the capital amounts involved are enormous; (3) that a state economy's ability to accommodate rate increases is finite; and (4) that investor-owned utility incentives run counter to ratepayer and stakeholder incentives. All this means that grid investments must be very carefully considered and prioritized, and that stakeholder responsibilities in this regard will have to grow.

Q. HOW CAN STAKEHOLDERS GET THE EXPERIENCE THEY WILL NEED TO EFFECTIVELY PARTICIPATE IN A DISTRIBUTION PLANNING PROCESS?

A. Education is a process that happens over time. I am not suggesting that stakeholders are going to become grid engineers. Nor am I suggesting that stakeholders get involved in "business as usual" investment decisions or operations. What they need is the opportunity (and desire) to ask questions collegially, rather than in the context of a rate case; an appreciation for basic grid design, equipment, and operating concepts; and an understanding of pros and cons of various decisions and options they will be considering. I know first-hand that this is possible as a result of my working relationship with Witness Stephens over the past couple of years. While he has taught me much about grid design, equipment, and operations, one of the biggest things I've learned is that neither an electrical engineering degree or 35 years' grid planning and operations experiences is needed to understand the pros and cons of optional solutions to technical issues, or to make informed business

[82] Michigan PSC Docket U-20147. Five-Year Distribution Investment and Maintenance Plans.

[83] New Hampshire PUC Docket IR 15-296. Investigation into Grid Modernization.

decisions regarding distribution grids. The most important ingredients are historical operating data, unbiased technical advice, and a willingness to learn.

Q. WHAT DO YOU SEE AS THE ADVANTAGES OF A TRANSPARENT, STAKEHOLDER-ENGAGED DISTRIBUTION PLANNING AND CAPITAL BUDGETING PROCESS TO RATEPAYERS, THE COMMISSION, UTILITIES, AND STAKEHOLDERS?

A. Ratepayers in general, and state economies more broadly, are the clear focus of such a process. I believe ratepayers will benefit in three ways. First, rate increases will be held to a minimum. Second, ratepayers will secure greater benefits per dollar of rate increase. Third, the distribution grid will be able to accommodate the level of DER capacity ratepayers care to install, as well as the level of electrification they care to pursue, at a reasonable cost to all.

I also believe regulators would see benefits from such a process. Perhaps most importantly, I think the process would improve the state's economy by avoiding low-value rate increases that business and residential ratepayers would otherwise pay, an outcome of great interest to regulators and legislators. Although more difficult to quantify, I think the process would enable regulators to make more informed decisions by providing them with more objective and understandable information about the impacts and trade-offs of various grid investments. Last but perhaps most importantly, such a process would allow regulators to advance state policy objectives at the least possible cost to the North Carolina economy.

Though utilities will likely see the process as a challenge, there are some legitimate silver linings in the process for utilities to consider. Rate increases backed by a distribution plan developed through a transparent, stakeholder-engaged process will be subject to a lower risk of cost disallowances. Another benefit will be a change in the utility's role. Today, utilities make proposals that stakeholders critique. Each stakeholder pursues its own interests, putting utilities in the difficult position of opposing all stakeholders. Using the process, utilities will have an opportunity to become trusted partners and collaborators in a paradigm that respects their expertise and responsibility to assure safety and reliability, while seeking a reasonable return on investment for shareholders. Finally, when utilities are in sole control of distribution investment decisions in conditions of uncertainty, they run the very real risk, if not certainty, of making investments that will turn out to be mistaken with the benefit of hindsight. With stakeholder input, utilities are likely to make better decisions.

Finally, the process offers other stakeholders some of the same benefits recognized above for regulators. For instance, the process offers more transparency to stakeholders, and more objective and understandable information about the impacts and trade-offs of various grid investments. Over time, a stakeholder-engaged distribution planning process will produce stakeholders who are more educated and informed regarding technical distribution issues and distribution technologies, leading to more valuable regulatory processes. This has happened in integrated resource planning over the last few decades in some jurisdictions, and there is no reason the same outcome should not or could not be realized with regard to distribution planning in North Carolina.

VII. Summary and Recommendations

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A: My testimony began with historical evidence from US investor-owned utilities, which indicates that reliability has been deteriorating despite distribution grid investment growth far in excess of peak demand growth in recent years. I then presented evidence that Duke Energy understates the cost of the GIP to ratepayers by billions of dollars, and overstates the benefits of the GIP to ratepayers by billions of dollars. I concluded that the GIP is a break-even proposition *at best* for ratepayers overall, and dramatically negative for residential ratepayers. The GIP is justified almost entirely by reliability improvements for C&I customers, and I estimate residential ratepayers will pay almost $8 for every $1 in GIP benefits (both figures in present value terms). My testimony then compared the stakeholder engagement process Duke Energy conducted in the development of its GIP to a truly transparent and engaging distribution planning and capital budgeting process the Commission may wish to consider in the future.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on the GIP deficiencies and improvement opportunities presented, I recommend the Commission reject Duke Energy's GIP, and establish a separate proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process. This is consistent with Witness Stephens's primary recommendation. However, should the Commission reject my recommendation, I support Witness Stephens's secondary recommendations, which relate to individual GIP programs rather than complete GIP rejection. I also support all adjustments and conditions described in Witness Stephens's testimony for any GIP programs the Commission approves. Finally, I recommend the Commission reject deferred accounting cost recovery on the basis that it encourages suboptimal capital investment. This is also consistent with Witness Stephens's recommendations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time. However, I would like the opportunity to amend this testimony after seeing a demonstration of how Duke Energy used the Copperleaf C55 software to develop transmission hardening and restoration program benefit estimates.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Corrected Direct Testimony of Paul J. Alvarez on Behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and North Carolina Sustainable Energy Association either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 25th day of February, 2020.

s/ Gudrun Thompson
Gudrun Thompson

(Whereupon, the prefiled testimony of Dennis Stephens was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of: **Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina**	**) TESTIMONY OF DENNIS STEPHENS ON BEHALF OF THE NORTH CAROLINA JUSTICE CENTER, NORTH CAROLINA HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL AND SOUTHERN ALLIANCE FOR CLEAN ENERGY AND THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION**

Wired Group

PO Box 620756

Littleton, Colorado 80162

February 18, 2020

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EXHIBITS

Stephens Exhibit 1: Curriculum Vitae of Dennis Stephens.

Stephens Exhibit 2: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 5-4, Docket No. E-7, Sub 1214, January 27, 2020.

Stephens Exhibit 3: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al*., Data Request 4-6, Docket No. E-7, Sub 1214, January 21, 2020.

Stephens Exhibit 4: Duke Energy Carolinas Response to North Carolina Sustainable Energy Association, *et. al*., Data Request 3-32, Docket No. E-7, Sub 1214, January 2, 2020.

Stephens Exhibit 5: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al*., Data Request 5-33, Docket No. E-7, Sub 1214, January 27, 2020.

Stephens Exhibit 6: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al*., Data Request 8-34, Docket No. E-7, Sub 1214, February 10, 2020.

Stephens Exhibit 7: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al*., Data Request 5-40, Docket No. E-7, Sub 1214, January 27, 2020.

Stephens Exhibit 8: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al*., Data Request 2-4, Docket No. E-7, Sub 1214, January 9, 2020.

Stephens Exhibit 9: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al*., Data Request 2-19, Docket No. E-7, Sub 1214, November 25 2019.

I. Introduction

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is Dennis Stephens. My business address is 1153 Bergen Parkway, Ste. 130, Evergreen, Colorado, 80439.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am an independent consultant. I collaborate frequently with Paul Alvarez, who is also testifying in this docket, and his firm, the Wired Group, on behalf of clients in distribution utility regulatory proceedings on matters of electric distribution grid planning, investment, operations, reliability, and distributed energy resource accommodation.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A: After graduating from the University of Missouri with a bachelor's degree in Electrical Engineering, I began work for Xcel Energy (then Public Service Company of Colorado) as an electrical engineer in distribution operations. In a series of electrical engineering and management roles of increasing responsibility, I gained experience in distribution planning, operations, and asset management, and the innovative use of technology to assist with these functions. Positions I have held over the years have included Director, Electric and Gas Operations for the City and County of Denver Colorado; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments.

In 2007, I was asked to lead parts of Xcel Energy's SmartGridCity™ demonstration project in Boulder, Colorado, the first of its kind at the time, covering 46,000 ratepayers. I developed the technical foundations for the project, including the development of all concepts presented to the Xcel Energy Executive Committee for project approval, and including the negotiations with technology vendors on their contributions to the project. As Director of Utility Innovations for Xcel Energy, I also worked with many software providers, including ABB, IBM, and Siemens, helping them develop their distribution automation ideas into practical software applications of value to grid owner/operators. I retired from Xcel Energy in 2011, and now consult for the Wired Group part-time.

Q HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. No.

Q. HAVE YOU TESTIFIED BEFORE OTHER STATE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified jointly with Witness Alvarez in three rate cases before the California Public Utilities Commission. I testified regarding the appropriateness of multi-billion-dollar grid modernization proposals by Southern California Edison and Pacific Gas and Electric. I also critiqued Indianapolis Power and Light's $1.2 billion Grid Improvement Plan before the Indiana Utility Regulatory Commission and testified jointly with Witness Alvarez in cases regarding distribution grid planning process development in Michigan and New Hampshire. I have also supported the Wired Group in client projects not involving testimony, including one in South Carolina regarding Duke Energy's Grid Modernization

Plan,[1] and a similar paper on Dominion's Grid Transformation Plan.[2] (I note the Virginia SCC largely rejected Dominion's Grid Transformation Plan.)[3] My full CV is provided as Exhibit DS-1 to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on behalf of the North Carolina Justice Center, the North Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy (collectively, "NCJC et al.") and the North Carolina Sustainable Energy Association ("NCSEA"). My testimony critiques the Grid Improvement Plan ("GIP") and associated cost-benefit analyses Duke Energy Carolinas, LLC ("DEC") presents in this case.[4]

I. Preview and Recommendations

Q. PLEASE PROVIDE A PREVIEW OF YOUR TESTIMONY AND RECOMMENDATIONS IN THIS PROCEEDING.

A. My testimony begins with context, describing typical distribution planning processes utilities have employed for decades. I also provide historical data indicating that Duke Energy's reliability has deteriorated markedly in recent years despite grid investment growth far exceeding peak demand growth. My testimony then identifies multiple deficiencies in the design, technical

[1] Alvarez P and Stephens D. *Modernizing The Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers*. Paper prepared for GridLab. Jan. 31, 2019.
[2] Alvarez P and Stephens D. Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. October 5, 2018.
[3] Final Order RE: Petition of Virginia Electric and Power Company. Virginia State Corporation Commission Docket No. PUR-2018-00100 (January 17, 2019).
[4] DEC and Duke Energy Progress, LLC ("DEP") have each filed the GIP in their concurrent respective rate cases. Since the GIP is, for the most part, common to both DEP and DEC and incorporates territory-overlapping programs and proposed investments, I will be referring to DEC and DEP, collectively, as "Duke Energy" throughout my testimony in reference to the GIP proposal.

justification, and cost-effectiveness of many GIP programs, and identifies a complete lack of justification for others. These illustrate the opportunity for a transparent, stakeholder-engaged distribution planning and capital budgeting process to improve the value delivered to North Carolina ratepayers, communities, and the environment by distribution grid investments.

Q. WHAT IS YOUR PRIMARY RECOMMENDATION TO THE COMMISSION?

A. My primary recommendation is for the Commission to reject Duke Energy's GIP and establish a proceeding to develop such a process for use in developing future distribution plans and capital budgets that better align the needs of stakeholders and utilities. Witness Alvarez's testimony provides an outline for such a process, and additional justification for the same recommendation.

Q. IN THE EVENT THAT THE COMMISSION DOES NOT ACCEPT YOUR PRIMARY RECOMMENDATION, DO YOU HAVE A SECONDARY RECOMMENDATION?

A. Yes. My testimony provides a secondary, alternative recommendation, wherein the Commission evaluates each GIP program independently. This part of my testimony examines individual GIP programs and sub-components in detail, providing valuable, objective information regarding the design and justification (or lack thereof) for each GIP program. I categorize GIP programs into groups of similar merit. In the event the Commission rejects my primary recommendation, I hope these "merit groupings" will serve as a set of secondary recommendations to inform Commission decisions. The merit groups and programs are presented in Table 1, summarized below, and explained in detail in my testimony.

Table 1: Summary of GIP Programs/Sub-components By Merit

Program/Subcomponent	Capital $ per Oliver Exh. 10 (in millions)	Suggested Adjustments	Capital $ per NCJC/NCSEA If GIP Not Rejected
Merits Approval w/Conditions	$ 374.16	$ -	$ 374.16
Integrated Volt/VAr Control	$ 216.66	$ -	$ 216.66
Transmission H&R -- Flood & Animal Mitigation Components	$ 13.18	$ -	$ 13.18
Long Duration Interruption/High Impact Sites	$ 27.10	$ -	$ 27.10
Enterprise Applications/ISOP Software/DER Software	$ 41.94	$ -	$ 41.94
Cyber and Physical Security, excluding substation physical	$ 23.04	$ -	$ 23.04
Enterprise Comm's excluding new data and voice networks	$ 52.24	$ -	$ 52.24
Merits Approval w/Material Modifications & Conditions	$ 843.05	$ (336.80)	$ 506.25
Self-Optimizing Grid/Advanced Dist Mgmt System	$ 722.48	$ (336.80)	$ 385.67
Transmission H&R (DER Capacity Upgrades ONLY)	$ 120.57	$ -	$ 120.57
Merits Rejection	$ 659.95	$ (659.95)	$ -
Targeted Undergrounding	$ 114.54	$ (114.54)	$ -
Distribution Transformer Retrofit	$ 118.02	$ (118.02)	$ -
Transfomer Bank Replacement	$ 116.39	$ (116.39)	$ -
Oil-Filled Breaker Replacement	$ 200.29	$ (200.29)	$ -
Substation Perimeter Security	$ 110.71	$ (110.71)	$ -
Merits Rejection Pending Further Evaluation	$ 440.27	$ (440.27)	$ -
Enterprise Comm's, new data & voice (tech/econ make/buy analyses)	$ 159.58	$ (159.58)	$ -
Distribution Automation (benefit-cost analysis)	$ 194.29	$ (194.29)	$ -
Transmission System Intelligence (benefit-cost analysis)	$ 86.41	$ (86.41)	$ -
GIP Components Being Considered in Other Dockets	$ 192.48	$ (192.48)	$ -
Energy Storage (NCUC #E-100, Sub 164)	$ 129.00	$ (129.00)	$ -
Electric Transportation (NCUC #E-2 Sub 1197 & E-7 Sub 1195)	$ 63.48	$ (63.48)	$ -
TOTALS	$ 2,509.92	$ (1,629.51)	$ 880.41

Programs and sub-components that merit approval with conditions. Some GIP programs merit approval with conditions. The mix of spending between and even within the programs and sub-components would likely be optimized through the use of a transparent, stakeholder-engaged distribution planning and capital budgeting process. Programs that I believe merit approval with conditions, amounting to $374 million in capital, include (1) the Integrated Volt-VAR

Control ("IVVC") program; (2) the flood and animal mitigation components of the Transmission Hardening and Restoration program; (3) the Long Duration Interruption/High Impact Sites program; (4) foundational software, including Enterprise Applications, Integrated System Operations Planning ("ISOP"), and Distributed Energy Resource ("DER") dispatch; (5) Cybersecurity (excluding substation physical security); and (6) Enterprise Communications (excluding mission critical voice and data network investments pending further evaluation, as described).

Self-Optimizing Grid. This program merits approval with conditions, but at a reduced investment level (from $722 million to $385 million) so as to focus the spending on the 50% of circuits and segments of highest priority/greatest benefit. This will improve the benefit-to-cost ratio of self-optimizing grid program capital and reduce the risk that the program is applied to circuits for which costs exceed benefits. Reliability performance can be measured so that informed consideration can be given to program expansion in the future. If the Commission approves this program, I also recommend it keep a very close eye on the $48 million advanced distribution management system deployment.

Transmission Hardening and Resilience (not related to flood or animal mitigation). My testimony explains why this capital budget ($120 million) merits approval with conditions but modifies the goal and design of the program completely. As proposed, the program makes progress towards greater accommodation of DER, but does not actually increase the capacity of Duke Energy's grid to accommodate more DER by a single watt. Instead, I recommend this entire budget be focused on a smaller number of projects designed to increase the capacity of Duke Energy's grid to accommodate more DER. These include (1) upgrading 44kV lines to 100kV lines; and/or (2) increasing the number of substations served by 44kV lines. The value of involving stakeholders in the identification of 44kV lines and substations to maximize DER accommodation benefit per dollar of capital is clear.

Programs to Reject Due to Lack of Cost-Effectiveness/Compliance with Standard Practice. My testimony explains why these programs are not cost effective and are not standard practice in the industry. Totaling $660 million, they include (1) targeted undergrounding; (2) distribution transformer retrofit; (3) transformer bank replacement; (4) oil-filled breaker replacement; and (5) physical substation security.

Programs to Reject Pending Further Evaluation. My testimony explains that insufficient information is available to make a recommendation on these programs. Witness Alvarez's testimony explains why a technical and economic make vs. buy analysis, considering recent and emerging public telecom network capabilities, is required before a recommendation regarding $160 million in new voice and data communications network investments can be determined. I also note that no benefit-cost analysis has been completed on distribution automation and transmission system intelligence programs and recommend that the Commission reject them until Duke Energy completes these analyses.

Q. PLEASE DESCRIBE THE CONDITIONS ON APPROVAL THAT YOU RECOMMEND.

A. I recommend the Commission apply three conditions for any GIP programs it approves. The first condition is ongoing performance measurement against pre-GIP baselines. I point specifically to measuring annual average voltage reductions from the IVVC program, as well as SAIDI and SAIFI improvements from the Self-Optimizing Grid program, but I believe a policy of performance measurement is important for any extraordinary distribution investments the Commission approves. There is no other way to determine if the program benefit claims Duke Energy makes are reasonable, or if the approved programs should be expanded or curtailed in the future.

The second of these conditions involve cost caps and associated operating audits. As indicated in Witness Alvarez's testimony, Duke Energy never actually provides a GIP capital budget limit or estimate of the cost to ratepayers. I recommend the Commission establish capital cost caps for every GIP program or sub-component it approves, as well as specifications for the program-specific extents of capabilities it expects to be operational within the cost cap (generally, as specified by Duke Energy in its GIP program descriptions and/or cost-benefit analyses). Without cost caps or extent specifications (circuits, line miles, substations, etc.), the Commission has no way of knowing whether promised capabilities or extents are operating for the proposed costs. Program audits will be needed to verify that capabilities have been implemented to the extent promised for the costs estimated. The Commission may also wish to act on my recommendation regarding financial consequences for exceeding program cost caps or failing to deliver the promised extent of a program's capability within a cost cap. As proposed, ratepayers bear all of these risks, and shareholders none of these risks. Cost sharing between ratepayers and shareholders for cost overruns or extent shortfalls would hold Duke Energy accountable for cost estimate accuracy and program implementation success.

The third condition relates to capital Duke Energy spent on GIP assets placed into service during the test year. For the GIP programs the Commission approves, I recommend capital spent on GIP assets placed into service during the test year be included in program cost caps as a condition of approval. For the GIP programs the Commission rejects – and in particular, those programs it rejects due to a lack of cost-effectiveness and industry standard practice compliance – I recommend recovery of and on capital spent on such assets placed into service during the test year be denied.

Q. DO YOU HAVE OTHER RECOMMENDATIONS FOR THE COMMISSION REGARDING THE GIP?

A. Yes. My testimony indicates that many GIP programs are not cost-effective, and outside standard industry practice, and that Duke Energy provides no economic justification at all for other GIP programs. Witness Alvarez's testimony indicates that GIP program costs to ratepayers and communities are dramatically understated and ratepayer benefits dramatically overstated. In this rate case Duke Energy proposes deferral accounting treatment to address "regulatory lag" for GIP costs. This serves to increase the likelihood that Duke Energy will earn or exceed its authorized rate of return on equity, thereby increasing Duke Energy's already-adequate incentive to invest in its grid. I concur with Witness Alvarez's conclusion that deferral accounting treatment leads to excessive capital spending on sub-optimal projects, and with his recommendation that deferral accounting for GIP investments be rejected on that basis.

II. Historical Context

Q. BEFORE PROCEEDING, PLEASE PROVIDE THE HISTORICAL CONTEXT YOU MENTIONED.

A. Since the introduction of alternating current and the power grid concept in the early 20th century, utilities have taken a simple approach to grid planning. They build systems to deliver power from an energy source to a consumer. As the number, locations, and energy use of the consumers grew, utilities methodically planned and implemented expansions in grids' geographic extents and energy capacities over time. As grids developed, grid reliability and safety issues arose. A solution was devised, which was the use of substations as hubs for protection and control to deliver safe and reliable electricity to consumers via "spokes," which engineers know as circuits. Early grids were initially protected by fuses, which later evolved into oil-filled circuit breakers in conjunction with analog electromechanical relays, reclosers, and various devices to reduce circuits into individualized sections. These protection systems were designed to de-energize small sections of the grid, isolating faults and other problems to prevent damage to the rest of the grid, and became the standard for grid protection and control.

Q. HOW IS THIS HISTORICAL CONTEXT RELEVANT TO THIS PROCEEDING?

A. For over a century, utilities have successfully incorporated new technologies, along with new operating practices, to deliver safe, reliable, and low-cost electric distribution services under conditions of growing loads and increasing ratepayer expectations. Utilities have done so using a methodical, common-sense approach to distribution planning that focuses on a single question: do the benefits (i.e., reduction in risk of an adverse event such as a service interruption) justify the costs? Over the course of many decades, a generally-accepted distribution planning process, as well as a generally-accepted set of standard industry practices, has arisen. Both the planning process and the standard practices are the result of thousands of electrical engineers like me, asking this question thousands of times while working on thousands of distribution circuits.

Q. ARE YOU SUGGESTING THAT THERE IS NO NEED FOR INNOVATION IN DISTRIBUTION PLANNING AND INVESTMENT?

A. Not at all. While generally-accepted distribution planning processes and standard practices have proven their value and should not be abandoned, this does not mean they have not undergone, or should not undergo, adjustments from time to time. Duke Energy Witness Oliver identifies megatrends prompting the development of the GIP.[5] I condense these down into two that require at least some adaptation of utilities' historical distribution planning processes: (1) the increasing penetration of distributed energy resources ("DER"), which can lead to bi-directional power flow in high-enough capacities (towards the substation as well as away from it); and (2) increased frequency of severe weather events.

[5] *Direct Testimony of Jay W. Oliver*, ("*Oliver Direct*"), Exhibit 2, p. 2 (September 30, 2019).

However, I do not agree that these trends require a departure from best utility practices in distribution planning. Changes in DER adoption and weather severity simply require the application of new technology and practices on an as-needed basis, justified through the technical reviews and cost-risk evaluations that have always been a part of utility distribution planning processes. Stakeholders can and should be part of these reviews, evaluations, and decisions. I also do not agree that large investments in grid modernization require a change in the methods by which utilities are compensated.

Q. WHAT RELEVANCE DO YOUR CONTEXTUAL OBSERVATIONS HAVE TO DUKE ENERGY'S GIP?

A. Duke Energy's GIP exhibits characteristics common to such plans issued by US investor-owned utilities in recent years: (1) it was not developed according to best practices in distribution planning; (2) it recommends investment dramatically above and beyond "business as usual" investments; (3) it requests extraordinary ratemaking treatment, which would provide additional incentive to invest; and (4) it is justified by cost-benefit calculations based on irregularities and weak assumptions, as described in Witness Alvarez's testimony. I believe these characteristics render the GIP fundamentally flawed, and that the GIP would not meet North Carolina's need for low-cost, safe, reliable, and increasingly clean electricity.

The North Carolina economy and ratepayers can only bear so much rate increase. As a result, grid investments must be very carefully considered and prioritized. Failure to do so presents its own kinds of risks to the North Carolina economy. It also presents risks to the achievement of North Carolina's Clean Energy Plan,[6] as rate increases wasted on cost-ineffective investments are no longer available to fund grid capabilities offering better "bang for the buck." My testimony is intended to provide a basic technical evaluation of GIP programs and sub-components to help the Commission make informed choices regarding Duke Energy's GIP.

Q. PLEASE PROVIDE EVIDENCE TO SUPPORT YOUR ASSERTION THAT RELIABILITY OF DUKE ENERGY'S NORTH CAROLINA GRID HAS DETERIORATED SIGNIFICANTLY IN RECENT YEARS DESPITE DRAMATIC INCREASES IN GRID INVESTMENT.

A. I completed the same reliability vs. investment analyses for DEC (Figure 1) and DEP (Figure 2) that Witness Alvarez completed on a national basis, which is contained in his testimony that is being filed in this docket concurrently.[7] While growth in peak demand does justify much of DEC's and DEP's grid investment increases, DEC and DEP's respective grid investment increases exceed peak demand growth by 37% and 61%[8]. One would hope these excess investments would lead to at least some reliability improvements. Yet, as is the case nationally, DEC and DEP's performance under key indices of reliability, SAIDI and SAIFI, have deteriorated significantly despite grid investment in excess of capacity needs. (Note that for SAIDI and SAIFI, lower values represent better performance.)

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[6] Report by the North Carolina Department of Environmental Quality. October, 2019. Available here: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf

[7] Sources: FERC Form 1 and EIA Form 861 data, 2013 through 2018.

Figure 1: Relationship between Grid Investment and Reliability for DEC

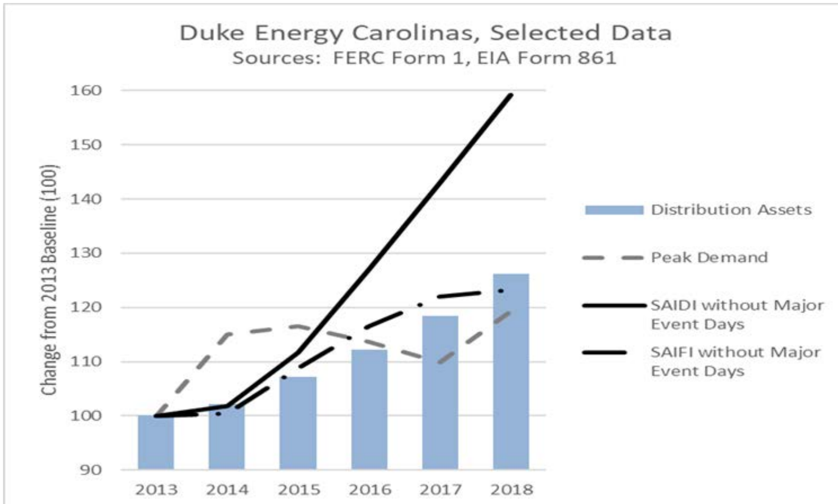
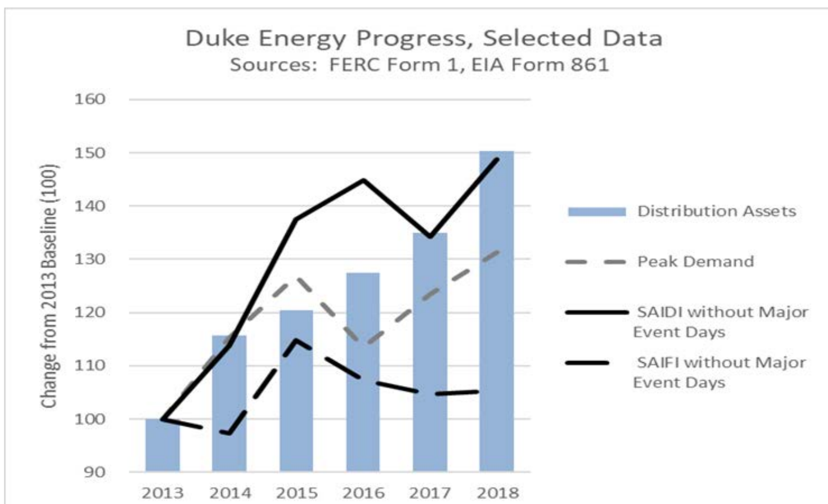


Figure 2: Relationship between Grid Investment and Reliability for DEP[9]



As shown in Figure 1, DEC's SAIDI and SAIFI performance have deteriorated almost 60% and more than 20%, respectively, since 2013 despite grid investment growth 37% greater than peak demand growth. As shown in Figure 2, DEP's SAIDI and SAIFI performance have deteriorated almost 50% and more

[9] As referenced above, DEC and DEP are each presenting the GIP program for approval in their respective concurrent rate cases. To that end, I have included DEC *and* DEP analysis here as it supports my point that historical investments to not correlate with SAIDI and SAIFI improvements. I believe this is a key indictment of the GIP.

than 5%, respectively, since 2013 despite grid investment growth 61% greater than peak demand growth.

Q. WHAT DO YOU CONCLUDE FROM THIS DATA?

A. I do not conclude from this data that investments in reliability or weather event resilience are bad ideas. Instead, I conclude from this data that the grid investments that DEC and DEP been making in recent years do not appear to be achieving the intended results. In light of this, Duke's proposed investments in the grid to improve reliability, enhance resilience, or facilitate deployment of DERs must be very carefully considered and prioritized.

III. GIP Programs Meriting Approval with Conditions

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. Should the Commission disagree with my primary recommendation to deny the request for approval of the GIP and institute a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process, then, in the alternative, some of the GIP programs may be approved with conditions. In this section of my testimony, I will discuss the GIP programs and sub-components that I believe, under my secondary recommendation, may merit approval with conditions. I will describe my rationale for these programs' merits, as well as conditions I believe the Commission should require in the event it approves spending for these programs and sub-components. I will conclude this section with a discussion regarding the potential value of a transparent, stakeholder-engaged distribution planning and capital budgeting process, as I believe such a process could improve the GIP even among meritorious programs. The GIP programs and sub-programs that I believe may merit approval with conditions include:

- Integrated Volt-VAR Control (“IVVC”);
- Flood and Animal Mitigation portions of Transmission Hardening and Resilience;
- Long Duration Interruption/High Impact Sites;
- Enterprise Applications, ISOP software, and DER dispatch software;
- Cyber security portions of Physical and Cyber Security; and
- Power electronics for Volt-VAR Control.

Q. WHY DO YOU BELIEVE THESE GIP PROGRAMS MAY MERIT APPROVAL WITH CONDITIONS?

A. All of the GIP programs on this list satisfy one or more of the following criteria:

- They represent standard industry practice;
- They consist of software needed to optimize grid assets or operations, or to improve cyber security;
- They are likely, with conditions, to deliver benefits to ratepayers in excess of costs to ratepayers without material modifications of the program as proposed;
- They are critical to stakeholders' value that cannot be otherwise secured.

Q. WHAT CONDITIONS DO YOU RECOMMEND THE COMMISSION ATTACH TO APPROVAL OF THESE PROGRAMS?

A. The Commission should consider attaching a common set of conditions to any and every GIP program it might approve. These conditions include cost controls, operating audits, and performance measurement.

Q. PLEASE DESCRIBE THE COST CONTROL CONDITIONS.

A. As described in Witness Alvarez's testimony, there are significant differences between the program capital amounts provided in the GIP[10] and the program capital amounts provided in the benefit-cost analyses. I also note the equivocal response to a clear request during discovery about the amount of capital being requested for the GIP, to which Duke Energy responded it is only requesting, though I am paraphrasing: (1) a return on and of capital spent on GIP assets placed in service as of the closing date of this rate case; and (2) deferred accounting treatment for GIP assets placed in service between this rate case and the next rate case.[11] I find this level of ambiguity concerning, and believe the Commission should share my concern. I do not believe ratepayers will be best served if Duke Energy treats GIP capital as a pot of money it can invest as it wishes.

Instead, any GIP program the Commission approves should include a clearly defined functional scope, a clearly defined geographic scope, and capital budget sufficient to secure the functionality for the defined geography. This is consistent with the accountability issue Witness Alvarez raises in his testimony, but on the cost side of the benefit-cost equation. Furthermore, I am concerned

[10] Oliver Direct, Exhibit 10, page 3.
[11] DEC response to NCJC et al. Data Request No. (hereinafter, "DR") 5-4(a), attached as Stephens Exhibit 2.

that ratepayers will bear 100% of the risk of any cost overruns or scope shortcomings. I encourage the Commission to consider cost caps for specific programs and scopes, complete with ratepayer protections (such as 50/50 cost sharing between ratepayers and shareholders for cost overruns). Finally, program cost caps should incorporate all capital for each program, including capital spent prior to the end of the test year in this rate case.

Q. PLEASE DESCRIBE THE OPERATING AUDITS.

A. This condition is closely tied to cost caps. In my experience, an investor-owned utility at risk for exceeding a cost cap with consequences will simply reduce functionality or geographic scope in order to remain under the cap/avoid the consequences. This is not the intended outcome of the cost caps condition. As a result, I also recommend operating audits, with appropriate use of random sampling, to validate the functionality and geographic scope of any and all approved GIP programs. For example, if the GIP proposes that Duke Energy will add IVVC to 1800 circuits for $200 million by 2024, an operating audit conducted in 2025 should validate that IVVC software is providing instructions to IVVC equipment installed on 1800 circuits.

Q. PLEASE DESCRIBE PERFORMANCE MEASUREMENT CONDITIONS.

A. Performance measurement should be a condition of every program for which performance is likely to be variable. Baseline performance levels should be measured before capabilities are added, and post-deployment performance should be measured on an ongoing basis. Performance measurement is critical for ensuring that ratepayer benefits are being maximized, and increased over time, but also to inform potential future expansions or curtailments of GIP programs.

In this group of meritorious programs, IVVC stands out as a program requiring performance measurement. Duke Energy should be required to report baseline and annual average voltage for every circuit with IVVC capabilities. Ameren Illinois' IVVC measurement and validation program is an excellent example of sound IVVC performance measurement.[12]

Q. BEFORE PROCEEDING, PLEASE COMMENT ON THE RESTRICTIONS THAT DUKE ENERGY IS PLACING ON DER INSTALLATIONS DUE TO VOLTAGE CONCERNS.

A. In its Method of Service Guidelines, Duke Energy describes limitations it is placing on DER locations due to operational voltage issues. The rationale for these limitations -- challenges associated with non-standard line voltage regulator ("LVR") settings – are not valid from a technical perspective. I can understand why grid operators would want to minimize the reconfiguration flexibility reductions associated with non-standard LVR settings. But new loads routinely serve to reduce reconfiguration flexibility; it is part of grid operators' job to manage around reconfiguration flexibility reductions, and they do so successfully all the time. Regarding backfeed, it is easy to manage as long as DER relative to load is not extremely high. When DER relative to load does get high, technologies are available to manage backfeed. Nor are voltage issues generally, or the presence of IVVC capabilities specifically, a reason to restrict DER on a

[12] Illinois Commerce Commission 18-0211. *Ameren Illinois Voltage Optimization Plan*. Jan 25, 2018. P. 27-30.

circuit. Capacitor banks, smart inverters, and IVVC software setting adjustments can all be employed to cope with volt-VAR issues related to DER.

To summarize, neither stakeholders nor the Commission should accept Duke Energy's limitations on DER without a technical challenge. The fact that a DER installation might make a grid operator's job more difficult is not an acceptable restriction rationale, and the software Duke Energy is installing, and which I have categorized as "merits approval with conditions" in this testimony, will help grid operators manage DER capacity growth. The unwarranted restriction of DER locations appears to me to be yet another reason to implement a transparent, stakeholder-engaged distribution planning and capital budgeting process in North Carolina.

Q. WHAT KIND OF VALUE COULD A TRANSPARENT, STAKEHOLDER-ENGAGED DISTRIBUTION PLANNING AND CAPITAL BUDGETING PROCESS DELIVER REGARDING THE MERITORIOUS PROGRAMS YOU DESCRIBE IN THIS SECTION?

A. Witness Alvarez's testimony describes a transparent, stakeholder-engaged distribution planning and capital budgeting process that warrants Commission consideration. While some will perceive such a process as an attempt to limit grid investment, I prefer to think of it as a way to optimize grid investment. For example, while I believe the GIP programs listed in this section may merit approval, I pass no judgement regarding the relative size or mix of the investments. Should the GIP devote more capital to the IVVC program and less on cybersecurity? Maybe; it depends on priorities, perceptions of threats, degree of program effectiveness, risk tolerance, and a host of other variables that exist to varying degrees within various ratepayers and stakeholders. When a utility makes these decisions for us, it can only fight stakeholders, as any decision the utility makes will put it on the wrong side of some stakeholders' interests. When a utility works with stakeholders as a trusted advisor, explaining the pros and cons of various approaches to an emerging issue or opportunity, it is able to better align goals, interests, and priorities and make the right investment choices.

IV. GIP Programs Requiring Material Modifications and Conditions to Merit Approval

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I will discuss the GIP programs that must be materially modified in order to merit Commission approval under my secondary recommendation, including the Self-Optimizing Grid ("SOG") and Transmission Hardening and Resilience Programs. I will recommend that the SOG budget, should the Commission approve the program, be reduced to better focus capital on high-priority circuits and sections. I will recommend that the Transmission Hardening and Resilience programs be dedicated solely to actual capacity increases designed to accommodate more DER before they can merit approval. Otherwise, I recommend the Commission reject this spending entirely. I will also identify opportunities for a transparent, stakeholder-engaged distribution planning and capital budgeting process to deliver value when considering capital outlays for these types of programs.

A. Self-Optimizing Grid

Q. WHAT MATERIAL MODIFICATIONS DO YOU RECOMMEND FOR DUKE ENERGY'S SOG PROGRAM?

A. The notion of "networking" circuits or substations so that a source of back-up power is available in the event the primary source fails is nothing new. Utilities, including DEC and DEP, have been sectionalizing circuits and building back-up supply lines (called tie lines) for decades. Duke Energy's SOG program simply does more of this networking, allows it to be executed remotely (without sending linemen in trucks to throw switches), and with less preparatory analysis (through software) to ensure a grid reconfiguration doesn't create more problems than it solves. However, like all investments intended to improve reliability, the law of diminishing returns applies. That is, every incremental capital dollar spent delivers less incremental reliability improvement than the capital dollar just spent. As mentioned by Witness Alvarez in his testimony, there is a balance to be struck between reliability and affordability. Taken to an extreme, our grid could be made perfectly reliable, though few would be able to afford electricity. As it relates to the SOG program, the questions are (1) to what extent/which circuits to apply it; and (2) into how many sections should each circuit be split?

Q. HOW DOES ONE DETERMINE THE NUMBER OF/SELECT CIRCUITS TO WHICH TO APPLY THE NETWORKING CONCEPT?

A. It is part art and part science, and is yet another example of why a transparent, stakeholder-engaged approach to distribution planning and capital budgeting creates value for ratepayers. All else being equal, circuits with greater numbers of ratepayers will receive greater benefits from networking than circuits with fewer numbers of ratepayers. But not all ratepayers are created equal. As the long duration interruption/high impact sites program recognizes, reliability is more critical to some facilities/districts (hospitals, airports, downtowns) than others. What I can tell you for certain is that the benefit-to-cost ratio improves as the focus of networking spending tightens. The concept is best illustrated by example. Consider six circuits, each of which has the same cost for networking, and a variety of projected benefits:

Circuit Number	Networking Cost	Projected Benefit
1	$2	$3.00
2	$2	$2.75
3	$2	$2.50
4	$2	$2.25
5	$2	$2.10
6	$2	$2.05
Totals	$12	$14.65

Assume that cost estimates are solid, but that benefit estimates are less so. As Witness Alvarez's testimony indicates, benefit estimates are generally subject to a significant number of assumptions that cannot be assured. While the networking program in the hypothetical example indicates a benefit-to-cost ratio of 1.2 to 1 ($14.65/$12), the benefit cost ratio could be improved to 1.65 to 1 ($8.25/$5) by limiting the investment to the first three circuits. Note that a benefit variance of as little as 10% makes circuits 5 and 6 cost-ineffective, and a benefit variance of as little as 15% also makes circuit 4 cost-ineffective. So, reducing the number of circuits not only improves the benefit-to-cost ratio, it reduces the risk that the treatment (in this case SOG) will cost more than the benefits delivered, particularly considering the variability surrounding benefit estimates.

Q. HOW DOES ONE DETERMINE THE NUMBER OF SEGMENTS INTO WHICH A CIRCUIT SHOULD BE DIVIDED?

A. The law of diminishing returns applies here too. Consider a circuit with 1,000 ratepayers. Splitting this circuit up into two segments will enable 500 ratepayers to receive power from a back-up source when the primary source fails, a 50% improvement. Now consider splitting this circuit into three circuits, which would enable 667 ratepayers to receive power from a back-up source when the primary source fails. While a 66% improvement is better than a 50% improvement, note that the incremental improvement of three sections over two is only 16%, while the incremental improvement of two sections over one is 50%. Each additional section – four, five, or six – will each deliver less and less incremental benefit. Such is the law of diminishing returns, and the concept is useful to consider not just within a program, but between programs, and even for an overall distribution rate base. It is yet another example of why distribution planning and capital budgets must be carefully considered and prioritized, ideally with the input of educated and informed stakeholders.

Q. HOW DO THESE OBSERVATIONS INFORM YOUR RECOMMENDATION FOR MATERIAL MODIFICATIONS TO DUKE ENERGY'S SOG PROGRAM?

A. My recommendation is that the fixed costs of the SOG proposal, including the Advanced Distribution Management System ("ADMS") and proof-of-concept ($48.9 million) be approved, while the variable portion – the extent to which SOG is deployed geographically – be cut in half (from $673.6 million to $336.8 million). While I have significant concerns about ADMS, which I will discuss, I believe this solution will increase the benefit-to-cost ratio of the SOG program, and reduce the risk that SOG capital will be applied to circuits that will not deliver benefits in excess of cost. As indicated in Witness Alvarez's testimony, the reliability of Duke Energy's benefit estimates is questionable, meaning that variability in benefit delivery is likely to be high. Stakeholder engagement could be used to establish criteria for circuit prioritization.

Another reason to cut the SOG capital budget is the high degree of variation in capital cost estimates. In discovery, Duke Energy admitted that SOG cost estimates were prepared at an AACE Class 4 level of detail.[13] Class 4 cost estimates are only accurate to within minus 30%/plus50%, so better to approve a smaller budget until better cost estimates can be developed for specific circuits. Finally, all the conditions I described in the previous section of my testimony – cost caps, operating audits, and performance measurement – should apply to all programs, including SOG, which the Commission elects to approve (if any).

Q. WHAT ARE YOUR CONCERNS ABOUT DUKE ENERGY'S $48 MILLION ADMS PROPOSAL?

[13] DEC response to NCJC DR 4-06, attached as Stephens Exhibit 3.

A. ADMS consists of a suite of software applications that are then combined into a single operating platform. In my experience, the value comes from the underlying software applications, including fault locating, isolation and service restoration ("FLISR") and integrated Volt-VAR control ("IVVC"). In general, with the possible exception of outage management system integration, the combination into a single operating platform, though intuitively appealing, provides little actual economic benefit. Similarly, I have seen utilities waste tens of millions of dollars pursuing grid automation – enabling software, not grid operators in control centers – to reconfigure the grid. Not only is this sort of automation extremely costly to implement, to little economic benefit, it requires an extreme, ongoing level of dedication and attention to field device software updates, GIS map system accuracy, accurate location and device setting monitoring, communications network attention, and logical equipment identification. If the logical specifications do not precisely match physical specifications, for every device, 100% of the time, automation efforts will fail.[14] When O&M budgets are stretched, or under the pressure of a service restoration effort, humans take shortcuts. Full grid automation, where some see ADMS heading, thus requires a level of management and employee attention that may be unattainable, and involves a great deal of risk. Due to the underlying suite of software applications, I hesitate to recommend the Commission reject ADMS. But, due to the

[14] Many of these concerns are described in a US Department of Energy whitepaper dedicated to the subject. US Department of Energy. *Voices of Experience: Insights into Advanced Distribution Management Systems*. Whitepaper. February, 2015, https://www.energy.gov/sites/prod/files/2015/02/f19/Voices%20of%20Experience%20-%20Advanced%20Distribution%20Management%20Systems%20February%202015.pdf.

challenges and overreaches I describe, I absolutely recommend the Commission apply cost cap and operating audit conditions to any self-optimizing grid and ADMS capital spending the Commission might approve.

B. Transmission Hardening and Resilience (Excluding Flood and Animal Mitigation)

Q. WHAT MATERIAL MODIFICATIONS DO YOU RECOMMEND FOR DUKE ENERGY'S TRANSMISSION HARDENING AND RESILIENCE PROGRAM?

A. While my suggested modifications to the self-optimizing grid program amounted to a relatively simple reduction in scope, my suggested modifications to the transmission hardening and resilience program amount to a complete redesign of the program and a repurposing of the $120 million transmission hardening and resilience budget (excluding substation flood and animal mitigation components, which I included in the "merit approval" category).

Q. WHY DO YOU RECOMMEND THE TRANSMISSION HARDENING AND RESILIENCE BUDGET BE COMPLETELY REPURPOSED?

A. Duke Energy describes its transmission hardening and resilience program as a way to improve reliability, projecting that ratepayers will receive $2 billion in economic benefits. However, given the extremely low historical failure rates of the 44kV equipment DEC proposes to replace, including conductors, static lines, and support structures, there is no way the replacements proposed can possibly avoid the number of failures required to produce the economic benefits projected.[15] In my experience, low transmission failure rates are common, as transmission designers recognize the larger number of ratepayers impacted by failures on such systems, and overbuild accordingly. But my concerns regarding benefit projects are trumped by an even bigger concern: the transmission hardening and restoration program proposed will not increase the capacity of the 44kV system to accommodate greater DER capacity by a single watt.

Q. ARE YOU SURE? DUKE ENERGY'S GIP STATES ITS TRANSMISSION AND RESILIENCE PROGRAM "BEGINS TO PAVE THE WAY FOR MORE DER INTERCONNECTIONS."

A. In replacing 44kV lines, Duke Energy is replacing the support structures (poles) with stronger structures (towers) designed to hold the heavier weight of 100kV conductor. However, Duke Energy is not replacing any of the other 44kV equipment on these lines – switches, voltage regulators, circuit breakers, etc. – with 100kV equipment. Without such equipment, Duke Energy will be unable to operate the new lines at 100kV. This does not represent standard industry practice. In Phase 1, Duke Energy is investing as much capital as it can justify while accommodating as little new DER as possible (in this case, zero). In Phase 2, with no defined timeframe, Duke Energy would actually install the equipment required to operate the lines at 100kV; in Phase 3, with no defined timeframe, Duke Energy will expand the 44kV network to more substations. Phases 2 and 3 will increase the DER capacity Duke Energy's grid can accommodate; Phase 1 will not. Nor, as described above and by Witness Alvarez, will Phase 1 deliver

[15] Witness Alvarez provides these historical failure rates in his testimony.

the reliability benefits Duke Energy projects. My recommendation is to repurpose the $120 million Duke Energy proposes to invest in Phase 1 in a smaller number of projects incorporating Phases 2 and 3. Stakeholder engagement would be valuable in allocating this capital in ways that maximize the amount of new DER capacity accommodated for the least cost. The deficiencies in Duke Energy's 44kV upgrade proposal illustrate the potential value of a transparent, stakeholder-engaged distribution planning and capital budgeting process.

V. GIP Programs That Should Be Rejected Due to Lack of Cost Effectiveness/Compliance with Standard Industry Practice

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I will discuss GIP programs that should be rejected in any scenario. None of these programs are standard industry practice as they are generally recognized as not cost-effective. They include:

- Targeted Undergrounding ($114.5 million);
- Distribution Transformer Retrofits ($118.0 million);
- Transformer Bank Replacements ($116.4 million);
- Oil-Filled Breaker Replacements ($200.3 million); and
- Substation Physical Security ($110.7 million).

A. Targeting Undergrounding

Q. WHY DO YOU BELIEVE TARGETED UNDERGROUNDING MERITS REJECTION?

A. Undergrounding of overhead lines is not a standard industry practice for many reasons. Undergrounding may be intuitively appealing, but it is not the panacea that utilities would like stakeholders to believe. While undergrounding reduces the risk of service interruptions due to vegetation contact and weather, it increases the risk of service interruptions due to flooding and digging. While undergrounding reduces the hassle associated with repairing lines in residential ratepayers' backyards, the time to locate and repair underground faults generally takes longer than the time to locate and repair faults on overhead lines. While aesthetically appealing in principle, in practice almost 100% of utility poles will remain in place, supporting telephone, Internet, and cable television service lines. While undergrounding may eliminate a small portion of Duke Energy's tree trimming costs, some other service provider will still need to clear vegetation, that means ratepayers will still pay; underground cable is also more costly than overhead conductor, and must be replaced more frequently. A Lawrence Berkeley National Laboratory review of undergrounding programs also noted an increase in utility employee safety risks associated with undergrounding.[16]

Furthermore, undergrounding is extremely costly and not cost-effective, and it is not simply my experience that tells me so. The Lawrence Berkeley National Lab undergrounding study indicates that the benefit-to-cost ratio of undergrounding is 0.3 to 1.0 (that is, costs exceed benefits by a factor of more

[16] Larsen P. A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution Lines. Lawrence Berkeley National Laboratory. October 2016. Page 7.[17] Ibid, parts of the document not paginated, see PDF file page 42.

than three).[17] For these reasons, the Virginia State Corporation Commission ("SCC") rejected undergrounding programs proposed by Dominion multiple times. Duke Energy's program proposes to underground the lines serving just 22,477 ratepayers[18] at a cost of $169.3 million,[19] or at least $7,500 per ratepayer undergrounded. To justify the program, Duke Energy claims that undergrounding will reduce the momentary outages to commercial and industrial ("C&I") ratepayers upstream of the residential areas. In fact, Duke Energy attributes of 90% of the benefits it projects from targeted undergrounding to this single value proposition.

Q. DO YOU BELIEVE THAT JUSTIFYING THE INSTALLATION OF TARGETED UNDERGROUNDING BASED ON THE EFFECT OF UPSTREAM MOMENTARY OUTAGES IS INAPPROPRIATE?

A. As indicated in Mr. Alvarez's testimony, the cost per momentary outage to various rate class ratepayers is exaggerated. In addition, I would like to point out a few factors that contribute to Duke Energy's exaggeration of the amount of upstream momentaries caused by backlot line overhead lines.

First, Duke Energy admitted in discovery that not all outages result in an upstream momentary event.[20] The purpose of coordinating the operation of fuses with upstream devices is often intended to eliminate an upstream operation. That is to say, that the upstream relay is set such that the downstream fuse will clear or

[17] Ibid, parts of the document not paginated, see PDF file page 42.
[18] Oliver Direct, Ex. 7 workbook "TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx", tab "Area Data – Condensed", line "Total Ratepayers Affected".
[19] Ibid, tab "All Years Tab Summary", cell D21.
[20] DEC response to NCSEA DR 3-32, attached as Stephens Exhibit 4.

blow, for faults of sufficient magnitude, resulting in no upstream momentary outage.

Second, the reason for most momentary outages is that the utility has installed a "Fast" or "Fuse Saving" relay setting on the upstream device, which is designed to open the upstream device and allow a fault to clear. This opening operation is the momentary outage. These upstream device settings are typically set for one fast trip before moving to the slower trips which would cause a downstream device such as a fuse to clear. The point is, a simple adjustment to upstream device trip settings can eliminate C&I momentaries caused by downstream events.

Third, Duke Energy's reliability improvement estimates assume 2.7 momentaries for every sustained outage. I believe this estimate is too high. As indicated above, relays are typically set for one fast trip, not multiple fast trips, which would result in one momentary upstream outage before the fuse clears, not 2.7. The fuse again would be coordinated with the relay setting following the "Fast" trip setting such that the fuse would clear prior to the upstream device opening again after the fast trip opening. This would result in one momentary for upstream ratepayers. The only reasonable course of action is to evaluate the upstream momentaries on a circuit-by-circuit basis.

Fourth, Duke Energy admitted in discovery that eliminating the "Fast" Trip on the upstream device would eliminate most of the momentaries experienced by the upstream C&I ratepayers.[21] Duke Energy did point out that this would result in increased downstream outages and trips to the field; however, the value Duke Energy placed on upstream C&I ratepayer momentaries greatly outweighs the value of downstream outages. If this is the case, then the best course of action would be to eliminate the "Fast" trip setting on upstream devices rather than spend $114.5 million undergrounding downstream segments in just 55 neighborhoods.

Finally, I note that estimated economic benefits for many GIP programs consist largely or mainly of a reduction in upstream momentaries for C&I ratepayers. The preceding comments apply to all of these programs.

B. Distribution Transformer Retrofits

Q. WHY DO YOU BELIEVE THE DISTRIBUTION TRANSFORMER RETROFIT PROGRAM MERITS REJECTION?

A. The distribution transformer retrofit program that Duke Energy is proposing is not standard practice, and is not likely cost-effective. Duke Energy operates 784,000 distribution transformers in North Carolina; in an average year slightly fewer than 6,000 of them, or less than 1%, will fail.[22] As with targeted undergrounding, the value proposition proffered by Duke consists almost entirely of protecting C&I ratepayers from downstream service outages; 93% of the benefits Duke Energy projects stem from this claim.[23] Duke indicates that the transformers and

[21] DEC response to NCJC DR 5-33, attached as Stephens Exhibit 5.
[22] Oliver Direct, Ex. 7 workbook "HR_Transformer Retro_DEC-DEP_NC_19-22_vF_rev2 8-2-19.xlsx", tab "Selection Metric – Tx Retrofit NC", cell C31 plus cell C34 (incidents) divided by cell 65 (total transformer count).
[23] Ibid. Tab "NPV-Tx Retrofit NC".

secondary systems that are planned for retrofit are operating safely.[24] Additionally, Duke could provide no indication of outages or outage complaints associated with these transformers on secondary lines[25]

Duke indicated that many of the transformers that are involved in the retrofit project are Completely Self Protected ("CSP") transformers.[26] These transformers have internal fuses that protect the transformer from internal faults. Thus, even though the distribution transformer retrofit project is intended to protect the transformer and the secondary line, the program is duplicative for the transformer portion of the value proposition.

In discovery, Duke Energy indicated the trip setting on the transformer retrofit devices would be set such that the retrofitted distribution transformer would trip before any upstream devices could trip.[27] This is counterproductive. The reason for enabling a fast trip setting on upstream devices is to allow a fault to clear before the downstream device (in this case the retrofitted distribution transformer) clears or opens. The transformer retrofit program would install a device downstream that clears or opens before the upstream fast trip device can prevent it from operating. This is clearly counterproductive and a waste.

C. Transformer Bank Replacement

Q. EXPLAIN WHY THE TRANSFORMER BANK REPLACEMENT PROGRAM SHOULD BE REJECTED.

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[24] DEC response to NCJC DR 8-34, attached as Stephens Exhibit 6.
[25] *Id*.
[26] Stephens Exhibit 6. DEC could not provide an exact count; however, most of the distribution transformers installed by utilities in the last 40 years have been of the CSP type.
[27] DEC response to NCJC DR 5-40, attached as Stephens Exhibit 7.

A. Substation transformers are typically situated in groups of three, constituting a transformer bank. Unlike distribution transformers, substation transformers (also known as transmission transformers) typically serve one or two thousand ratepayers each. However, as transformer oil can be tested, and used to predict transformer failure, there is no reason whatsoever to replace transformers in the absence of test results. As a result, substation transformer oil testing and failure prediction is a standard industry practice; prospective substation transformer replacement in the absence of test results is not.

Witness Alvarez provides historical substation transformer failure rates in his testimony; they are extremely low, as I would expect. The large benefits Duke Energy projects from avoiding future transformer failures through prospective replacement do not square at all with historically low transformer failure rates. Prospective substation transformer replacement, and particularly the proactive replacement of entire transformer banks, in the absence of test results, should be rejected.

D. Oil-Filled Breaker Replacement

Q. EXPLAIN WHY THE OIL-FILLED BREAKER REPLACEMENT PROGRAM SHOULD BE REJECTED.

A. Circuit breakers, like transformers, can be tested. It is standard industry practice to test circuit breakers at regular intervals, and to track the number of operations (trips) for each breaker. When a circuit breaker fails a test, or reaches its rated number of operations, it is standard industry practice to replace it. Replacing circuit breakers in the absence of test failure or operating counts is not standard practice.

Again, there is a reason prospective circuit breaker replacement is not standard industry practice. Witness Alvarez provides historical circuit breaker failure rates in his testimony; as with transformer failures, the failure rate has been extremely low. The large benefits Duke Energy projects from avoiding future circuit breaker failures through prospective replacement do not reconcile with historically low transformer failure rates.

Q. BUT DUKE ENERGY DESCRIBES BENEFITS OTHER THAN RELIABILITY IMPROVEMENTS FROM CIRCUIT BREAKER REPLACEMENT, DOES IT NOT?

A. Yes. Duke Energy claims that the new circuit breakers will have remote monitoring and control capabilities that the oil circuit breakers do not have. While this may be true, I note that retrofit kits are available to provide these same capabilities for oil circuit breakers at the fraction of the cost of a new circuit breaker. Duke Energy also claims that about one-third of the economic benefits of the circuit breaker replacement program stem from the avoidance of replacement in the future. I do not see this as a "benefit" at all. When a circuit breaker needs to be replaced, it should be replaced. Replacing a circuit breaker before it becomes necessary to do so does not avoid any costs at all; rather, it advances the cost, requiring ratepayers to pay today for something they could have been spared until some future test failure. I note Duke Energy applies this nonsensical benefit to other programs too, including targeted undergrounding and transformer bank replacement. Witness Alvarez quantifies this in his testimony regarding overstated benefits.

E. Substantion Physical Security

Q. EXPLAIN WHY THE PHYSICAL SUBSTATION SECURITY PROGRAM SHOULD BE REJECTED.

A. As with the other programs that merit rejection, there is no standard industry practice or security standard associated with the physical substation security upgrades Duke Energy is proposing. The physical substation security program includes the installation of high-security fencing, gates, cameras, and lighting at a cost of $4.2 million per substation. This amount includes $800,000 per substation just for a prefabricated building to house physical security equipment.[28] At a proposed budget of $110 million, this program will upgrade the physical security of just 27 substations. Although that will leave Duke Energy with 2,088 (99%) of its substations with standard fencing, I am pleased to report that Duke Energy has never recorded a single incident of unauthorized substation intrusion.[29] There must be more valuable ways for Duke Energy to deploy capital, and this proposed program illustrates another potential opportunity for a transparent, stakeholder-engaged distribution planning and capital budgeting process to create value for ratepayers.

VI. GIP Programs That Should Be Rejected Pending Further Evaluation

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

[28] DEC response to NCJC DR 2-4, attached as Stephens Exhibit 8.
[29] DEC response to NCSEA DR 2-19 (b), attached as Stephens Exhibit 9.

A. In this section of my testimony, I will describe GIP programs that should be rejected pending further evaluation, because critical evaluations are missing that will require extensive effort beyond the scope of this proceeding. I will also identify opportunities for a transparent, stakeholder-engaged distribution planning and capital budgeting process to deliver value when considering these types of programs. Programs that should be rejected pending further evaluation include:

- Enterprise Communications Mission Critical Voice, Data ($52.5, $107.1 million);
- Distribution Automation ($194.3 million); and
- Transmission System Intelligence ($86.4 million).

A. Mission Critical Voice and Data Network Programs

Q. WHAT CRITICAL EVALUATIONS ARE MISSING FROM DUKE ENERGY'S PROPOSED VOICE AND DATA NETWORK DEVELOPMENT PROGRAMS?

A. Witness Alvarez describes the evaluations missing from these proposed programs, so I will not repeat those here. While neither Witness Alvarez nor I are communications experts, I appreciate his concern that Duke Energy completed no technical or economic make vs. buy evaluation of alternatives to Duke Energy's $160 million proposal to build proprietary voice and data communication networks. In this Internet of Things age, when public wireless carriers are introducing high data transfer rates, dedicated bandwidth, and ever-improving cybersecurity capabilities, it seems more than appropriate to me that an in-depth evaluation of Duke Energy's claimed voice and data requirements, along with potential options to satisfy them, be conducted. Stakeholders may need to enlist expert services to properly participate in such an effort, but that seems preferable to "waving through" a $160 million investment that has not been thoroughly evaluated. Due to the lack of technical or economic make vs. buy analyses, I agree with Witness Alvarez that this GIP program be rejected pending a more thorough evaluation.

B. *Distribution Automation and Transmission System Intelligence Programs*

Q. WHAT CRITICAL EVALUATIONS ARE MISSION FROM THE DISTRIBUTION AUTOMATION AND TRANSMISSION SYSTEM INTELLIGENCE PROGRAMS?

A. Duke Energy provides no benefit-cost analyses for these programs, claiming they are "modernization" programs. I do not understand why categorizing them as modernization programs excuses Duke Energy from the obligation to conduct benefit-cost analyses. Indeed, in GIP descriptions of these programs, improvements in reliability and resilience are featured. For all other GIP programs in which improved reliability and resilience are claimed, benefit-cost analyses were developed; why not for these two programs?

I agree that benefits can be difficult to quantify for some programs, and that some programs merit approval without a benefit-cost analysis, or with a negative benefit-cost analysis. Indeed, I categorized several GIP programs as "merit approval with conditions" despite the lack of a benefit-cost analysis. However, it seems to me that anticipated reliability and/or resilience benefits should be quantified for any program that is promoted as beneficial to these outcomes. Failure to quantify the benefits of programs that offer quantifiable benefits represents a lack of accountability for benefit delivery. I therefore recommend the Commission reject these programs until Duke Energy completes benefit-cost analyses for them.

VII. Summary and Recommendations

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. I began my testimony with context, describing how utilities have conducted distribution planning to incorporate new technologies and technical challenges for over a century. I then discussed how investor-owned utilities are changing their approach from distribution planning to a focus on maximizing capital investment. I presented historical evidence indicating that the reliability of Duke Energy's grid in North Carolina has deteriorated significantly in recent years despite dramatic increases in grid investment, confirming locally the phenomenon Witness Alvarez describes nationally: grid reliability does not necessarily improve with grid investment.

My testimony then continued with critical evaluations of the individual programs or sub-components that make up Duke Energy's GIP. My testimony placed Duke Energy's GIP programs and sub-components into one of five categories: (1) Those that merit approval with conditions; (2) Those that only merit approval with material modifications and conditions; (3) Those that do not merit approval due to lack of cost-effectiveness/compliance with standard industry practices; (4) Those that merit rejection pending further evaluation; and (5) Those being considered in other dockets. I justify categorization through testimony which evaluates the relative merits of each GIP program and sub-component relative to costs, or identifies missing information prohibiting such evaluation. My testimony also describes the general conditions I recommend the Commission establish for any GIP program it approves, and modifications specific to the self-optimizing grid and transmission hardening & resilience programs. My testimony concludes with recommendations for the Commission's consideration, including both primary and secondary (program-specific) recommendations.

My primary recommendation, consistent with Witness Alvarez's recommendation, is for the Commission to reject Duke Energy's GIP. Instead, I recommend the Commission establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process. Witness Alvarez's testimony provides additional descriptions and justifications for such a process. In the event the Commission rejects my primary recommendation, I recommend the Commission follow my program-specific guidance as secondary recommendations. I also describe conditions I recommend the Commission establish for any GIP programs approved, including (1) performance measurement; (2) cost caps and associated operating audits; and (3) rejection of cost recovery for assets placed into service in the test year that are not standard industry practice/not cost effective. I also recommended the Commission reject deferral accounting because I believe the practice encourages investment in sub-optimal grid programs. My testimony describes why many GIP programs are sub-optimal.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does. However, I may seek to supplement this testimony, either by filing or during the evidentiary hearing, after seeing a demonstration of how Duke Energy used the Copperleaf C55 software to develop transmission hardening and restoration program benefit estimates.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Dennis Stephens on Behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and North Carolina Sustainable Energy Association either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 18th day of February, 2020.

s/ Gudrun Thompson

Gudrun Thompson

(Whereupon, the prefiled direct testimony of Rory McIlmoil was copied into the record as if given orally from the stand.)

(Whereupon, Exhibit RM-1 was admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. DOCKET NO. E-7, SUB 1214

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Carolinas, LLC	)	**RORY McILMOIL FOR**
For Adjustment of Rates And Charges	)	**CENTER FOR BIOLOGICAL**
Applicable to Electric Service	)	**DIVERSITY AND**
in North Carolina	)	**APPALACHIAN VOICES**

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I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION.

A: My name is Rory McIlmoil. My business address is 589 W. King Street, Boone, NC 28607. I am the Senior Energy Analyst at Appalachian Voices.

Q: WHAT ARE YOUR RESPONSIBILITIES IN THIS ROLE?

A: In my role as Senior Energy Analyst, my responsibilities include researching energy policy models, analyzing the impact on ratepayers and the environment of policies my organization might support or oppose, assisting in the drafting of energy-related legislation, and advocating for utility clean energy programs and rate structures that equitably benefit families and local communities.

Q: PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A: I graduated from Furman University with a Bachelor of Science in Earth and Environmental Science and received a Master of Arts in Global Environmental Policy from American University's School of International Service. I began my professional career serving as the Energy Program Manager with Downstream Strategies, an environmental and energy consulting company based out of Morgantown, West Virginia, where I was responsible for energy and economic research and consulting, project development and local clean energy planning. I joined Appalachian Voices in 2013 as the Energy Savings Program Manager, analyzing and advocating for equitable energy efficiency finance programs and rate structures through North Carolina's rural electric cooperatives.

More specifically as it pertains to equitable programs, I worked to promote the development of utility energy efficiency finance programs that were accessible to all residents regardless of income, credit score, and whether they owned their home or apartment. In terms of rates, I have advocated for residential rate structures through North Carolina's rural electric cooperatives that more accurately reflect "fixed" and "variable" costs, resulting in lower monthly fixed charges, and have also promoted solar net-metering rates that properly value customer-generated solar energy and do not penalize co-op members for investing in on-site distributed solar. I was promoted to Senior Energy Analyst in 2018, and have since focused my efforts on state energy policy.

My resume is attached as Exhibit RM-1.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER REGULATORY COMMISSION RELATING TO YOUR CURRENT RESPONSIBILITIES?

A: No. This is the first time I am testifying before this Commission or any other regulatory body.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of the Center for Biological Diversity and Appalachian Voices.

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

A: The purpose of my testimony is to address the impacts that this Application – specifically, Duke Energy Carolinas, LLC's ("Company" or "DEC") proposal to increase rates and raise the return on equity ("ROE") – will have on low-income households, specifically on the home energy cost burden those households experience. In light of these effects, my testimony will propose that the Commission strongly consider these impacts of DEC's proposal on household energy burden, and give substantial and due weight to those impacts in the Commission's consideration of "changing economic conditions" and "ability of customers to afford" the proposed rate increase and ROE.[1]

Q: PLEASE SUMMARIZE YOUR KEY POINTS AND FINDINGS.

A: My testimony that follows will:

1) Discuss how household energy cost burden ("energy burden") serves as the most accurate descriptor of a customer's ability to (a) pay their electric bill, and (b) afford a rate increase, and show that trends in energy burden over time provide a more accurate representation of "changing economic conditions" than do changes in unemployment rates, median incomes or

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[1] State of North Carolina Utilities Commission, Proposed Order of the Public Staff. "In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina" (April 27, 2018), p. 79-88. Docket Nos. E-7, sub 819, 1110, 1152, 1146 (emphasis added). https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=c8bc297a-a1f5-4371-8832-de9a9029e913

county economic indicators, and thereby should be factored into the Commission's decision-making in this proceeding;

2) Provide a detailed description and the results of my analysis showing how DEC's proposed rate increase will increase the energy burden experienced by households served by DEC that fall under 150 percent of the Federal Poverty Level ("FPL")[2], including the particular findings that:

a) High energy-burdened households – defined as carrying an energy burden of 10.9 percent or higher[3] – constituted one out of every 12 households served by DEC in 2016 and again in 2019. If DEC's proposed rate increase is approved, the number of high energy-burdened households would be further exacerbated to one out of every nine households by 2021, and one out of every eight households by 2025.

b) If the rates proposed in this present case are approved, nearly two-thirds of all low-income households served by DEC will be characterized as experiencing a "high household energy burden" by 2025 representing an increase of approximately 50 percent from current conditions.

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[2] The US Department of Health and Human Services identifies 150 percent of the FPL as the maximum income allowed to be eligible for Low-Income Home Energy Assistance Program funding. For that reason, this is the threshold used to define low-income households for the purpose of this testimony. LIHEAP Service Eligibility Guidelines, available at https://www.acf.hhs.gov/ocs/resource/liheap-eligibility-criteria.

[3] Applied Public Policy Research Institute for Study and Evaluation (APPRISE). Jul 2005. LIHEAP Energy Burden Evaluation Study: Final Report. Prepared for the US Department of Health and Human Services. At p. 12. https://www.acf.hhs.gov/sites/default/files/ocs/comm_liheap_energyburdenstudy_apprise.pdf

c) Combined, if DEC's current request for a rate increase is approved, annual electric bills for low-income households will have increased by approximately $138 per year ($11.48 per month), on average, between 2016 and 2025 – a 10.6 percent increase in a decade. The large majority of the impact would result from DEC's proposed rate increase.

3) Discuss how, despite the increase in energy burdens for low-income households served by DEC, the Company has invested little to address that problem, and its proposals for investing in energy efficiency generally, and specifically supporting low-income residents in the present rate case do little to mitigate the impacts of the Company's proposed rate increase on household energy costs and energy burdens.

4) Present findings of my analysis of how lower ROEs and a maintaining of DEC's current equity-to-debt ratio of 52 percent and 48 percent, respectively, will benefit residential ratepayers – and thus low-income, energy-burdened households – through a smaller increase in residential rate revenues.

Q: PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS IN THIS CASE.

A: To mitigate and minimize the impact of DEC's proposed rate increase on low-income, energy-burdened households, I recommend:

1) That the Commission expand the list of factors it considers in weighing "changing economic conditions" and the "ability of customers to afford" the proposed rate increase and ROE to include how these cost increases will

impact energy burdens for low-income households. Historically, energy burdens have been ignored by the Commission, despite the factor's presence in other jurisdictions.

2) That the Commission strongly examine all costs for which DEC is proposing to recover in the present rate case through a lens of whether DEC's justification of those costs is sufficient to warrant enhancing the real and significant burden of energy costs on low-income families.

3) That the Commission, in order to mitigate the impact of the Company's proposal on low-income households, reject DEC's proposal for a 10.3 percent ROE, and instead approve a ROE of no greater than 9.2 percent, which is the ROE recently approved by the Virginia State Corporation Commission ("SCC") for Dominion Energy Virginia ("Dominion")[4], and maintain DEC's current capital structure of 52 percent equity and 48 percent debt.

4) That the Commission require DEC to take household energy burden into account as part of the Company's assessment of trends in "changing economic conditions" in North Carolina and the application of that assessment to calculating and proposing its ROE.

5) That DEC recognize and accept "the definition and use of the phrase 'energy burden,'" and make a more concerted and immediate effort to invest in low-

[4] Commonwealth of Virginia State Corporation Commission. Final Order. Case No. PUR-2019-00050, "For the determination of the fair rate of return on common equity." Nov 21, 2019. http://www.scc.virginia.gov/docketsearch/DOCS/4jx901!.PDF

income energy efficiency and demand-side management programs at a scale of investment sufficient to meet the scale of the problem.

II. IMPACTS OF DEC'S REQUESTED RATE INCREASE ON RESIDENTIAL ELECTRIC BILLS, WITH A FOCUS ON LOW-INCOME HOUSEHOLDS

Q: PLEASE SUMMARIZE DEC'S PROPOSED RATE INCREASE AND THE COSTS THE COMPANY IS PROPOSING TO RECOVER.

A: In this rate case, as outlined in DEC's Application, the Company is proposing to increase rates in order to recover more than $3 billion in costs incurred during the Test Year. This includes more than $2.2 billion for transmission and distribution[5] upgrades and maintenance – including approximately as much as $224 million for already-incurred "grid improvement" expenses[6], more than $600 million for coal ash compliance costs,[7] at least $36 million for storm recovery expenses,[8] and tens of millions more for the accelerated depreciation of coal-fired power plants and other items.[9]

To recover these costs, DEC is requesting an increase in its retail revenues of approximately $445.3 million, representing a 9.2 percent increase

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5 NCUC E-7, Sub 1214, DEC Witness Oliver Testimony at 7
6 DEC Response to CBD & AV DR 1-II-1, Attachment "Public Staff Data Request No. 78-4 GIP COSS follow up.xlsx
7 NCUC E-7, Sub 1214, DEC App. at 7.
8 NCUC E-7, Sub 1214, DEC App. at 4, 6.
9 NCUC E-7, Sub 1214, DEC App. at 8.

in annual revenues.[10] DEC is proposing to offset that increase by approximately $154.6 million in the first year (and by lower amounts in subsequent years) to refund ratepayers tax benefits DEC received as a result of the Federal Tax Cuts and Job Act.[11] DEC is proposing to refund ratepayers through a new Excess Deferred Income Tax (EDIT-2) Rider. The net impact of the refund would be to lower the increase in annual revenues to $290.8 million, representing an overall net increase in revenues – again, for the first year only – of 6 percent.[12] As the refund value declines in year 2 and beyond – as illustrated by DEC Witness McManeus[13] – the annual revenue requirement, and thus the percent increase in revenues, would subsequently increase above the year 1 values, resulting in higher rate and cost impacts for DEC ratepayers over time. These impacts will be further exacerbated by the expiration of the EDIT-1 Rider after August 1, 2022.[14]

A significant factor in the proposed revenue increase is DEC's request for an increase in the Company's ROE from 9.9 percent currently to 10.3 percent, and a shift in the capital structure from 52 percent equity and 48 percent debt back to a 53/47 ratio.[15] As will be explained later in my testimony, this

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10 NCUC E-7, Sub 1214, DEC App. at 4.
11 NCUC E-7, Sub 1214, DEC App. at 8.
12 *Id.*
13 Direct Testimony of Jane L. McManeus for Duke Energy Carolinas, LLC. Docket No. E-7, Sub. 1214. Exhibit 4, Page 2. Unless otherwise specified herein, all further references to testimonies pertain to those that were filed in this docket on behalf of DEC.
14 Duke Energy Carolinas, LLC. Rider EDIT-1. Excess Deferred Income Tax Rider (NC). https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-nc/ncrideredit.pdf?la=en
15 NCUC E-7, Sub 1214, DEC App. at 13.

proposal alone, assuming all costs for which DEC is seeking recovery are deemed "just and prudent," increases the amount of DEC's revenue request substantially above what it would otherwise be at lower ROEs and DEC's current capital structure, thereby placing a greater cost burden on ratepayers than would otherwise occur.

DEC further proposes, consistent with a "necessary" and "gradual" shift of each customer class's current revenue contribution to the overall rate of return average and the modification of rate schedules to "reflect more accurately the cost of service,"[16] a gross (pre-refund) increase of 10.3 percent in residential rate revenues, 7.1 percent for the general service class, 5.2 percent for the industrial class, 8.6 percent for the OPT class and 17.7 percent for the lighting class. With the application of the tax refund, the net increase for the residential class would be 6.7 percent, with other net increases being 4.8 percent for general service, 3.3 percent for industrial, 5.4 percent for OPT and 12.3 percent for lighting.[17]

Again, it is important to note that the net increase values only represent the first-year impacts of DEC's requested rate increase. Subsequent year impacts will be higher as the tax refund value declines and the EDIT-1 Rider expires in 2022. However, DEC does not detail what those impacts will be beyond year 1.

Q: HOW DOES DEC DESCRIBE THE IMPACTS TO RESIDENTIAL RATEPAYERS FROM THE PROPOSED RATE INCREASE?

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[16] Duke Energy Carolinas, LLC. Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets. Docket No. E-7, Sub 1214. See p. 4.

[17] *Id*. See p. 18-19.

A: As already described, DEC is proposing an overall "rate increase" for the residential class of 10.3 percent, and accounting for the rate impacts of the proposed EDIT-2 Rider, the net increase would fall to 6.7 percent (in the first year).[18] These values represent an average that is inclusive of all residential rate schedules. DEC does not provide an estimate of the net increase in year 2 and beyond as the value of the tax refund and associated EDIT-2 Rider declines and the EDIT-1 Rider expires in August 2022.

To illustrate the impact of the proposed "rate increase" on the average residential ratepayer, characterized as a household that consumes an average of 1,000 kilowatt-hours ("kWh") per month, DEC estimates that the annual electric bill for that household would increase by approximately $8.06 per month (inclusive of all riders, including the year 1 EDIT-2 Rider) – or around $97 in the first year – representing a 7.45 percent increase in the annual electric bill.[19] However, DEC also estimates the impact for customers using both less and more than 1,000 kWh/month, and provides a breakout of the impact at various usage levels for customers on each of the residential rate schedules.[20]

Per DEC Witness Pirro, the example just provided is reflective of the impact on a customer on the residential RS rate schedule using 1,000 kWh/month.[21] However, per DEC's calculation, the impact for a household

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[18] NCUC E-7, Sub 1214, DEC App. at 18.

[19] Duke Energy Carolinas, LLC. Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets. Docket No. E-7, Sub 1214. See p. 4.

[20] Pirro Testimony at ex. 3, p.1-6.

[21] *Id.*

using 3,000 kWh/month, for instance, would be triple, resulting in an annual bill increase of $290, for an 8.2 percent increase.[22] Similarly, a household on the residential RE (all-electric) rate schedule using 1,000 kWh/month would see an annual bill increase of approximately $74 (5.78 percent), while one using 3,000 kWh per month would experience a first-year increase of more than $222 (6.38 percent).[23]

Thus, according to DEC, households on both rate schedules using less than 1,000 kWh/month would experience smaller increases in their electric bill. However, it is again important to note that these impacts are only first-year impacts, and will likely increase as the value of the tax refund and associated EDIT-2 Rider decline in year 2 and beyond and the EDIT-1 Rider expires in August 2022. Estimates of how those impacts will change over time are provided later in this testimony.

Q: WHAT IS YOUR RESPONSE TO DEC'S CHARACTERIZATION OF THOSE IMPACTS?

A: First, it is important to note that DEC is proposing to recover greater than 50 percent of the requested revenue increase from the residential class, claiming that doing so will better align costs with cost recovery.[24] As will be described later in my testimony, this proportional allocation only further exacerbates the increase in energy burden faced by low-income households served by DEC.

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22 *Id*. See ex. 3, p. 1.
23 *Id.*
24 Pirro Testimony at ex. 2, p.1-2.

While it may be general utility practice, DEC's characterization of the percent "rate increase" for the residential class is different from the *actual* increase in rates that ratepayers will see on their own rate schedules. As such, DEC's characterization misleads the Commission and the public and the media as to the actual rate impacts customers will experience.

As noted by the Commission in the 2018 DEC rate case, "Consumers pay rates, a charge in cents per kWh or per kW for the electricity they consume. . . Consumers do not pay a rate of return on equity."[25] In the same manner, ratepayers pay rates, a charge in cents per kWh, and they do not pay a "percent increase in rate revenues," which is what defines DEC's portrayal of a "rate increase." As detailed in the following section of my testimony, using DEC's red-line edited proposed rate schedules,[26] I have calculated the actual rate increase (percent increase in cents-per-kWh) for the residential RS and RE rate schedules (which combined accounted for more than 99 percent of residential accounts in 2018),[27] exclusive of any riders, to be 13.6 percent for the RS schedule, and 11.7 percent for the RE schedule – both of which are higher values than the 10.3 percent gross (pre-refund) "rate increase" described by DEC.

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25 State of North Carolina Utilities Commission, Raleigh. Proposed Order of the Public Staff "In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina." Docket E-7, Sub 1146. April 27, 2018. Page 80. https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=c8bc297a-a1f5-4371-8832-de9a9029e913

26 Duke Energy Carolinas, LLC NCUC Docket No. E-7, Sub 1214. NCUC E-1 Item 39(b), p. 2-6. https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=d1235600-3c77-4f3e-bec3-d347475469fe

27 DEC Response to CBD & AV DR 2-1. "DECNC Average Monthly Bills for Selected Scheduled from 2014 through 2018." Attachment "DEC CBD & AV DR 2-1.pdf"

Accounting only for the first year EDIT-2 Rider, I calculate that the net increase in RS and RE schedule rates would be 9.6 and 7.6 percent, respectively. This is merely to show the gross and net impact on actual 'rates" people pay on their bills, but again, these are both higher than the "net rate increase" described by DEC of 6.7 percent.[28]

While DEC's calculation of the impact of the rate increase on monthly electric bills for households at various usage levels is consistent with the actual increase in rates that customers would see in their rate schedule, it is more accurate and transparent to represent a rate increase as the "percent increase in rates" for customers on different schedules rather than as a "percent increase in residential rate revenues." Further, as also detailed in the following section of my testimony, DEC should project and describe future rate and bill impacts for customers on the RS and RE rate schedules that account for the estimated annual decline in the value of the annual tax refund – as it will necessarily result in an annual decline in the per-kWh EDIT-2 Rider value – as well as the expiration of the EDIT-1 Rider in August 2022. Combined, these two factors will lead to greater increases in household electric bills in year 2 and beyond than what DEC estimates the first-year bill impacts to be.

Q: HOW WILL THE PROPOSED RATE INCREASE AFFECT RESIDENTIAL RATE SCHEDULES, NOW AND IN THE FUTURE?

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[28] NCUC E-7, Sub 1214, DEC App. at 18.

PLEASE INCLUDE THE IMPACT OF THE PROPOSED EDIT-2 RIDER AND EXPIRATION OF THE EDIT-1 RIDER.

A: As noted, the RS and RE rate schedules comprise more than 99 percent of all DEC residential accounts in North Carolina. Additionally, more than half of DEC's proposed revenue increase would impact the residential class,[29] thereby resulting in a higher rate impact than would occur under a more equitable allocation of cost recovery. To DEC's benefit, the proportional allocation of the tax refund closely aligns with that of the revenue increase.[30]

The values for the gross and net (w/ EDIT-2 Rider) increase in the energy rates for the residential RS and RE rate schedules described in the last section are illustrative in (a) showing the actual impact on rates with and without the EDIT-2 Rider, and (b) comparing those with the "rate increase" described by DEC. However, assessing the full impact on rates requires including all riders applicable to residential rate schedules.

In addition to the EDIT-2 Rider (proposed), there are six energy (kWh)-based riders that impacted the actual rates households paid in 2018-2019. These include:

1) EDIT-1 (set to expire in August 2022)
2) Fuel Cost Adjustment Rider
3) Energy Efficiency Rider
4) Existing DSM Program Costs Adjustment Rider

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[29] NCUC E-7, Sub 1214, DEC Pirro Testimony at ex. 2, p. 1-2.
[30] *Id.*

5) BPM Prospective Rider

6) BPM True-Up Rider[31]

Table 1, below, details the current and proposed base rates for the RS and RE schedules,[32] the adjustments made to those base rates from each rider,[33] the final adjusted rate, and the percent change in the base and final rates for current and proposed rates for each schedule. As the RE rate schedule is a tiered rate, there are two columns shown. RE-1 (my own notation) represents the rate in place (and proposed) for the months of July through October, and for all energy consumed per month that is less than 350 kWh for the months of November through June. RE-2 represents the rate in place (and proposed) for all energy consumed above 350 kWh in the months of November through June.

As shown in **Table 1**, with all riders included – including the proposed EDIT-2 Rider – the net RS rate would increase by 8.7 percent, while the net RE-1 rate would increase by 6.8 percent, and the net RE-2 rate by 6.2 percent. While not shown, without the EDIT-2 Rider, the net rate increases including all other riders would be 12.5 percent, 10.6 percent and 10.5 percent, respectively.

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31 DEC Response to Intervenors Request DR 2-5. Summary of Rider Adjustments (2015-2019). Attachment "DEC CBD & AV DR 2-5_RiderValues.pdf"

32 Duke Energy Carolinas, LLC NCUC Docket No. E-7, Sub 1214. NCUC E-1 Item 39(b), p. 2-6. https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=d1235600-3c77-4f3e-bec3-d347475469fe

33 DEC Response to Intervenors Request DR 2-5. Summary of Rider Adjustments (2015-2019). Attachment "DEC CBD & AV DR 2-5_RiderValues.pdf." See North Carolina Fortieth Revised Leaf No. 99, page 1.

Table 1: Net impact of DEC's proposed rate increase for the residential RS and RE rate schedules, with all existing and proposed riders[34]

	RS		RE-1		RE-2	
	Current	**Proposed**	**Current**	**Proposed**	**Current**	**Proposed**
Base rate (¢/kWh)	8.7179	9.9059	8.5808	9.5807	7.6361	8.5296
Percent change		13.6%		11.7%		11.7%
Riders (in ¢/kWh)	**Current**	**Proposed**	**Current**	**Proposed**	**Current**	**Proposed**
EDIT-2	0	-0.3521	0	-0.3521	0	-0.3521
EDIT-1	-0.1049	-0.1049	-0.1049	-0.1049	-0.1049	-0.1049
Fuel Cost Adjustment Rider	0.1675	0.1377	0.1675	0.1377	0.1675	0.1377
Energy Efficiency Rider	0.5320	0.5320	0.5320	0.5320	0.5320	0.5320
Existing DSM Program Costs Adjustment Rider	-0.0043	-0.0043	-0.0043	-0.0043	-0.0043	-0.0043
BPM Prospective Rider	-0.0122	-0.0122	-0.0122	-0.0122	-0.0122	-0.0122
BPM True-Up Rider	-0.0040	-0.0040	-0.0040	-0.0040	-0.0040	-0.0040
Total Rider value (¢/kWh)	**0.5741**	**0.1922**	**0.5741**	**0.1922**	**0.5741**	**0.1922**
Final rate (¢/kWh)	**9.2920**	**10.0981**	**9.1549**	**9.7729**	**8.2102**	**8.7218**
Percent change		**8.7%**		**6.8%**		**6.2%**

The values shown in the **Table 1** above are only the year 1 values for RS and RE rates with the impact of all riders accounted for, including the EDIT-2 Rider. However, as the value of the tax refund is projected by DEC to decline in year

[34] Note(s): This is a snapshot only of current (2019) rates and riders for the RS and RE rate schedules, and how those will change if DEC's rate increase is approved as proposed. DEC's proposal includes the addition of the EDIT-2 Rider, as well as DEC's proposed decrease in the Fuel Cost Adjustment Rider (Duke Energy Carolinas, LLC NCUC Docket No. E-7, Sub 1214. NCUC E-1 Item 39(b), p. 76), which is reflected in the table. Additionally, while this table includes the EDIT-1 Rider and impact on rates, that rider is set to expire in August 2022, while the EDIT-2 Rider will begin declining in value at the same time, thereby increasing the net rate beyond what is shown in the table.

2 and beyond, the value of the associated EDIT-2 Rider rate is anticipated to decline as well.

The following **Table 2** shows DEC's projections for EDIT-2 refund values for years 1 through 5[35] – which DEC notes are "for illustrative purposes only" – as well as my estimate, for illustrative purposes, of the value of the EDIT-2 Rider in cents/kWh for years 2 through 5. The Rider value (in cents/kWh) for year 1 is as proposed by DEC, while subsequent years represent adjustments in direct proportion with DEC's projected decline in the total refund value.

Table 2: Projected decline of the EDIT-2 Rider value from year 1 to 5

Year	EDIT-2 refund value ($M)	EDIT-2 rate (¢/kWh)
1	$154.57	0.3521
2	$144.12	0.3283
3	$133.40	0.3039
4	$122.67	0.2794
5	$111.94	0.2550

DEC notes that the projected tax refund amounts for year 2 (assumed in this testimony to be 2022) through 5 (2025) are merely for illustrative purposes, and that actual values will be calculated prior to each successive year.[36] However, given the importance of understanding how a projected decline in the refund value over time, *combined with the expiration of the EDIT-1 Rider in August 2022,* will impact rates for the RS and RE rate schedules – and thus the total electric bills residents will pay, it is useful to apply the approximated EDIT-2

[35] NCUC E-7, Sub 1214, DEC Witness McManeus Testimony at ex. 4, p. 2.
[36] NCUC E-7, Sub 1214, DEC Witness McManeus Testimony at p. 36-37.

rates in the table above to the proposed residential RS and RE rates (including all other applicable riders) to estimate the actual net impact of DEC's proposed rate increase for households over time.

As shown in **Table 3** below, my projected EDIT-2 value for year 5, combined with the expiration of the EDIT-1 Rider after August 1, 2022, results in higher rates in year 5 (2025) than households would pay in year 1 (2021) with DEC's proposed rate increase. By 2025, the net rate increase for the RS rate schedule will be 10.8 percent (up from 8.7 percent for year 1, compared to current). The net increase for RE-1 will be 9.0 percent (up from 6.8 percent), and for RE-2 will be 8.7 percent (up from 6.2 percent). These values assume no further rate cases through 2025, that all other rider values remain constant and that no other riders are added to residential rate schedules.

Table 3: Impact of the projected decline of the EDIT-2 Rider value on residential electric rates from year 1 (2021) to year 5 (2025)[37]

	Final rates (w/ all riders, incl. EDIT-2)			
Rate schedule	**Current (¢/kWh)**	**2021 (¢/kWh)**	**2025 (¢/kWh)**	**Percent increase, current-2025**
RS	9.2920	10.0981	10.3001	10.8%
RE-1	9.1549	9.7729	9.9749	9.0%
RE-2	8.2102	8.7218	8.9238	8.7%

[37] The 2025 values reflect the projected decline in the EDIT-2 Rider from year 1 (2021) to year 5 (2025), as well as the expiration of the EDIT-1 Rider in August 2022.

The increase in the net residential rates as the value of EDIT-2 declines and EDIT-1 expires will result in higher bill impacts in year 2 and beyond than those estimated and presented for year 1 by DEC.

Table 4 (below) details the increase in monthly and annual electric bills that would result from DEC's proposed rate increase in year 1 for ratepayers on the residential RS rate schedule, which account for nearly 60 percent of all DEC residential accounts.[38]

Table 4: Estimated first-year bill impacts of DEC's proposed rate increase for ratepayers on the residential RS rate schedule[39,40]

kWh/month	Current bill ($/month)	Proposed (2021)	Monthly bill increase	Annual bill increase	Percent change
0	$15.85	$15.85	$0.00	$0.00	0.00%
500	$65.56	$69.87	$4.31	$51.75	6.58%
1,000	$115.27	$123.90	$8.63	$103.50	7.48%
2,000	$214.70	$231.95	$17.25	$207.01	8.03%
4,000	$413.55	$448.05	$34.50	$414.01	8.34%
6,000	$612.40	$664.15	$51.75	$621.02	8.45%

38 DEC Response to Intervenors Request DR 2-1. "DECNC Average Monthly Bills for Selected Scheduled from 2014 through 2018." Attachment "DEC CBD & AV DR 2-1.pdf"

39 The values for the current and proposed bill shown in this table differ from those presented by DEC for two reasons. First, DEC's values appear to be calculated based on a net rate that includes the value of the Job Retention Recovery Rider, which is .041 cents/kWh. However, that Rider was removed effective December 1, 2019. Second, DEC's values also exclude the 7 percent Combined General Rate Sales and Use Tax customers pay on the energy charge and Basic Facilities Charge. To provide a more accurate representation of the bill impacts that would result from DEC's proposed rate increase for residents on the RS rate schedule, I have excluded the value of the Job Retention Recovery Rider and have included the tax value, which increases in proportion with energy use. Results for some of the incremental levels of electricity consumption were excluded for simplicity, but those results are proportional to the level of energy use.

40 DEC Response to Intervenors Request DR 2-5. Summary of Rider Adjustments (2015-2019). Attachment "DEC CBD & AV DR 2-5_RiderValues.pdf." See North Carolina Fortieth Revised Leaf No. 99, page 1.

As shown above, a household on the RS rate schedule, using 1,000 kWh per month, would see an increase of $8.63 on their monthly electric bill in the first year as a result of DEC's proposed rate increase (see footnotes for an explanation as to why this value differs from DEC's calculated value). This represents a 7.48 percent increase, with the annual impact amounting to $103.50. For lower energy users, that impact would be less, while higher energy users would see a much greater increase – as much as an 8.45 percent increase for the highest energy users modeled, amounting to an annual increase of more than $620 in the first year (represented here as 2021). While that impact is significant, the anticipated decline of the EDIT-2 value through year 5 (2025), combined with the expiration of the EDIT-1 Rider in August 2022, will, all other factors being equal, result in a greater increase.

As shown in **Table 5**, the percent increase in electric bills for a household using 1,000 kWh per month is nearly 2 percent greater in 2025 than in 2021, rising from a 7.48 percent increase in 2021 (compared to current) to an overall 9.36 percent increase by 2025. Similarly, the monthly bill for the 1,000 kWh per month household will rise another $2 by 2025 (compared to 2021) as the EDIT-2 Rider value declines and the EDIT-1 Rider expires. ***That is 25 percent higher than the increase in the monthly bill that DEC estimates would result from its proposed rate increase in year 1.***

The highest energy users (6,000 kWh per month) would experience a monthly bill increase that is nearly $13 higher in 2025 than in 2021, and $64.72 per month higher than current – representing an overall 10.57 percent increase from current bills. For these higher energy users the overall bill increase above current levels would be approximately $777 a year by 2025.

Table 5: Bill impacts of DEC's proposed rate increase for ratepayers on the residential RS rate schedule in 2025

kWh/month	Current bill	Projected (2025)	Monthly bill increase	Annual bill increase	Percent change
0	$15.85	$15.85	$0.00	$0.00	0.00%
500	$65.56	$70.96	$5.39	$64.72	8.23%
1,000	$115.27	$126.06	$10.79	$129.44	9.36%
2,000	$214.70	$236.27	$21.57	$258.88	10.05%
4,000	$413.55	$456.69	$43.15	$517.76	10.43%
6,000	$612.40	$677.12	$64.72	$776.65	10.57%

Given the complexity of the rate schedule, a full analysis of bill impacts for 2021 and 2025 for various levels of electricity use that would result from DEC's proposed rate increase for customers on the residential RE rate schedule – which account for approximately 40 percent of all DEC residential accounts[41] – was not performed for this testimony.

However, for customers using 1,000 kWh/month, the current monthly electric bill for households on the RE schedule is approximately $102.33. DEC's proposal would increase that by $5.72 to $108.04 in 2021 (a 5.6 percent increase). Due to the projected decline in the EDIT-2 Rider value and the expiration of the EDIT-1 Rider in 2022, the monthly bill in 2025 is projected to be $110.06, or 7.6 percent above current levels (an increase of $7.74 per month). The annual bill increase in 2025, above current levels, would be $92.87. While

[41] *Id.*

this is a smaller increase than what households on the RS rate schedule would experience, it is still significant, and the impact over time should again be recognized and considered in the review of DEC's proposed rate increase.

This analysis shows that DEC should project and describe future rate and bill impacts for customers on the RS and RE rate schedules that account for the estimated annual decline in the value of the annual tax refund – as it will necessarily result in an annual decline in the per-kWh EDIT-2 Rider value – as well as the expiration of the EDIT-1 Rider in 2022. Only by doing so can DEC provide a transparent, complete and honest accounting of the impact its proposed rate increase will have now and in the future.

Q: WHAT IS YOUR MAIN CONCERN WITH THE IMPACT DEC'S PROPOSED RATE INCREASE WILL HAVE ON RESIDENTS, "NOW AND IN THE FUTURE"?

A: Despite the addition of the EDIT-2 Rider, my analysis shows that DEC's proposed rate increase will result in an immediate and significant increase in household electric bills, with that impact only worsening through 2025 as the value of the EDIT-2 Rider declines and the EDIT-1 Rider expires.

As my analysis in the previous section shows, the changing value of those two EDIT riders alone over the five-year time frame will, by 2025 (year five of my analysis), increase the monthly bill impact by more than an additional $2 per month above the impact the requested rate increase will have in year 1 for the 1,000 kWh per month household (and more for higher use households). This would bring the total five-year increase in monthly electric bills for that household to $10.79 per month. This is vitally important because every dollar increase in a household's monthly electric bill resulting from DEC's proposed rate increase should be viewed in a similar light as if DEC were proposing to increase the Basic Facilities Charge ("BFC") by, in the case of the 1,000 kWh per month households, nearly $11 per month.

While such an increase will be felt to some extent by all households, the impact of that increase will be felt far more strongly by the more than 330,000 low-income, energy cost-burdened households served by DEC that are already dealing with unaffordable energy costs. This is especially true in light of the fact that DEC is investing very little in low-income energy efficiency and is not proposing any substantial new investments in such programs in the present rate case.

Further, in its filing, DEC explains that the shift in more of the Company's cost onto the residential class and its proposed modification of rate schedules through the present rate case represents part of, as described by Witness Pirro, a "gradual" but "necessary" alignment intended "to reflect more accurately the cost of service" among customer classes.[42] This suggests that the Company is planning to continue that shift in future rate cases. Additionally, DEC Witness Pirro explicitly states that the BFC "will be addressed in future proceedings to properly reflect equitable cost-based rates that provide accurate

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[42] Duke Energy Carolinas, LLC. Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets. Docket No. E-7, Sub 1214. See p. 4.

price signals to our customers."[43] In other words, DEC intends to request additional increases in the BFC in future rate cases.

The increase in residential electric bills through the present case, in the first year and over the following four years, must not only be considered by itself, but also within the context of DEC's intention to shift more costs onto the residential class while also increasing the monthly BFC. It is vitally important for the Commission to consider all of these factors, especially in light of its mandate to consider "changing economic conditions" and "customers' ability to afford rate increases."

DEC's stated intention to increase costs for residential customers, through both the present and future rate cases, should itself be considered a "changing economic condition." This is especially true given the impact of that intention on customers' ability to afford rate increases. Lacking an equal percent shift in household income – not only on average, but specifically, and especially for those with household incomes that fall below 150 percent of the Federal Poverty Level ("FPL") – higher electric bills *now* impair the ability of customers to afford future rate increases.

Overall, my primary concern with DEC's proposed rate increase lies in the impact it will have on low-income households. As I will detail later in my testimony, virtually 100 percent of all low-income households served by DEC already, and have since at least 2016, experience annual energy bills that exceed

[43] Pirro Testimony at 12.

what is generally accepted as the "affordability" threshold of 6 percent of gross household income.[44] More than 40 percent of those households spent more than 10.9 percent of their gross household income on energy costs in the same year[45] – a level identified by the US Department of Health and Human Services ("DHHS") as the threshold for "high residential energy burden."[46]

DEC's proposed rate increase will, if approved, increase the average energy burden experienced by low-income households, and shift a substantial number of low-income households into the "high energy burden" category. Per my analysis, by 2025 nearly 210,000 households served by DEC – representing nearly one out of every eight of DEC's residential accounts in 2018[47] – will fall in the category of "high energy burden" if DEC's request is approved.

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44 Fisher, Sheehan and Colton. Home Energy Affordability Gap: Definitions. http://www.homeenergyaffordabilitygap.com/01_whatIsHEAG2.html

45 Calculated per the methodology described later in my testimony. In brief, however, the 40 percent value was calculated by downloading Census Tract-level data for household counts, home energy costs, median household income and percent energy burden for North Carolina households below 150 percent FPL from the USDOE's Low-Income Energy Affordability Data (LEAD) Tool, then using QGIS GIS software to extract the data for only the Census Tracts served by DEC. I was then able to analyze the average low-income household energy burden, count the number of households exceeding an average energy burden of 10.9 percent, and then calculate what portion of all low-income households served by DEC exceeded that threshold.

46 Applied Public Policy Research Institute for Study and Evaluation (APPRISE). Jul 2005. LIHEAP Energy Burden Evaluation Study: Final Report. Prepared for the US Department of Health and Human Services. https://www.acf.hhs.gov/sites/default/files/ocs/comm_liheap_energyburdenstudy_apprise.pdf

47 Number of residential accounts for 2018 provided by DEC in DEC Response to Intervenors Request DR 2-1. "DECNC Average Monthly Bills for Selected Scheduled from 2014 through 2018." Attachment "DEC CBD & AV DR 2-1.pdf"

III. IMPACTS OF DEC'S REQUESTED RATE INCREASE ON ENERGY BURDENS, WITH A FOCUS ON LOW-INCOME HOUSEHOLDS

Q: PLEASE DEFINE "ENERGY BURDEN" AND DESCRIBE WHAT IS CONSIDERED "UNAFFORDABLE" AND "HIGH ENERGY BURDEN."

A: As noted, "energy burden" is a widely recognized and well-known "phrase" and topic used and considered by government agencies, researchers, low-income advocates, housing advocates, energy efficiency and renewable energy advocates and other stakeholders. These include, but are not limited to: the US Department of Housing and Human Services[48]; the US Department of Energy[49]; the National Association of State Energy Officials[50]; the National Rural Electric Cooperative Association[51]; the National Governor's Association[52]; the National Consumer Law Center;[53] the American Council for an Energy Efficient

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[48] Applied Public Policy Research Institute for Study and Evaluation (APPRISE). Jul 2005. LIHEAP Energy Burden Evaluation Study: Final Report. Prepared for the US Department of Health and Human Services. https://www.acf.hhs.gov/sites/default/files/ocs/comm_liheap_energyburdenstudy_apprise.pdf

[49] USDOE. Low-Income Energy Affordability Data (LEAD) Tool. https://openei.org/doe-opendata/dataset/celica-data

[50] NASEO Annual Meeting, 2017. Panel Discussion on Energy Burden: Transportation, Mobility, and Housing Challenges for Low-Income Households. http://annualmeeting2017.naseo.org/agenda

[51] NRECA. Jun 2017. Business and Technology Advisory. Spotlight on Community Assistance Programs:
Meeting Core Community Needs Through Innovation Advancing Energy Access for All. https://www.cooperative.com/programs-services/bts/Documents/Advisories/Advisory-Advancing-Energy-Access-for-All-Introduction-June-2019.pdf

[52] NGA 2019 Governors' Advisors Energy Policy Institute. Panel and presentation. "Energy Efficiency's Role in Rural Prosperity." https://www.nga.org/wp-content/uploads/2019/06/2019-Energy-Policy-Institute-Agenda_SPEAKERS-Latest.pdf

[53] NCLC. Feb 2018. The Low-Income Home Energy Assistance Program (LIHEAP). A Safety Net That Saves Lives. https://www.nclc.org/issues/energy-utilities-a-communications/liheap-safety-net-saves-lives.html

Economy[54]; the National Cooperative Business Association[55]; the Environmental and Energy Study Institute[56]; the Environmental Defense Fund[57]; the Natural Resources Defense Council[58]; the Southern Alliance for Clean Energy[59]; the Center for Biological Diversity[60]; the NC Department of Environmental Quality[61]; the University of North Carolina[62]; Duke University[63];

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[54] ACEEE. Jun 2018. The High Cost of Energy in Rural America: Household Energy Burdens and Opportunities for Energy Efficiency. https://www.aceee.org/sites/default/files/publications/researchreports/u1806.pdf

[55] NRECA, NCBA and EESI. Jul 2019. Congressional Briefing: Equitable Solutions to Rural Energy Burdens. https://www.eesi.org/briefings/view/071619ruralenergy

[56] *Id.*

[57] EDF. Mar 2016. Blog: Transforming an Energy Burden into an Energy Opportunity. http://blogs.edf.org/energyexchange/2016/03/22/transforming-an-energy-burden-into-an-energy-opportunity/

[58] NRDC. Apr 2016. Blog: Study Highlights Energy Burden for Households and How Energy Efficiency Can Help. https://www.nrdc.org/experts/khalil-shahyd/study-highlights-energy-burden-households-and-how-energy-efficiency-can-help

[59] SACE. Apr 2018. Blog: Is TVA ignoring how a proposed new fee could put vulnerable customers at risk? https://cleanenergy.org/blog/is-tva-ignoring-how-a-proposed-new-fee-could-put-vulnerable-customers-at-risk/

[60] CBD and Appalachian Voices. Oct 2019. Legal Challenge Opposes Duke Energy's North Carolina Rate Hike: Big Increase Would Hurt Residents, Hamper Clean Energy Transition. https://biologicaldiversity.org/w/news/press-releases/legal-challenge-opposes-duke-energys-north-carolina-rate-hike-2019-10-17/

[61] NCDEQ. Oct 2019. North Carolina Clean Energy Plan, Supporting Document. Part 3: Electricity Rates and Energy Burden. https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/3.-Electricity-Rates-and-Energy-Burden-FINAL.pdf

[62] UNC. Convergence of Climate-Health-Vulnerabilities. "Energy Poverty." https://convergence.unc.edu/vulnerabilities/energy-poverty/

[63] Duke University's North Carolina Leadership Forum. 2017-2018 FINAL REPORT: How can North Carolina best meet the future energy needs of its residents and businesses? https://sites.duke.edu/nclf/files/2018/10/NCLF-Annual-Report-Web.pdf

the NC Housing Finance Authority[64]; the NC Housing Coalition[65]; the NC Justice Center[66]; the NC Sustainable Energy Association[67]; and, Appalachian Voices[68], among others.

The phrase "energy burden" is defined in many ways. Generally, it is defined as the share, or percent, of gross annual household income spent on household energy bills, including all costs for heating, cooling and other energy needs such as powering appliances and lighting. It does not include household transportation costs.

Numerous factors influence the measure of household energy burden, including but not limited to: (1) household income/poverty level; (2) energy efficiency of the building envelope, heating and cooling system and appliances; (3) energy costs/rates; (4) housing type; (5) household size (number of people living in the home); (6) supplemental energy needs to accommodate poor health or disabilities; (7) home ownership status; and, (8) consumer knowledge and behavior.

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64 NCHFA. Jan 2019. Rural Counties in North Carolina Experience Significant Energy Burden. https://www.nchfa.com/news/rural-counties-north-carolina-experience-significant-energy-burden

65 NCHC. Dec 2018. Housing Matters: Mapping Energy Burden. https://nchousing.org/housing-matters-mapping-energy-burden/

66 NCJC. Nov 2019. Paying for energy costs harder for families living in poverty. https://www.ncjustice.org/publications/paying-for-energy-costs-harder-for-families-living-in-poverty/

67 NCSEA. Energy Solutions Reserve Fund. https://energync.org/esrf/

68 AV. Jul 2018. Blog: The burden of rural home energy costs. http://appvoices.org/2018/07/25/the-burden-of-home-energy-costs-in-rural-appalachia/

There are also various terms and related definitions describing household energy burden. For instance, a report produced for the US Department of Health and Human Services ("DHHS") provides the following definitions[69]:

1) **Energy burden (gross).** The percentage of gross annual household income that is used to pay annual residential energy bills.
2) **Home energy burden.** The share or percentage of annual household income that is used to pay annual home heating and cooling expenditures.
3) **Net energy burden.** The household's energy burden after the receipt of LIHEAP fuel assistance.
4) **Residential energy burden.** The percentage of annual household income that is used to pay for all residential energy used in the home.

The DHHS study used what it describes as the "Absolute Value Approach" based on accepted metrics for "moderate shelter burden" and "severe shelter burden," as well as data on median residential energy costs for low-income households to calculate a "moderate residential energy burden," defined as equaling or exceeding 6.5 percent of gross household income, as well as a "high residential energy burden" defined as equaling or exceeding 10.9 percent of income.

69 APPRISE. See p. 2.

In April 2003, a team of researchers, together known as Fischer, Sheehan and Colton ("FSC") -- who developed an online database and resource that is updated annually with data on county-level household energy burdens for various poverty levels as well as on unaffordable energy costs -- created, using pretty much the same calculation as the DHHS study used to identify "moderate residential energy burden," a different measure – "affordable (energy) burden" – to assess household energy burden. Their calculation identified the threshold for "affordable home energy costs" as 6 percent of gross household income, and defined all home energy costs above that threshold as constituting a "home energy affordability gap."[70,71]

Q: DOES DEC ACCOUNT FOR AND/OR ADDRESS THE IMPACT OF ITS PROPOSED RATE INCREASE ON LOW-INCOME HOUSEHOLD ENERGY BURDENS?

A: No. While DEC does address impacts on low-income customers, nothing within DEC's application or associated materials specifically recognizes or accounts for household energy cost burdens or the impact of the Company's proposed rate increase on household energy burden.

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70 Fisher, Sheehan and Colton. Home Energy Affordability Gap: Definitions. http://www.homeenergyaffordabilitygap.com/01_whatIsHEAG2.html

71 For the purpose of this testimony, I analyze 2016 home energy burdens for low-income households to determine the number of such households that meet or exceed both the FSC "affordable burden" threshold of 6 percent – which closely resembles the DHHS threshold for "moderate residential energy burden" – as well as the DHHS "high residential energy burden" threshold of 10.9 percent. I then use that data as a baseline for comparing how DEC's proposed rate increase affects household energy burden, as well as the number of homes falling in the "high residential energy burden" category in 2021 and 2025.

As explained and responded to later in my testimony, DEC does recognize the fact that many low-income customers may have a hard time paying their electric bill, addresses the impact of the proposed rate increase and its BFC on low-income customers, proposes mitigating practices and procedures for helping low-income customers pay their bill, discusses possible programs and policies to be considered through a stakeholder process, and describes current programs and investments that help low-income customers.

However, when asked via discovery requests to provide information on the average and median energy burden of DEC's customers, the Company responded by stating that it "objects to the definition and use of the phrase 'energy burden.'"[72]. In a separate discovery request, DEC was asked to answer "affirm" or "deny" to the statements: (1) DEC considered energy burdens on households as part of calculating their rate increase, (2) DEC considered energy burdens on households as part of setting the return on equity, and (3) The proposed rate change increases the energy burden on North Carolina residents. DEC responded to all three of these statements with "neither affirm or deny," and again added the statement that "the Company objects to the use of the term 'energy burden'" and does not calculate "energy burden" as defined in "that question."[73,74]

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[72] DEC Response to Intervenors Request DR 2-15.

[73] DEC Response to Intervenors Request DR 2-16.

[74] The definition of energy burden offered was in discovery request DR-15, in which, for the purpose of the request, we defined energy burden as "a household's payment of electricity divided by a household's income." While that is not the specific definition used in this testimony – in which we use total energy costs – not just electricity – as the numerator, the

This explicit refusal to accept a broadly defined, broadly accepted and broadly researched concept (as detailed above) exhibits a potential lack of understanding as to how DEC's proposed rate increase impacts actual low-income households. To the extent to which this is true, it is unlikely that any low-income programs DEC currently offers or proposes in the future will have any measurable impact on reducing the real and pervasive problem of household energy burden facing DEC's low-income residential customers.

Q: BRIEFLY SUMMARIZE THE EXTENT OF THE PROBLEM OF ENERGY COST BURDENS FACING NORTH CAROLINA FAMILIES, ON AVERAGE, AND LOW-INCOME FAMILIES SPECIFICALLY.

A: Data from the US Department of Energy's ("USDOE") "Low-Income Energy Affordability" ("LEAD") Tool show that the average energy burden for all of North Carolina's 3.82 million households was approximately 3 percent in 2016 (the most recent year for which data are available).[75] However, there are more than 950,000 households across the state that fall under 150 percent of the Federal Poverty Level ("FPL"), which represents a quarter of all households in the state.[76]

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principle remains the same, and DEC's response in DR-15 was, specifically, "The Company objects to the definition and use of the phrase "energy burden." This is a strong indicator that DEC's primary objection is not with the specific definition used, but the actual use of the phrase "energy burden."

75 USDOE. Low-Income Energy Affordability Data (LEAD) Tool. Accessed Feb 2020. Query for "North Carolina," and view results for "Avg. Percent Income (%)" and "Housing Counts." https://openei.org/doe-opendata/dataset/celica-data

76 *Id.* Query for "North Carolina," filter for "0-100% FPL," "100-150% FPL," and view results for "Housing Counts."

The average energy burden for these households was 11 percent, meaning that the average household under 150 percent FPL can be categorized as experiencing a "high residential energy burden." The average annual household income for those low-income households was $1,674, with electricity costs accounting for approximately 82 percent of total home energy costs.[77] By comparison, the US average home energy burden for the < 150 percent FPL category in 2016 was also 11 percent, although nationally the electricity-cost-only burden is 8 percent,[78] while in North Carolina it was 9 percent.[79]

According to the NC Department of Environmental Quality, the average energy burden for low-income households ranges from an average of 33 percent for households with incomes under 50 percent FPL, to 10 percent for households falling between 125 and 150 percent FPL.[80]

Q: EXPLAIN HOW LOW-INCOME HOUSEHOLD ENERGY BURDENS WILL LIKELY CHANGE AS A RESULT OF DEC'S PROPOSED RATE INCREASE.

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77 USDOE. LEAD Tool. Accessed Feb 2020. *Id.* Query for "North Carolina," filter for "0-100% FPL," "100-150% FPL," and view results for "Avg. Percent Income" and "Avg. Annual Energy Cost." Also, generate a chart of "Avg. Annual Energy Cost." Average household income is calculated by dividing average annual energy cost by the average percent income. https://www.energy.gov/eere/slsc/maps/lead-tool

78 *Id.* Same query and charts generated for "United States" as for North Carolina.

79 USDOE. Low-Income Energy Affordability Data (LEAD) Tool. Accessed Feb 2020. Query for "North Carolina," and view results for "Avg. Percent Income (%)" and "Housing Counts." https://openei.org/doe-opendata/dataset/celica-data; *Id.* Query for "North Carolina," filter for "0-100% FPL," "100-150% FPL," and view results for "Housing Counts."

80 NCDEQ. Oct 2019. North Carolina Clean Energy Plan, Supporting Document. Part 3: Electricity Rates and Energy Burden. See p. 14. https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/3.-Electricity-Rates-and-Energy-Burden-FINAL.pdf

A: Virtually 100 percent of the low-income (less than 150 percent FPL) households served by DEC, representing approximately 20 percent of all DEC residential accounts **(see Table 7 below)**, already face "unaffordable" energy costs. Any additional increase in rates will only render such costs more unaffordable, straining financial resources and forcing households to face even more difficult decisions as to which household needs must be sacrificed in order to keep the lights on. As my analysis also shows **(see Table 8 below)**, DEC's proposed rate increase would move more than 70,000 more low-income households into the category of experiencing "high household energy burdens," with 10.9 percent or more of gross household income being spent on home energy costs.

For the purposes of this testimony, I use my analysis to detail trends in home energy costs, household energy burdens from 2016 to 2019 (the year following DEC's last rate case), from 2019 to 2021 (the first full year following the present rate case), from 2021 to 2025 (the last year of DEC's projected annual value for the proposed Excess Deferred Income Tax (EDIT-2) Rider), and overall changes between 2016 and 2025. The main focus of the analysis is to specifically illustrate the impacts over time of DEC's proposed rate increase for this rate case.

To that end, **Table 7** provides the results of my analysis for average household energy burden and the number of households exceeding the 6 percent unaffordability threshold as well as the 10.9 percent "high household energy burden" threshold for the years 2016, 2019, 2021 and 2021. Then, **Table 8** provides total and percent changes in the number of households falling in the

10.9 percent category for 2016-2019, 2019-2021, 2021-2025, and overall from 2016-2025.

Table 7: The change in average energy burden and number of households exceeding energy burden thresholds as a result of DEC's proposed rate increase, 2016-2025[81]

	2016	2019	2021	2025
Total households < 150% FPL	332,239	332,239	332,239	332,239
> 6 percent energy burden				
Number of households	332,239	332,239	332,239	332,239
% all low-income	100%	100%	100%	100%
% DEC residential accts	20%	19%	19%	19%
> 10.9 percent energy burden				
Number of households	138,048	140,973	198,117	209,162
% all low-income	42%	42%	60%	63%
% DEC residential accts	8.3%	8.1%	11.2%	12.0%
Average energy burden	**10.5%**	**10.5%**	**11.2%**	**11.4%**

The results presented in **Table 7** show the following:

1) Every single one of the estimated 332,000 low-income households (defined as households falling under 150 percent of FPL) served by DEC experienced an "unaffordable" energy cost burden of 6 percent or greater in 2016. That did not change as a result of the 2017-18 rate case, and is

[81] Note: The values for percent of DEC residential accounts are based on DEC's numbers provided through discovery which showed a total of 1,669,610 residential accounts in 2016 and 1,750,082 residential accounts in 2018. See DEC Response to CBD & AV DR 2-1. "DECNC Average Monthly Bills for Selected Scheduled from 2014 through 2018." Attachment "DEC CBD & AV DR 2-1.pdf." Given that numbers for 2019, 2021 and 2025 are not readily available, the 2018 value was used to calculate this percentage.

not likely to change in light of the present rate case given that rates and electric bills would increase as a result.

2) Low-income households account for approximately 20 percent of all residential households served by DEC (as well as approximately 17 percent of all electricity sales),[82] and as such represent a significant portion of DEC's residential business and bear a significant portion of the cost burden stemming from DEC's expenses.

3) Low-income households served by DEC that experienced a "high energy burden" of 10.9 percent or greater represented 8.3 percent of DEC's residential accounts in 2016, dropping to 8.1 percent in 2019 as the number of DEC residential accounts increased and rates fell as a result of the 2017-18 rate case.

4) DEC's current request for a rate increase would result in high energy burdened, low-income households accounting for 11.3 percent of residential accounts in 2021, with the value increasing to 12.0 percent by 2025 (lacking another rate case) as the value of the EDIT-2 refund declines as projected and the EDIT-1 Rider expires in August 2022. In other words, high energy burdened households constituted one out of every 12 households served by DEC in 2016 and again in 2019, but the

[82] This value was calculated by dividing total kWh use among low-income households served by DEC in 2016 – as estimated using data from USDOE's LEAD Tool – by DEC's total residential electricity sales in North Carolina in 2016, as reported on the federal Energy Information Administration's Form EIA-861, "Sales to Ultimate Customers." https://www.eia.gov/electricity/data/eia861/

present rate case, if approved as requested, would increase that to one out of every nine households by 2021, and one out of every eight households by 2025.[83]

5) Households with a "high energy burden" of 10.9 percent or greater accounted for 42 percent of all low-income households in both 2016 and 2019. Per my analysis, that will increase to 60 percent as a result of DEC's current proposal, and 63 percent by 2025 as a result of DEC's proposed rate increase, the decline of the EDIT-2 Rider value and the expiration of the EDIT-1 Rider in 2022.

6) The average household energy burden for all low-income households served by DEC remained essentially unchanged between 2016 and 2019, averaging approximately 10.5 percent of household income for both years, which is just under the 10.9 percent threshold for "high household energy burden." DEC's requested rate increase would result in an average energy burden of 11.2 percent in 2021 – thereby moving the average for all low-income DEC customers above the 10.9 percent threshold, and that would continue an upward trajectory, rising to 11.4

[83] These values were calculated by diving the number of "high energy burden" low-income households for each year of analysis – as estimated per my analysis – by the number of DEC residential accounts for each of those years as provided by DEC in DEC Response to Intervenors Request DR 2-1. "DECNC Average Monthly Bills for Selected Scheduled from 2014 through 2018." Attachment "DEC CBD & AV DR 2-1.pdf." Given that future counts for residential customers beyond 2018 are not available, it was assumed for the purposes of this analysis that the number of DEC residential accounts in 2019, 2021 and 2025 are the same as in 2018.

percent by 2025 as the EDIT-2 Rider value declines and EDIT-1 expires in 2022.

Table 8: Increase in households exceeding 10.9 percent energy burden through 2021 and 2025 as a result of DEC's proposed rate increase

	2016-2019	2019-2021	2021-2025	2016-2025 (Total)	Percent total 2019-2025
Number of households	2,926	57,143	11,045	71,114	96%
Percent increase	2.1%	40.5%	5.6%	51.5%	
Percent of all low-income households	0.9%	17.2%	3.3%	21.4%	

The results presented in **Table 8** show the following:

1) As shown in **Table 7**, the number of low-income households experiencing a high energy burden of 10.9 percent or greater was approximately 138,000 in 2016, increasing only slightly to 141,000 in 2019 (a 2 percent increase, or just over 2,900 households as shown in **Table 8**).

2) The values in **Table 8** show that the rates proposed in the present case, all other factors being equal, would shift another 57,100 households into that category by 2021, and another 11,000 more by 2025. As a result, by 2025, nearly two-thirds of all low-income households served by DEC will be characterized as experiencing a "high household energy burden."

3) Overall, between 2016 and 2025, nearly 71,000 low-income households served by DEC – representing 4.1 percent of all DEC

residential accounts, and 21.4 percent of all low-income households served by DEC – will have moved from the "unaffordable" energy burden category to the "high household energy burden" category within ten years.

4) ***The large majority (96 percent) of this shift would occur between 2019 and 2025 as a direct result of DEC's currently proposed rate increase, annual decline in the EDIT-2 Rider value, and expiration of the EDIT-1 Rider in 2022. This represents a 50 percent increase in the number of high energy burdened households over that six-year time frame from 2019 to 2025.***

5) While not shown in any of the tables, it is useful to note that, per my analysis, average household energy burdens among low-income households served by DEC in 2016 ranged from 6.4 percent to 16.1 percent, and averaged 10.5 percent. Values for 2019 were virtually equal to that of 2016. The present rate case, if approved as proposed, would increase those values to 7.0, 17.3 and 11.2 percent in 2021, respectively, and 7.1, 17.6 and 11.4 percent by 2025 as the value of the EDIT-2 Rider declines and the EDIT-1 Rider expires.

Related to energy burden is the increase in actual electricity bills for low-income households that would result from DEC's proposed rate case. **Table 9** provides results for how average annual electric bills were estimated to have changed from 2016 to 2019 as a result of the 2017-18 DEC rate case, as well as what the increase in those bills would be for 2021 and 2025 as a result of DEC's current request for a rate increase. As noted earlier, these values reflect the total bill, including the new energy charge based on the proposed rates, inclusive of all riders, as well as the BFC, REPS charge, and the sales and use tax. The increase in average electric bills from 2021-2025 reflect the declining value of the EDIT-2 Rider as well as the expiration of the EDIT-1 Rider in August 2022.

As shown in the table, the 2017 rate case, with its associated *decrease* in residential rates (but *increase* in the BFC), resulted in an increase of $8.65 in average annual electricity bills for low-income households served by DEC between 2016 and 2019 ($0.72 per month). However, the current proposed rate increase will increase annual electric bills for those households by $104.58 ($8.72 per month, an 8 percent increase) by 2021 (compared to 2019), and an additional $24.50 per year between 2021 and 2025. This represents a total increase of nearly $130 per year ($10.76 per month, a 9.9 percent increase) between 2019 and 2025 as a result of DEC's proposed rate increase.

Combined, if DEC's current request for a rate increase is approved, annual electric bills for low-income households will have increased by approximately $138 per year ($11.48 per month), on average, between 2016 and 2025 -- a 10.6 percent increase in a decade.

Given that the average monthly energy consumption for low-income households calculated for this testimony is 11,327 kWh per year (943.9 kWh per month) – which is just under the 1,000 kWh per month DEC highlights to illustrate the "average monthly bill impact" from the Company's proposed rate case, it is notable that the estimated bill increase for low-income households between 2019 and 2021 is 66 cents (or 8 percent) higher of an increase than DEC models for the average customer using 1,000 kWh per month, and – again, due to the projected decline in the EDIT-2 Rider and expiration of the EDIT-1 Rider in 2022 – the impact by 2025 is $2.70 per month (33 percent) higher than DEC's estimated average monthly bill impact for year 1.

Table 9: Increase in average annual electric bills for low-income households through 2021 and 2025 as a result of DEC's proposed rate increase

	2016-2019	2019-2021	2021-2025	2019-2025	2016-2025
Increase in annual electric bill	$8.65	$104.58	$24.48	$129.07	$137.72
Monthly average	$0.72	$8.72	$2.04	$10.76	$11.48
Percent increase	0.7%	8.0%	1.7%	9.9%	10.6%

Q: PLEASE DESCRIBE THE DATA SOURCES AND METHODOLOGY YOU USED TO ESTIMATE THE INCREASE IN ENERGY BURDEN.

A: To calculate the above results, I used "QGIS" GIS software to extract Census Tract-level data for households from the USDOE LEAD Tool for all tracts served by DEC, and extracted only the data for households falling under 150 percent FPL. This resulted in data collection for 853 Census Tracts, representing 332,239 total households that can be characterized as low-income households. Those households account for 8.7 percent of all households in the state, 34.9

percent of all households under 150 percent FPL,[84] and 20 percent of all DEC residential accounts in North Carolina.[85]

To establish an average 2016 baseline for median annual household income, annual household electricity costs, annual household gas costs, annual household costs for other fuels, total household energy costs, and average household energy burdens for all Census Tracts served by DEC, I calculated a weighted average of all factors (except for energy burden) for each Census Tract based on the total value for each factor divided by the total housing unit count for each Tract. I then divided the weighted average total energy cost by the weighted average annual household income to calculate an average low-income household energy burden for each Tract. I then did the same for all Tracts taken together to calculate an average household income, average household energy cost (total and broken out by energy source) and average energy burden for all low-income households served by DEC.

Finally, using the average electricity cost, combined with the net 2016 electricity rate (including all applicable riders at the time),[86] BFC and

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84 Calculated using data from USDOE's LEAD Tool. Query for "North Carolina," with and without filters for less than 150% FPL, and viewing results for "Housing Counts."

85 Calculated using data from Intervenors Request DR 2-1. "DECNC Average Monthly Bills for Selected Scheduled from 2014 through 2018." Attachment "DEC CBD & AV DR 2-1.pdf."

86 Base 2016 electricity rate for the residential RS schedule taken from DEC's Intervenors Response to DR 2-8. Attachment "DEC CBD & AV DR 2-8, RS." NC Forty-Second Revised Leaf No. 11, p. 1. Residential rate rider values applicable in 2016 taken from DEC's Intervenors Response to DR 2-5. Attachment "DEC CBD & AV DR 2-5_RiderValues." As rider values were revised twice following the initial effective date of January 1, 2016, for the purpose of this analysis I calculated a weighted-average rider value (based on the number of months each value was effective for) for each of the applicable riders

Renewable Energy Portfolio Standard tariff in place in 2016 for DEC customers,[87] and 7 percent sales and use tax for DEC customers on the residential RS rate schedule, I was able to calculate an average annual electricity usage (in kWh) for low-income households for each Census Tract and as an average across DEC's service area.

As shown in **Table 6** below, the average annual household income for low-income households served by DEC in 2016 was approximately $15,015, while the average total household energy cost was $1,574, resulting in an average household energy burden of 10.5 percent. Average total electricity costs (including fees and taxes) were approximately $1,302 ($1,058 for energy-only), and were associated with an average annual electricity consumption of 11,327 kWh.

Among the 834 Census Tracts, household incomes ranged from $7,055 to $23,051, total annual energy costs ranged from $695 to $1,894, household energy burdens ranged from 6.4 percent to 16.1 percent, and average annual electricity use ranged from 5,293 to 17,226 kWh (441 kWh and 1,436 kWh per month, respectively).

Table 6: Annual household incomes, energy costs, energy burdens and electricity consumption for low-income households served by DEC in 2016

	Avg. household income	Total energy cost	Electricity cost	Energy burden	Electricity use (kWh)

and applied that weighted average to the base rate to calculate an annual net rate for the residential RS rate schedule.

[87] DEC's Intervenors Response to DR 2-8. Attachment "DEC CBD & AV DR 2-8, RS."

Min.	$7,055	$751	$695	6.4%	5,293
Max.	$23,051	$2,246	$1,894	16.1%	17,226
Median	$15,221	$1,636	$1,300	10.5%	11,308
Mean	$15,015	$1,574	$1,302	10.5%	11,327

Consistent with statewide averages,[88] household electric bills accounted for 83 percent of total energy costs for low-income households served by DEC in 2016. *This indicates the degree to which changes in electricity prices (rates) affect total household energy costs, and therefore household energy burdens for low-income households.*

Additionally, and of significance for the present rate case, my analysis shows that virtually 100 percent of the 332,239 low-income households served by DEC in 2016 (again, representing approximately 20 percent of all DEC residential accounts and 17 percent of all residential electricity sales in that year) experienced an "unaffordable" energy cost burden of 6 percent or greater. Of those, approximately 138,000 households served by DEC that experienced a "high energy burden" of 10.9 percent or greater represented 42 percent of all low-income households served by DEC, and 8.3 percent of all DEC's residential accounts in 2016. ***These numbers show that low-income, energy burdened households represent a significant portion of DEC's residential business and bear a significant portion of the cost burden stemming from DEC's expenses.***

[88] USDOE Lead Tool. "North Carolina," chart for "Avg. Annual Energy Costs" and calculate the percent of total energy costs attributable to electricity costs.

Once I had a baseline established for each of the aforementioned factors, I was able to adjust the average household *base* electricity bill (not including fees or taxes) for low-income households within each Census Tract served by DEC, and for the whole of the low-income household population, by multiplying each of the Tract and service area values for the average annual household electricity consumption (in kWh) by the weighted average, net residential RS electricity rate[89] (in dollars-per-kilowatt-hour) in place in 2019. I then added the annual values for the BFC and Renewable Portfolio Standard ("REPS") tariff in place in 2019 to the base electricity charge, calculated the 7 percent sales and use tax for that total, then summed each of these charges together to calculate an average total electricity cost for each Tract and did the same for the service area as a whole.

To calculate the average total energy bill for each Tract and the service area for 2019, I then added the average annual costs for gas and other fuels that had been calculated by the USDOE's LEAD Tool for 2016 to the average total electricity cost. Dividing this new average total energy cost for 2019 by the

[89] Base 2019 electricity rate for the residential RS schedule taken from DEC's Intervenors Response to DR 2-8. Attachment "DEC CBD & AV DR 2-8, RS." NC Forty-Sixth Revised Leaf No. 11, p. 1. Residential rate rider values applicable in 2019 taken from DEC's Intervenors Response to DR 2-5. Attachment "DEC CBD & AV DR 2-5_RiderValues," NC 36th through 40th Revised Leaf No. 99. A weighted average value calculation was again necessary because, while the base rate did not change in 2019, there were multiple adjustments to the riders that applied to residential rate schedules. Therefore, the weighted average net electricity rate used for this analysis represents the base rate plus the weighted average value for each of the individual, applicable riders over the course of 2019.

average household income from 2016 generated the average household energy burdens for 2019.

I then used the same methodology to calculate base and total electricity costs, total energy costs, and average household energy burdens for 2021 and 2025. The net electricity rates used for the analysis for those two years are those presented in **Table 3**, and reflect the rates that households on the residential RS rate schedule will pay, net of all riders, in 2021 and 2025 as a result of DEC's proposed rate increase. The calculation again includes the BFC, REPS charge, and sales and use tax, which reflect the charges and tax rate in place in 2018.

Before proceeding, it is important to address the limitations faced in my analysis, given their impact on the results and conclusions presented in this testimony. First, due to the lack of available data on median household income for households falling under 150 percent FPL for any year after 2016, my analysis assumes no change in household income between 2016 and 2025. This impacts the results for average household energy burden and the number of homes exceeding the 10.9 percent "high household energy burden" threshold. While this would skew the results only slightly for 2019, it is likely that error would have a greater influence on the results for 2021 and 2025.

Second, again given the lack of available data beyond 2016, my analysis assumes no change in average household electricity use. Unlike with household income, where we can assume that some increase occurred after 2016, no such assumption can be made for average electricity use. If usage increased, then electricity and total energy costs would increase, thereby dampening any skewing of the results resulting from increases in household income. Conversely, if electricity use for low-income households served by DEC has declined, it would enhance the error in the results. Similarly, the analysis assumes no change in costs for gas or other fuels used for household heating and cooling needs. Again, without more recently available data, no conclusion can be drawn as to how changes in the cost of those fuels since 2016 may have impacted the results.

Third, the analysis necessarily assumes that no other changes in rates, fees or riders will occur by 2025 than are currently anticipated (such as the decline in the EDIT-2 Rider value and the expiration of the EDIT-1 Rider). This does not pose a foreseeable risk for the 2021 analysis and results, but could affect the results for 2025 if another rate case or adjustment to any of the applicable riders does occur before then.

Fourth, it is notable that various other factors could influence the results over time. Changes in household size (the number of people occupying a household) could affect values for both household income and electricity use. The aging of the housing stock, heating and cooling systems and appliances over time could result in lower overall energy efficiency and thus higher electricity usage.

Finally, the analysis was only conducted using past and proposed rates for the residential RS rate schedule, which creates the inherent assumption that 100 percent of all low-income households are on DEC's RS rate schedule and not the RE or any other schedule. This is not likely to be the case, but the RS schedule, given its straightforward and simple rate structure, was easy to model, whereas the RE schedule, with its seasonal and tiered energy rates, would have required a far more complicated model and would have produced results with a much greater margin of error. Additionally, it is not possible to parse out which data in the LEAD database are for customers on different rate schedules.

Regarding this last assumption, it is useful to note that approximately 60 percent of all residential customers served by DEC were on the RS rate schedule as recently as 2018.[90] Additionally, and perhaps more importantly, not a single Census Tract had an average cost for gas or other non-electric fuels of $0 for 2016, and only 14 percent of all Tracts analyzed had an average household gas cost less than $100 per month (which represents approximately half of the average gas cost for all households). In other words, while 40 percent of all DEC residential customers may be on the RE rate schedule, the requirements for households to be eligible for the RE "all electric" rate schedule,[91] combined with the USDOE data on fuel costs for low-income households served by DEC suggests that the large majority of households represented in my analysis are on DEC's residential RS rate schedule.

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90 DEC Response to CBD & AV DR 2-1. "DECNC Average Monthly Bills for Selected Scheduled from 2014 through 2018." Attachment "DEC CBD & AV DR 2-1.pdf"

91 Intervenors Response to DR 2-8. Attachment "DEC CBD & AV DR 2-8, RE." NC Forty-Eighth Revised Leaf No. 13, p. 1. As described in DEC's residential RE rate schedule, for a household to be eligible for this rate schedule, "all energy required for all water heating, cooking, clothes drying, and environmental space conditioning must be supplied electrically."

Despite these assumptions, the analysis conducted in support of this testimony and the results presented herein offer the best (and only) available representation of how DEC's proposed rate increase will impact low-income households in 2021 and beyond. If more recent data become available during the course of this rate case, the analysis may be adjusted and new findings presented. Regardless, this analysis provides a more detailed, accurate and relevant representation of the ability (or lack thereof) of low-income households ("customers") to afford DEC's proposed rate increase.

Q: WHAT PROGRAMS DOES DEC CURRENTLY OFFER OR IS PROPOSING IN THE PRESENT RATE CASE THAT HELP REDUCE THE BURDEN OF ENERGY COSTS FOR LOW-INCOME HOUSEHOLDS?

A: First, as mentioned earlier in my testimony, DEC, via discovery, has objected to "the definition and use of the phrase energy burden."[92,93] As such, the Company's programs do not necessarily aim to reduce household energy cost burdens. However, DEC does recognize that low-income customers might struggle to pay their electric bills and pay for other basic needs "during times of financial hardship,"[94] and has developed some policies and programs that help address that problem. As described by Witness De May, these include:

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[92] DEC Response to Intervenors Request DR 2-15.

[93] DEC Response to Intervenors Request DR 2-16.

[94] Direct testimony of Stephen G. De May for Duke Energy Carolinas, LLC. Docket No. E-7, Sub 1124. Page 8. https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=146284ce-2d8c-4b74-842e-f9409f52e32c

1) the Share the Warmth program – a ratepayer donation-based program that helps eligible low-income households pay unaffordable heating bills in the winter months, with DEC matching ratepayer contributions up to $500,000; and,

2) DEC's portfolio of demand-side management ("DSM") and energy efficiency ("EE") programs, which includes the Neighborhood Energy Saver Program.[95]

Additionally, with the aim of doing "even more for these customers, particularly those most in need," in the present rate case DEC is:

1) proposing a lower-than-recommended return on equity "as a rate mitigation measure";

2) not requesting an increase in the BFC, "even though an increase is warranted," so that the Company can work with stakeholders to identify other opportunities for helping low-income customers through rate design;

3) reducing the amount of executive compensation DEC is seeking to recover, as a cost-mitigation measure; and,

4) proposing to eliminate credit card fees for residential customers who pay their bills with a credit card.[96]

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[95] *Id.*

[96] *Id.* at p. 8-9.

Finally, Witness De May shares other ideas DEC has identified as possible low-income programs and rate structures the Company could offer in the future, including:

1) a low-income bill credit on the BFC for qualifying low-income customers;
2) a bill "Round-Up" program allowing customers to round their monthly bills up to the nearest dollar to help fund bill payment assistance programs through organizations/foundations that offer those services;
3) expanding and re-tooling the Supplemental Security Income price discount (currently capped at $2.92 per month) for customers who receive SSI; and,
4) other new low-income programs identified through a Commission-ordered stakeholder process.[97]

Q: WHAT IS YOUR RESPONSE TO DEC'S EXISTING AND PROPOSED POLICIES AND PROGRAMS INTENDED TO BENEFIT LOW-INCOME HOUSEHOLDS?

A: In relation to their existing programs, I conclude that, while these programs are important and represent a good start, they do very little to help reduce the burden of energy costs for the large majority of low-income customers served by DEC, nor do they do much to address one of the most significant underlying factors

[97] *Id.* at p. 9-10.

leading to high energy costs: the lack of energy efficient homes, heating and cooling systems and appliances.

Specifically, the Share the Warmth program, while critical and helpful to households that are unable to afford their winter heating bills, caps DEC's contribution at $500,000, presumably annually.[98]

For the sake of putting that amount in context, $500,000 represents only 0.54 percent of the total funding directed to North Carolina from the federal Low-Income Home Energy Assistance Program ("LIHEAP allocated in Federal Fiscal Year ("FFY") 2019[99] – a program for which the majority of funds are used for the same bill assistance purpose as DEC's Share the Warmth program. Data for the NC LIHEAP grant for FFY 2018, combined with NC's DHHS's plan for FY 2020 showing that approximately 75 percent of all LIHEAP funding goes directly to assist households,[100] indicates that the average per-home allocation of LIHEAP heating and crisis assistance funds during that time period was approximately $350. At this level of funding, it can be estimated that DEC's maximum contribution to Share the Warmth helps only about 1,500 households a year. While that is significant for those individual households, 1,500

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98 Duke Energy. Customer Assistance Programs, Share the Warmth. https://www.duke-energy.com/community/customer-assistance-programs/share-the-warmth

99 NC DHHS. North Carolina Weatherization Waver FFY 2019. https://files.nc.gov/ncdhhs/documents/files/dss/publicnotices/Weatherization-Waiver-FFY2019.pdf

100 NC DHHS. Low-Income Home Energy Assistance Program, Detailed Model Plan, FFY 2020. https://files.nc.gov/ncdhhs/documents/files/dss/publicnotices/FFY-2020-LIHEAP-Block-Grant-Plan---Detailed-Model-Plan.pdf

households represent only 1 percent of the "high energy burden" households I estimate to have been served by DEC in 2019.

In relation to DEC's DSM/EE programs, only the Neighborhood Energy Saver Program and DEC's Low-Income Weatherization Program directly reduce energy bills, and thus energy burdens for low-income households. Again, while these are critical and necessary programs, they only scratch the surface in addressing the scale of the problem.

For instance, the Low-Income Weatherization Program – which invests in higher-impact home energy improvements such as insulation, air sealing and appliance upgrades – helped only 3,782 homes between 2015 and 2019, representing 2.7 percent of all high energy burdened households and 1.1 percent of all low-income households served by DEC.[101] The Neighborhood Energy Saver Program, while reaching more than 40,000 more households over the same time period, only offers minor improvements such as energy efficient light bulbs, water savings, low-flow shower heads and faucet aerators, water heater insulation, weather stripping and other similar items.[102] While these items do help lower energy costs, they do not address the more substantial energy issues that result in the greatest energy waste, and thus high energy burdens.

Relating to DEC's proposed rate mitigation measures, the proposal of a lower-than-recommended ROE does result in a lower rate increase, but the claim

[101] DEC Response to Interventors DR-2-10.
[102] Duke Energy. Neighborhood Energy Saver Program flyer. https://www.duke-energy.com/_/media/pdfs/for-your-home/nes-program-flyer.pdf?la=en

that this is a rate mitigation measure is questionable given that the requested 10.3 percent ROE is still 0.4 percent higher than DEC's currently-approved ROE of 9.9 percent, and it is yet to be determined whether even a 10.3 percent ROE is justified – especially in light of the fact that DEC Witness Hevert's recommendation for a 10.75 percent ROE for Virginia Electric and Power Company (Dominion Energy Virginia) in Virginia was strongly rejected in November 2019 by the Virginia State Corporation Commission, which approved a far smaller ROE of 9.2 percent.[103] This calls into question DEC's claim that the lower-than-recommended (by Witness Hevert) ROE of 10.3 percent is a rate mitigation measure. [104]

A similar argument could be made in relation to DEC not proposing an increase in its BFC given that the Company has indicated that it intends to propose an increase in the charge in a future rate case. In reality, the lack of a request in the BFC for the present rate case seems more like a response to the rejection of a similar increase in the BFC DEC requested in South Carolina in 2019.[105] In a Commission Directive preceding the order for that case, the Public Service Commission of South Carolina stated that DEC's request for an increase in its residential BFC from $8.29 to $28 demonstrated that DEC was ""tone

[103] Commonwealth of Virginia State Corporation Commission. Final Order. Case No. PUR-2019-00050, "For the determination of the fair rate of return on common equity." Nov 21, 2019. http://www.scc.virginia.gov/docketsearch/DOCS/4jx901!.PDF

[104] Hevert Testimony at p. 4.

[105] Public Service Commission of South Carolina. Commission Directive. Docket No. 2018-319-E. May 1, 2019. Page 1. https://dms.psc.sc.gov/Attachments/Matter/86a4fa07-3796-4ff7-8486-07de716a0809.

deaf" as to how a 238% increase in the Basic Facilities Charge would have negatively and adversely impacted the elderly, the disabled, the low income and low use customers."[106] DEC later agreed to lower the BFC request to $11.96 for residential customers.[107]

By comparison, DEC's 2017-18 rate case in North Carolina increased the BFC to $14.00.[108] If the decision not to propose another increase in the BFC was indeed in consideration of how a higher BFC could impact low-income households, they might have considered actually lowering the BFC to the level approved for DEC in South Carolina. It is not necessary to detail how this story played out in a similar manner in the same South Carolina rate case in relation to executive compensation except to say that the Commission also applied the "tone deaf" criticism in rejecting the large majority of DEC's request to recover executive compensation.

Finally, eliminating credit card fees for residential customers who pay their bill with a credit card is also helpful, but long overdue. It is common sense that most customers who pay electric bills with a credit card do so because they lack sufficient income at the time of the due date to cover the cost of the electric bill. Thus, they are likely to be low-income households.

As for DEC's ideas for future low-income programs and developing a stakeholder process, this is also a good indication that DEC may do more to

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[106] *Id.*
[107] *Id.*
[108] Intervenors Response to DR 2-8. Attachment "DEC CBD & AV DR 2-8, RS." NC Forty-Sixth Revised Leaf No. 11, p. 1.

address low-income household energy burdens in the future. However, instead of responding to long-standing proposals by social and environmental advocates put forth through the Duke Energy Collaborative process[109,110] – such as the proposal that DEC develop a tariffed on-bill energy efficiency finance program accessible to all customers regardless of income, credit score or home ownership – and proposing the development of some of those proposals through the present rate case, DEC is delaying any new programs that could begin to meet the scale of the energy burden problem until yet another stakeholder process is conducted.

Overall, DEC's existing programs that help low-income households pay their heating bill and offer funding for weatherization and other home energy efficiency improvements are important and critical to the individuals and families that receive that assistance. But, especially in light of the impact that the present rate case will have on deepening the problem of household energy burdens experienced by low-income households served by DEC, the Company should be doing and investing far more than they currently are in addressing that problem, and they are missing the opportunity to do so in the present rate case.

Q: HOW WOULD THE LOW-INCOME ENERGY BURDEN BE LOWERED IF THE COMMISSION CONSIDERED AND APPROVED A LOWER RETURN ON EQUITY THAN DEC IS REQUESTING?

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109 Southern Alliance for Clean Energy. May 2015. On-Bill Financing Program Recommendation Overview for Duke Energy Carolinas.

110 Advanced Energy. December 2016. Report (for DEC): Residential EE Retrofit Programs Market Research.

A: Through my analysis, it appears that electricity bills, and by extension household energy burdens, could be lowered from the levels I have projected to result from DEC's proposed rate increase if the Commission approved a lower return on equity than DEC's proposed 10.3 percent ROE.

I have analyzed what the resulting revenue increase would be at different ROE levels using data provided by DEC Witness Pirro, and the results may serve as a proxy for how electricity bills, and by extension household energy burdens, could be lowered from the levels I have projected to result from DEC's proposed rate increase.

According to DEC Witness Pirro, DEC's proposed 10.3 ROE, based on a 53 percent equity, 47 percent debt capital structure, would require a gross increase in annual residential revenues of $238,588,158, for a 10.25 percent increase in total revenues (including all present rider revenue). This represents 52 percent of DEC's total proposed revenue increase. Accounting for the first-year EDIT-2 refund value ($80,148,603) for the residential class, the net revenue increase would be $158,439,556, for a net increase of 6.8 percent for the residential class. [111]

Using Witness Pirro's data, I adjusted the revenue requirement for ROE's of 9.9 percent (DEC's currently approved ROE) and 9.2 percent (the ROE approved for Dominion Energy Virginia in November 2019), and also 9.2

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[111] Pirro Testimony, ex. 2 at p. 1-2.

percent at DEC's current 52/48 capital structure (rather than the 53/47 ratio they are proposing, which I maintained in the analysis for the first two ROE's).

As shown in **Table 10**, using the same calculation as presented in DEC's application,[112] applying a 9.9 percent ROE (and maintaining the requested 47/53 debt-to-equity ratio) would reduce the residential revenue increase by 7.2 percent, saving residents $17.1 million, and lower the gross (no EDIT-2) percent increase in rate revenues (DEC's representation of "rate increase") from 10.25 percent to 9.5 percent. Including the EDIT-2 (first-year) refund would lower the rate increase from 6.8 percent to 6.1 percent.

Accordingly, approving a 9.2 percent ROE would result in a 19.7 percent decrease in revenues, saving residents approximately $47.1 million, and resulting in a gross rate increase of 8.2 percent (2 percent lower than what DEC is proposing), and a net increase of 4.8 percent. Finally, a 9.2 percent ROE combined with maintaining DEC's current 52/48 capital structure would lower the revenue increase by 21.3 percent, saving residents $50.8 million, resulting in a gross rate increase of 8.1 percent and a net increase of 4.6 percent in the first year. It is important to note that as the annual value of the EDIT-2 refund declines in year 2 and beyond, the net rate increase will go up, eventually approaching the gross percent rate increase value.

Table 10: Revenue and rate increase (and savings) at different ROE's

[112] Duke Energy Carolinas, LLC. Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets. Docket No. E-7, Sub 1214. Exhibit C, p. 2. Sept. 30, 2019.

Return on Equity	Gross rev. increase ($M)	Savings ($M)	Percent change	Gross rate increase	EDIT-2 refund ($M)	Net rev. increase ($M)	Net rate increase
10.3% ROE	$238.6	$0.0	0%	10.3%	$80.1	$158.4	6.8%
9.9% ROE	$221.5	-$17.1	-7.2%	9.5%	$80.1	$141.3	6.1%
9.2% ROE	$191.5	-$47.1	-19.7%	8.2%	$80.1	$111.4	4.8%
9.2% ROE, 52% Equity	$187.7	-$50.8	-21.3%	8.1%	$80.1	$107.6	4.6%

As noted, converting the savings values and rate increase percentages for different ROE's as shown in **Table 10** is beyond my expertise. However, within the context of how DEC's proposed rate increase and ROE would significantly increase household energy burdens for its low-income customers, it is clear that rejecting DEC's proposed ROE and even lowering it from current levels would save residential customers a substantial amount of money – strictly from adjusting these two factors, as a consideration of costs DEC is proposing to recover is of equal importance.

For illustrative purposes, however, it is notable that spreading the $50.8 million in savings for the 9.2 percent ROE/52 percent equity scenario equally among all 1.75 million of DEC's residential customers would save the average customer $29 a year ($2.40 a month), thus reducing the first-year bill impact for the average customer using 1,000 kWh a month (as calculated by DEC) by 30 percent.

<u>IV. REVISING HOW THE COMMISSION CONSIDERS "CHANGING ECONOMIC CONDITIONS" AND "CUSTOMER ABILITY TO AFFORD A RATE INCREASE" AS INCLUDING ENERGY BURDEN CONSIDERATIONS</u>

Q: PLEASE BRIEFLY EXPLAIN THE MANNER IN WHICH THE COMMISSION IS REQUIRED TO CONSIDER THE IMPACTS OF A RATE INCREASE ON RATEPAYERS.

A: As explained in the Proposed Order of the Public Staff for the 2017-18 DEC rate case: "the Commission must . . . make findings of fact regarding the impact of *changing economic conditions* on customers when determining the proper rate of return on equity for a public utility."[113]

Moreover, relating to customers' ability to afford a rate increase,

> [C]hanging economic circumstances as they impact . . . customers may affect those customers' ability to afford rate increases. For this reason, customer impact weighs heavily in the overall rate setting process, including . . . the Commission's own decision of an appropriate authorized rate of return on equity.[114]

In other words, in considering a public utility's request for a rate increase and associated ROE, the Commission is required to weigh "changing economic conditions" as they affect "customers' ability to afford rate increases." Of course, these considerations must be balanced with the utility's ability to compete for and procure capital, but it is notable that customer impacts should "weigh heavily" in the rate setting process.[115]

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[113] State of North Carolina Utilities Commission, Proposed Order of the Public Staff. "In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina" (April 27, 2018), p. 80. Docket Nos. E-7, sub 819, 1110, 1152, 1146 (emphasis added).

[114] *Id*. at 84.

[115] *Id*.

This testimony argues that the economic conditions which have been considered in past rate cases are insufficient for properly assessing how the ability of a large portion of the residential customer class in North Carolina – those households earning less than 150 percent of FPL – to afford a proposed rate increase is affected.

Q: WHAT FACTORS HAVE DEC AND THE COMMISSION CONSIDERED IN PAST RATE CASES AND THE PRESENT RATE CASE TO ASSESS "CHANGING ECONOMIC CONDITIONS" AND "CUSTOMER ABILITY TO AFFORD A RATE INCREASE"?

A: In DEC Witness Hevert's testimonies for the 2017-18 DEC rate case and for the present rate case, he assesses "changing economic conditions" based on national and state trends in Gross Domestic Product, unemployment, median household income, personal income and consumption and electricity rates.[116,117] In the 2017-18 rate case, Public Staff witness Parcell went even further by examining county-level indicators, including unemployment rates, absolute employment, real taxable retail sales, and trends in residential building permits and job postings.[118] These represent more direct measures of changing economic conditions on more of a community scale than do the statewide and national measures examined by Witness Hevert.

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116 *Id.* at p. 113-114.

117 Hevert Testimony at p. 54-62.

118 State of North Carolina Utilities Commission, Proposed Order of the Public Staff. "In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina" (April 27, 2018), p. 114-115. Docket Nos. E-7, sub 819, 1110, 1152, 1146 (emphasis added).

Q: WHAT IS YOUR RESPONSE TO HOW THE COMMISSION AND DEC HAVE CONSIDERED THESE FACTORS IN THE PAST?

A: While the requirement for the Commission to consider the factors of "changing economic conditions" and "customer ability to afford a rate increase" is necessary and appropriate, what appears clear from the reading of the 2018 Order is that there has been no attempt to directly quantify, in any manner, "customer ability to afford a rate increase," which logically seems to be more of a microeconomic calculation than a macroeconomic one.[119] As such, identifying and considering "customer ability to afford a rate increase" lends itself more to a calculation of household energy costs and average household energy burdens – especially for low-income households, and especially if those households constitute a significant proportion of the general body or ratepayers – than it does macroeconomic measures. Unfortunately, it appears that only macroeconomic measures have been considered in past rate cases.

Further, regarding "changing economic conditions," I believe that rate increases, and resulting increases in electricity bills themselves reflect a "changing economic condition." Electricity bills are a cost (most) households must pay to experience a normal and dignified quality of life, and they are one of many such costs. Rising costs, whether via inflation or as the result of a regulator-approved rate increase, reflect a changing economic condition

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[119] State of North Carolina Utilities Commission, Proposed Order of the Public Staff. "In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina" (April 27, 2018), p. 80. Docket Nos. E-7, sub 819, 1110, 1152, 1146 (emphasis added).

households face, much as lost income due to unemployment or an increase in borrowing may occur during an economic downturn.

As such, rising electricity costs should added to the factors considered in this and future rate cases, especially because they have a direct impact on customer ability to afford another rate increase. Otherwise, eventually – and this is especially true in light of DEC's plan to spend billions of dollars over the next decade on coal ash cleanup and grid improvement – electricity costs will rise to a level of unaffordability for low-income households to where they severely cut back on their electricity use, which will negatively impact quality of life and could put the health and lives of individuals at risk.

Q: HAVE OTHER JURISDICTIONS CONSIDERED ENERGY BURDEN IN THEIR RATE CASES?

A: Yes, in both similar and different contexts. For instance, the California Public Utilities Commission issued an Order in 2018 to assess the impacts on affordability of individual CPUC proceedings and utility rate requests. In addressing energy burden in that order, the CPUC stated:

> "Part of the challenge in defining and measuring 'affordability' is determining the appropriate scale and targeted threshold. For example, **energy burden**, or the ratio of the median cost of a service to the medium income, is one of the simplest metrics used to evaluate affordability today; however, an evaluation of energy burden will have very different results if conducted on a statewide vs. local regional level,

> while the results themselves may have different meanings to different people."[120]

And in 2015, the CPUC issued another Order aimed at reviewing residential rate structures more generally, again with a consideration of household energy burden and affordability, stating that:

> "We continue to employ the **energy burden** metric as an assessment of the general affordability of the rate design reforms. While we do not specifically hold that a 5% mark is the appropriate threshold for determining affordability, we continue to use it as a guideline for examining the impacts of rate reform on the affordability of energy."[121]

Additionally, in the context of reviewing and revising low-income utility programs, the New York Public Utilities Commission ("NYPUC") stated that:

> "**Energy burden** at or below 6% of household income shall be the target level for all 2.3 million low income households in NY." [NY PUC] "adopts a goal of reducing household energy burden to 6% of household income for all low income utility customers. Approximately 2.3 million New York State households face energy burdens in excess of that level."[122]

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[120] CPUC. *Order Instituting Rulemaking* (R.18-07-006). July 12, 2018. Emphasis added.

[121] CPUC. Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations. 3015 California PUC LEXIS 43. July 3, 2015. Emphasis added.

[122] NYPUC. Order Adopting Low Income Program Modifications and Directing Utility Filings, Case 14-M-0565. NYPUC LEXIS 267. May 20, 2016. Emphasis added.

And in Pennsylvania, in response to an order that directs the Pennsylvania PUC staff to initiate a study "to determine what constitutes an affordable **energy burden** for PA's low-income households and, based on this analysis, whether any changes" to Energy Conservation Programs are necessary, the PA PUC observed, in part that:

> "Pennsylvania's maximum **energy burdens** in the CAP Policy Statement (5-17%, depending on the energy status, fuel source, and FPIG) were generally higher than maximum energy burdens in neighboring states. Ohio's utility payment assistance program has a maximum energy burden of 10%. New Jersey's utility payment assistance program has a maximum energy burden of 6% for total electric and for combined gas and electric. The maximum energy burden for New York's payment assistance program is 6% for gas and electric service."

And, as it relates to and provides precedent for one of my key recommendations in this testimony, the PA PUC ordered that: "Utilities shall…provide cost forecasts [for customers] based on a 10% maximum energy burden for 2017 through 2021."[123]

Additional examples exist from Kentucky, New Jersey, Arkansas and Ohio of regulatory commissions addressing energy burden and household energy cost affordability in relation to low-income programs.

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[123] 2019 PA PUC LEXIS 32. January 17, 2019.

Q: HOW WOULD YOU RECOMMEND THAT "CHANGING ECONOMIC CONDITIONS" AND "CUSTOMER ABILITY TO AFFORD A RATE INCREASE" BE CONSIDERED IN THE PRESENT AND FUTURE RATE CASES?

A: My recommendation is that DEC and the Commission estimate, consider, and give primary weight to the impact that a rate increase and associated ROE, as well as any increase in the BFC, will have on electricity costs and household energy burdens low-income households face. This is now quantifiable as I have presented in my testimony, and it is clear that DEC's proposed rate increase will have severe negative consequences for the 332,000 low-income households served by DEC, virtually every one of which already experiences unaffordable annual energy costs in excess of 6 percent of their gross household income, and more than 40 percent of which are already categorized as having a "high household energy burden" in excess of 10.9 percent of their annual income. This is a problem that needs to get better before it gets worse, and DEC's proposal will render it much worse.

<u>V.</u> <u>RECOMMENDATIONS</u>

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR THE COMMISSION.

A: My recommendations for the Commission are as follows:

1) Given that it is more accurate and transparent to represent a rate increase as the "percent increase in rates" for customers on different rate schedules rather than as a "percent increase in residential rate

revenues," I recommend that the Commission require all public utilities, including DEC in the present rate case, to prominently represent in their initial application and related filings the gross and net rate impacts for individual rate schedules that show what the actual percent change in "rates" – in cents per kWh – that customers on those individual rate schedules will experience. This should be required as a gross percent change in the base rate, as well as the net percent change inclusive of all riders.

2) Given that impacts on customer electricity bills could potentially be higher (or lower) than estimated for the first year following a given rate case, I recommend that the Commission require all public utilities, including DEC in the present rate case, to project and describe future rate and bill impacts – extending out to a minimum of five years – for customers on each individual rate schedule that accounts for any and all changes, whether known or estimated, in all applicable riders and fees over the time period of analysis. For example, in the present rate case, the Commission should require DEC to project and describe future rate and bill impacts for all rate schedules that account for the estimated annual decline in the value of the annual EDIT-2 tax refund – as it will necessarily result in an annual decline in the per-kWh EDIT-2 Rider value – as well as the expiration of the EDIT-1 Rider in August 2022.

3) The increase in residential electric bills through the present case, in the first year and over the following four years, must not only be

considered by itself, but also within the context of DEC's intention to shift more costs onto the residential class while also increasing the monthly BFC. In this regard, I recommend that the Commission consider all of these factors, especially in light of its mandate to consider "changing economic conditions" and "customers' ability to afford rate increases."

4) Given DEC's stated intention to shift more of its costs onto residential customers, through both the present and future rate cases, should itself be considered a "changing economic condition." This is especially true given the impact of that intention on "customers' ability to afford rate increases." Lacking an equal percent shift in household income -- not only on average, but specifically and especially for those with household incomes that fall below 150 percent FPL – higher electric bills *now* impair the ability of customers to afford *future* rate increases.

5) In its consideration of "changing economic conditions" and "customers' ability to afford a rate increase" in reviewing DEC's proposed rate increase and ROE, I recommend that the Commission estimate, consider, and give primary weight to the impact that a rate increase and associated ROE, as well as any future increase in the BFC, will have on electricity costs and household energy burdens low-income households face. While macroeconomic indicators such as GDP, unemployment, etc. serve as useful indicators of "changing economic conditions" on a state level, household energy burden

represents the most direct measure of "customers' ability to afford a rate increase," and the impact of a proposed rate increase and ROE on household energy burden is now quantifiable as I have presented in my testimony.

6) That the Commission require DEC to take household energy burden into account as part of the Company's assessment of trends in "changing economic conditions" in North Carolina and the application of that assessment to calculating and proposing its rate increase and ROE.

7) That the Commission strongly examine all costs for which DEC is proposing to recover in the present rate case through a lens of whether DEC's justification of those costs is sufficient to warrant enhancing the real and significant burden of energy costs on low-income households served by DEC.

8) That the Commission, in order to mitigate the impact of the Company's proposal on low-income households, reject DEC's proposal for a 10.3 percent ROE, and instead approve a ROE of no greater than 9.2 percent, which is the ROE recently approved by the Virginia State Corporation Commission ("SCC") for Dominion Energy Virginia ("Dominion")[124],

[124] Commonwealth of Virginia State Corporation Commission. Final Order. Case No. PUR-2019-00050, "For the determination of the fair rate of return on common equity." Nov 21, 2019. http://www.scc.virginia.gov/docketsearch/DOCS/4jx901!.PDF

and maintain DEC's current capital structure of 52 percent equity and 48 percent debt.

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR DEC.

A: In addition to accepting and adopting the practices detailed in my recommendations to the Commission, my final recommendation for DEC is as follows:

1) That DEC recognize and accept the definition and use of the phrase "energy burden," and make a more concerted and immediate effort to invest in low-income energy efficiency and demand-side management programs at a scale of investment sufficient to meet the scale of the energy problem among its low-income customers.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes, it does.

MS. DOWNEY: Madam Chair, Diana Downey for the Public Staff.

CHAIR MITCHELL: Ms. Downey, you may proceed.

MS. DOWNEY: We have three witnesses who were excused from this hearing. I will need to ask you about Mr. Metz. He filed testimony yesterday. We can address that at a later time. But with respect to Roxie McCullar, who was excused by the Commission's Order of August 31st, we would move into evidence her testimony and exhibits filed February 18, 2020, consisting of 35 pages and eight exhibits, which includes some confidential testimony and exhibits, and her supplemental testimony filed March 25, 2020, consisting of four pages and Appendix A.

CHAIR MITCHELL: All right. Hearing no objection, Ms. Downey, that motion is allowed.

(Whereupon, the prefiled testimony and prefiled supplemental testimony and Appendix A of Roxie McCullar was copied into the record as if given orally from the stand.)

(Whereupon, Exhibits RMM-1 through RMM-8 were admitted into evidence. RMM-1, RMM-2, and RMM-7 were filed under seal.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213 In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-7, SUB 1214 In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)	TESTIMONY OF ROXIE MCCULLAR ON BEHALF OF PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

Testimony of Roxie McCullar

On Behalf of the Public Staff

North Carolina Utilities Commission

February 18, 2020

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roxie McCullar. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. Since 1997, I have been employed as a consultant with the firm of William Dunkel and Associates and have regularly provided consulting services in regulatory proceedings throughout the country.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have 20 years of experience consulting in regulatory rate cases and have addressed depreciation rate issues in numerous jurisdictions nationwide. I am a Certified Public Accountant licensed in the state of Illinois. I am a Certified Depreciation Professional through the Society of Depreciation Professionals. I received my Master of Arts degree in Accounting from the University of Illinois in Springfield. I received my Bachelor of Science degree in Mathematics from Illinois State University in Normal.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DESCRIBES YOUR QUALIFICATIONS?

A. Yes. My qualifications and previous experiences are shown in the attached Appendix A.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Public Staff of the North Carolina Utilities Commission ("Public Staff").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the depreciation rates proposed to be used by Duke Energy Carolinas, LLC ("DEC" or "Company") in North Carolina. On September 30, 2019, DEC witness John Spanos filed direct testimony in this proceeding supporting DEC's proposed depreciation rates, based on the "2018 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2018" that was included as Spanos Exhibit 1 ("2018 Depreciation Study").

Q. DID YOU PARTICIPATE IN A FIELD VISIT OF DEC'S FACILITIES IN NORTH CAROLINA?

A. Yes. During my review of the depreciation study utilized in DEC's prior rate case in Docket No. E-7, Sub 1146 ("Sub 1146 Proceeding"), I participated in field visits of several different DEC facilities or project locations on December 11-13, 2017.[1] At each location, Company personnel or outside contractors discussed the facilities and ongoing projects with me.

Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S POSITION ON DEC'S PROPOSED DEPRECIATION ANNUAL ACCRUAL.

A. DEC is proposing a depreciation annual accrual increase of $108.5 million based on December 31, 2018, investments.[2] The Public Staff's adjustments to DEC's filed depreciation rates result in a $48.5 million reduction to DEC's filed depreciation annual accrual, or an increase of $60.0 million to the depreciation annual accrual compared to the depreciation rates that were approved in the Commission's June 22, 2018, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in the Sub

[1] Sites visits included the Marshall Steam Station, Buck Combined Cycle Station, Lincoln Combustion Turbine Station, the Wiley Substation, and a new substation under construction. I also visited two sites where active aerial and underground projects were underway.

[2] Page 1 of NC-2601 of the September 30, 2019, Rate Case Information Report. These amounts are prior to any jurisdictional allocations.

1146 Proceeding ("Sub 1146 Order").

Q. PLEASE PROVIDE A COMPARISON OF THE ANNUAL DEPRECIATION RATE PROPOSALS.

A. The Public Staff's proposed depreciation rates compared to DEC's proposed depreciation rates are summarized below:

Table 1: Comparison of Depreciation Accrual Rates

Functional Category	12/31/18 Investment	Current Approved Depreciation Rate	DEC Proposed Depreciation Rate	Public Staff Proposed Depreciation Rate
A	B	C	D	E
Steam Production Plant	$8,352,937,230	3.41%	4.40%	3.90%
Nuclear Production Plant	8,518,494,363	3.39%	3.60%	3.60%
Hydraulic Production Plant	2,134,189,181	1.87%	2.00%	1.99%
Other Production Plant	3,153,387,534	3.09%	3.21%	3.12%
Transmission Plant	3,871,037,930	2.05%	2.23%	2.23%
Distribution Plant	12,022,021,973	2.27%	2.28%	2.24%
General Plant	1,150,068,086	5.45%	5.27%	5.27%
Land Rights	199,557,774	1.09%	0.98%	0.98%
General Plant Res. Amort.				
Total Depreciable Plant	**$39,401,694,071**	**2.84%**	**3.12%**	**2.99%**

The annualized accrual based on December 31, 2018, investments reflected in the 2018 Depreciation Study using the Public Staff's proposed depreciation rates compared to DEC's proposed depreciation rates is summarized below:

Table 2: Comparison of Annual Depreciation Accrual Amount

Functional Category	12/31/18 Investment	DEC Proposed Accrual Amount	Public Staff Proposed Accrual Amount
A	B	C	D
Steam Production Plant	$8,352,937,230	$367,923,551	$326,020,669
Nuclear Production Plant	8,518,494,363	306,886,916	306,886,916
Hydraulic Production Plant	2,134,189,181	42,784,187	42,377,657
Other Production Plant	3,153,387,534	101,212,036	98,537,143
Transmission Plant	3,871,037,930	86,253,267	86,253,267
Distribution Plant	12,022,021,973	273,848,655	269,624,535
General Plant	1,150,068,086	60,633,994	60,633,994
Land Rights	199,557,774	1,960,710	1,960,710
General Plant Res. Amort.		(13,907,418)	(13,907,418)
Total Depreciable Plant	**$39,401,694,071**	**$1,227,595,898**	**$1,178,387,474**

Q. PLEASE DESCRIBE EXHIBIT RMM-1.

A. Exhibit RMM-1 contains the calculations of the Public Staff's proposed depreciation rates for DEC's Electric Plant in North Carolina.

II. <u>Definition of Depreciation</u>

Q. COULD YOU PLEASE PROVIDE THE DEFINITION OF DEPRECIATION?

A. Yes. The Federal Energy Regulatory Commission ("FERC") definitions contained in the FERC Uniform System of Accounts ("FERC USOA") state:

> 12. *Depreciation,* as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the

> consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[3]

The FERC USOA definition of "depreciation" specifically states depreciation is a "loss in service value." FERC defines "service value" as "the difference between original cost and net salvage value of electric plant."[4]

Since this is a utility regulation proceeding, I rely on the FERC USOA definition of "depreciation," which focuses on the "loss of service value."

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF HOW REMAINING LIFE DEPRECIATION RATES ARE CALCULATED.

A. The remaining life depreciation rate formula is:

$$\text{Depreciation Rate} = \frac{(100\% - \text{Book Reserve }\% - \text{Future Net Salvage }\%)}{\text{Average Remaining Life}}$$

In the formula above, the book reserve percent is the actual reserve on the Company's books divided by the actual plant in service

[3] FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, as currently embodied in the United States Code of Federal Regulations, Title 18, Part 101.
[4] FERC USOA Definition 37.

investment on the Company's books. The book reserve percent is based on actual data from the Company's books and is not estimated in a depreciation study.

The future net salvage percent and the average remaining life are future estimates proposed in a depreciation study. A depreciation study estimates the projected average service life of the assets, the retirement pattern of those assets, and the cost of removing or retiring those assets less any expected salvage from the sale, scrap, insurance, reimbursements, etc. of those assets. These estimates are referred to as depreciation parameters.

The projected average service life and retirement pattern (survivor curve) are used to calculate the average remaining life.

The estimated future net salvage percent is the estimated future cost of removing or retiring less any estimated future salvage from sale, scrap, insurance, reimbursements, etc.

Q. PLEASE EXPLAIN WHAT IS MEANT BY NET SALVAGE.

A. The National Association of Regulatory Commissioners ("NARUC") publication *Public Utilities Depreciation Practices* defines net salvage as "the gross salvage for the property retired less its cost of removal."[5] Gross salvage is defined as "the amount recorded for the

[5] *Public Utilities Depreciation Practices*, published by NARUC, at p. 322 (1996).

property retired due to the sale, reimbursement, or reuse of the property."[6] Cost of removal is defined as "the costs incurred in connection with the retirement from service and the disposition of depreciable plant. Cost of removal may be incurred for plant that is retired in place."[7]

Q. WHY IS THE ESTIMATED FUTURE NET SALVAGE COSTS SHOWN AS A PERCENT?

A. The depreciation rates resulting from a depreciation study are applied to the investment amounts as of the date of the test year in the rate proceeding. Since a depreciation study produces a depreciation rate, the estimated future net salvage is incorporated into the depreciation rate formula as a percent of the investment.

Q. WHAT IMPACT DOES THE ESTIMATED FUTURE NET SALVAGE HAVE ON DEPRECIATION RATES?

A. Estimated positive future net salvage results in a lower depreciation rate, all other things being equal. Estimated negative future net salvage results in a higher depreciation rate, all other things being equal.

As explained in NARUC's *Public Utilities Depreciation Practices*:

> Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage

[6] *Id.* at p. 320.
[7] *Id.* at p. 317.

> occurs when cost of retirement exceeds gross salvage.[8]

In that same section of the text, NARUC concludes that:

> Cost of retirement, however, must be given careful thought and attention, since for certain types of plant, it can be the most critical component of the depreciation rate.[9]

The estimated future net salvage is part of the annual depreciation accrual, which is credited to the depreciation reserve to cover the estimated future net salvage costs the company may incur in the future associated with plant asset retirements.

III. <u>Estimated Terminal Net Salvage Costs (Decommissioning or Dismantlement Costs)</u>

Q. WHAT ARE ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS?

A. Estimated future terminal net salvage costs are estimated future costs that are associated with the closure and assumed demolition of a production plant that is no longer in service. These costs are also referred to as decommissioning or dismantlement costs.

Q. DID DEC INCLUDE ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS FOR POWER PRODUCTION PLANTS IN THE PROPOSED DEPRECIATION RATES?

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[8] *Id.* at p. 18.
[9] *Id.* at p. 19.

A. Yes. The estimated future terminal net salvage costs for power production plants included in DEC's proposed depreciation rates are supported by the Burns & McDonnell *Decommissioning Cost Estimate Study* ("DEC Decommissioning Cost Estimate Study") provided as Doss Exhibit 4 in the Sub 1146 Proceeding.[10] DEC's estimated future terminal net salvage costs for power production plants assumes **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**[11]

Q. IS IT CERTAIN THAT DEC WILL DEMOLISH THE STRUCTURES AND OTHER ASSETS WHEN A PRODUCTION PLANT RETIRES FROM SERVICE?

A. No. There are other alternatives that may not result in the demolition of the structures at the production plant site. One alternative is to convert a coal power production plant to a natural gas power production plant, which would not require the demolition of all the structures owned by DEC. Another alternative would be to sell the production plant, which would not require the demolition of all the structures owned by DEC.

Q. ARE YOU PROPOSING ADJUSTMENTS TO DEC'S ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS?

[10] DEC Decommissioning Cost Estimate Study, provided as Confidential Attachment in response to Public Staff Data Request 43-19, attached as Confidential Exhibit RMM-2.
[11] *Id.* at p. 21.

A. Yes. I am proposing to continue the use of the current approved 10% contingency for future "unknowns" included in DEC's estimated future terminal net salvage costs.

A. Contingency Factor for Future Unknown Costs

Q. WHAT IS THE CURRENT APPROVED CONTINGENCY FACTOR?

A. In its Sub 1146 Order, the Commission approved the use of a 10% contingency factor, instead of the 20% contingency factor included in the DEC Decommissioning Cost Estimate Study filed as Doss Exhibit 4 in that docket.

Regarding the appropriate contingency factor assumed in the DEC Decommissioning Cost Estimate Study, the Sub 1146 Order stated:

> The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e. increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company.[12]

Q. WHAT CONTINGENCY FACTOR DID DEC ASSUME IN THE FUTURE ESTIMATED TERMINAL NET SALVAGE COSTS IN THIS PROCEEDING?

[12] Sub 1146 Order at pp. 172-73.

A. In this proceeding, DEC's proposed future terminal net salvage costs are again supported by the same DEC Decommissioning Cost Estimate Study reviewed in the Sub 1146 Proceeding.[13]

DEC continued to assume the same 20% contingency factor "to cover unknowns," which escalates the estimated terminal net salvage costs in the depreciation rate calculation.

Q. WHAT DO YOU RECOMMEND REGARDING THE CONTINGENCY FACTOR?

A. I recommend the continued use of the Commission approved 10% contingency factor for the future estimated terminal net salvage costs included in the calculation of the depreciation rate.

B. Inflation of Electric Production Plant Estimated Future Terminal Net Salvage Costs

Q. IN THE SUB 1146 PROCEEDING, WHAT ACTION DID THE COMMISSION TAKE REGARDING THE FUTURE INFLATION YEAR FOR DEC'S ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS?

A. In its Sub 1146 Order, the Commission found that DEC's proposal to escalate estimated future terminal net salvage costs to the assumed year of final retirement was reasonable.

[13] DEC Decommissioning Cost Estimate Study, provided as Confidential attachment in response to Public Staff Data Request 43-19, attached as Confidential Exhibit RMM-2.

Q. IS THE PUBLIC STAFF RECOMMENDING A DIFFERENT APPROACH TO ESCALATING ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS IN THIS DOCKET THAN THE APPROACH APPROVED BY THE COMMISSION?

A. No. The Public Staff is not proposing a change to DEC's proposed escalation of the estimated future terminal net salvage costs in this proceeding.

Q. PLEASE EXPLAIN THE ISSUE REGARDING THE AMOUNT OF FUTURE INFLATION DEC INCLUDED IN THE ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS.

A. DEC is inflating the estimated future terminal net salvage costs to the assumed year of final retirement. The future terminal net salvage costs are estimated in the DEC Decommissioning Cost Estimate Study. The DEC Decommissioning Cost Estimate Study provides estimated future terminal net salvage costs in year-2016 dollars.[14]

In the 2018 Depreciation Study, these estimated future terminal net salvage costs are escalated to the year of the assumed retirement of the production plant and DEC proposes to collect a portion of these future inflated estimated costs from the current ratepayers in today's more valuable dollars.

[14] DEC response to Public Staff Data Request 43-17, attached as Exhibit RMM-3.

Q. Please explain how DEC is escalating the estimated future terminal net salvage costs.

A. Attached as Exhibit RMM-4 are pages from the 2018 Depreciation Study showing the calculation of the terminal net salvage costs included in the calculation of DEC's proposed depreciation rates.

Looking at the row for Cliffside, the estimated terminal net salvage cost of $48,075,000 shown in column (5) is in year-2016 dollars from the DEC Decommissioning Cost Estimate Study. In the 2018 Depreciation Study this $48,075,000 in year-2016 dollars is escalated to $105,945,615 in year-2048 dollars shown in column (6). This escalated $105,945,615 is calculated assuming an inflation rate of 2.5% per year to the year 2048 since the final Cliffside unit is estimated to retire in 2048.[15] This $105,945,615 escalated amount is 2.2 times the estimated terminal net salvage cost from the Decommissioning Cost Estimate Study.[16] DEC includes this escalated $105,945,615 in year-2048 dollars in its calculation of the depreciation rates to be collected from ratepayers starting in August 2020.[17]

[15] $48,075,000 in year-2016 dollars * (1 + 2.5% inflation) ^ (2048-2016 years) = $105,945,615 escalated year-2048 dollars.

[16] Spanos Exhibit 1 (2018 Depreciation Study) at p. 307. $105,945,615 in year-2048 dollars / $48,075,000 in year-2016 dollars = 2.2 times.

[17] Page 2 of DEC's September 30, 2019 "Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets" in this proceeding.

Q. PLEASE EXPLAIN HOW DEC INCLUDES THESE ESCALATED ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS IN THE PROPOSED CHARGES TO RATEPAYERS.

A. I will continue to use Cliffside for discussion purposes. The escalated $105,945,615 amount is in year-2048 dollars and used in the calculation of DEC's proposed depreciation accrual in the 2018 Depreciation Study.[18] These escalated year-2048 dollars are included in the DEC proposed ratepayer charges in current dollars.

The concern is not that year-2048 dollars are worth less than current dollars. Rather, determining the cost of removal in year-2048 dollars and then collecting the inflated costs from current customers in more valuable current dollars is unreasonable, since it imposes on today's ratepayers too much of the risk associated with a significantly long period of estimated future inflation.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY MORE VALUABLE CURRENT DOLLARS.

A. Due to inflation, the year-2048 nominal dollar will have a lower purchasing power than today's nominal dollar.

[18] The inflated amounts are spread over the remaining life, but current customers are still paying with the more valuable current dollars.

Q. DOES THE ANNUAL INFLATION RATE OF 2.5% ASSUMED IN DEC'S INFLATION OF TERMINAL NET SALVAGE COSTS INCLUDE A CHANGE IN THE PURCHASING POWER OF A DOLLAR?

A. Yes. DEC is assuming that a year-2048 dollar is worth only 45¢ compared to a year-2016 dollar.[19]

The problem of paying year-2048 dollars today can be explained by a simple example. Assume a savings bond worth $106,000 matures in 32 years. Assuming a 2.5% interest rate, that savings bond has a present market value of $48,000.[20] No reasonable investor would pay $106,000 using today's dollars for a savings bond that would return $106,000 in 32 years.

Similarly, charging current ratepayers' depreciation expense on the basis of estimated future terminal net salvage costs calculated in year-2048 dollars places too high a burden of future inflation on those ratepayers.

Q. ARE THERE OTHER ESTIMATED FUTURE COSTS THAT COMPANIES ESCALATE?

A. Yes, however, these escalated estimated future retirement costs are then present-valued and collected or booked based on current

[19] Spanos Exhibit 1 (2018 Depreciation Study) at p. 307. $48,075,000 / $105,945,615 = $0.454.

[20] Assuming 2.5% interest for 32 years. $106,000 / (1+2.5%) ^ 32 = $48,099.

dollars and not the escalated dollars.

For example, utility companies are required to escalate estimated future retirement costs related to nuclear power plants and other legal asset retirement obligations ("ARO").

Regarding estimated Nuclear Decommissioning costs, NARUC's *Public Utilities Depreciation Practices* points out that the escalated estimated future retirement costs are recovered using current dollars as calculated using a sinking fund annuity formula to determine the needed annual amounts.21

Additionally, legal AROs estimated future inflated dollars are discounted back to present value dollars to determine the annual amounts reflected on the company's books.[22]

Q. IF YOU WERE RECOMMENDING A CHANGE TO THE COMMISSION'S DECISION REGARDING THE ESCALATION OF THE ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS IN THIS PROCEEDING, WOULD YOU BE RECOMMENDING THE USE OF A SINKING FUND ANNUITY CALCULATION OR A DISCOUNT RATE TO CALCULATE THE PRESENT VALUE OF

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[21] *Public Utilities Depreciation Practices*, at p. 308.

[22] Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS 143). An example of a legal ARO that DEC is required to account for using this method are costs related to their ash basin closures, as discussed in the Direct Testimony of Jane L. McManeus, page 19 lines 9-11 in this proceeding.

THE DEC ESCALATED ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS?

A. No. The concern of collecting the inflated estimated costs that are not certain to occur from current customers in more valuable current dollars can be addressed by the use of a more reasonable escalation year.

Q. WHAT IS A REASONABLE ESCALATION YEAR WITH RESPECT TO ESTIMATED TERMINAL NET SALVAGE COSTS?

A. Inflating the DEC estimated terminal net salvage costs to year-2023 dollars is one reasonable option.

DEC's 2018 Depreciation Study states that:

> The annual depreciation accrual rates are applicable specifically to the electric plant in service as of December 31, 2018. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2018, is reasonable for a period of three to five years.[23]

Inflating to the year-2023 would inflate the terminal net salvage costs to the level of the dollars collected from the ratepayers for the time period the rates set in this proceeding are expected to be reasonable. This reduces the risk placed on today's ratepayers, without exposing the Company to a risk that it will not be able to collect its actual net

[23] Spanos Exhibit 1 (2018 Depreciation Study) at p. 56.

salvage costs over the long-term.

Escalating the estimated future terminal net salvage costs to the final retirement year, on the other hand, collects the more valuable current dollars to pay for the full amount of the inflated future estimated terminal net salvage costs and thus places more of the risk of future inflation onto today's ratepayers.

Q. ARE YOU AWARE OF OTHER JURISDICTIONS THAT HAVE REMOVED THE ESCALATION OF ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS?

A. Yes. The Corporation Commission of the State of Oklahoma stated in an Order: "Furthermore, the Commission rejects Mr. Spanos's escalation of the production plant demolition cost estimates."[24]

The Arizona Corporation Commission accepted a Settlement in which the dismantlement costs were set to "current dollars" in the calculation of the depreciation rates.25

Additionally, the Missouri Public Service Commission and West Virginia Public Service Commission have issued Orders that excluded terminal net salvage for production plants in the calculation

[24] Oklahoma Cause No. PUD 201700151, paragraph 107 of the ALJ Report adopted in Order No. 672864. (January 31, 2018).

[25] Arizona Corporation Commission Docket No. E-01933A-15-0239, Decision No. 75975 at p. 10 (February 24, 2017). *See also* Page 9, lines 6-12 of the July 25, 2016 TEP Rebuttal testimony of David J. Lewis.

of depreciation rates.[26]

IV. <u>Other Production Plant Interim Net Salvage</u>

Q. WHAT ARE PRODUCTION PLANT INTERIM NET SALVAGE COSTS?

A. Interim net salvage costs are estimated future costs associated with the retirements that occur prior to the closure of a production plant that has ceased operations. These interim net salvage costs are in addition to any estimated future terminal net salvage costs.

Q. DID THE COMMISSION INDICATE THE INTERIM NET SALVAGE PERCENTAGES FOR OTHER PRODUCTION ACCOUNTS 342, 343, 344, 345, AND 346 COULD BE REEXAMINED IN FUTURE RATE BASE CASES.

A. Yes. In its Sub 1146 Order, the Commission stated:

> Based on the evidence discussed above and the entire record in this case, the Commission finds that the Public Staff's proposal to set an interim net salvage percentage of 0 for Accounts 342, 343, 344, 345, and 346 is reasonable. Historical data show that using a negative value, as was previously set, has resulted in DEC overcollecting its costs. It would be inequitable to charge customers for costs that the utility is unlikely to incur. As discussed previously, the Company has stated publicly that it plans to file multiple rate cases

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[26] *See* Missouri Public Service Commission Case No. ER-2004-0570, Report and Order at p. 53 (March 10, 2005); and West Virginia Public Service Commission Case No. 06-1426-E-D, Commission Order at p. 57, Conclusion of Law Item 25 (May 22, 2007).

> between 2019 and 2023, and therefore, this issue can be reexamined in the next base rate case.[27]

Q. DID YOU REVIEW THE INTERIM NET SALVAGE PERCENTAGES FOR PRODUCTION PLANTS INCLUDED IN DEC'S PROPOSED DEPRECIATION RATES?

A. Yes. Attached as RMM-5 is the DEC response to discovery showing the interim net salvage percentages DEC proposes for the Steam Production Accounts.[28]

Q. ARE YOU PROPOSING ADJUSTMENTS TO DEC'S ESTIMATED INTERIM NET SALVAGE PERCENTAGES?

A. Yes. For Other Production Accounts 342, 343, 344, 345, and 346, DEC proposes a -5% interim net salvage percentage. However, the historical analyses for these accounts show that on average the net salvage has been a positive $6,404,164 per year for the last 3 years and a positive $7,593,793 per year for the last 5 years.[29] A positive net salvage amount means that DEC has booked gross salvage amounts that have more than covered the incurred cost of removal.

In other words, DEC does not need to collect interim removal costs from the ratepayers for these accounts, since it has more than

[27] Sub 1146 Order at p. 177.
[28] DEC response to Public Staff Data Request 76-1, attached as Exhibit RMM-5.
[29] Spanos Exhibit 1 (2018 Depreciation Study) at pp. 326-27, 329-31, attached as Exhibit RMM-6.

recovered those interim removal costs in its booked gross salvage.

I am proposing the continued use of a 0% interim net salvage since in DEC's actual experience it has not incurred interim net removal costs. This 0% interim net salvage does not include the final decommissioning costs; these are just the net salvage costs of retirements that occur prior to the final decommissioning of the plants.

V. <u>Advanced Metering Infrastructure ("AMI") Meter Service Life</u>

Q. WHAT SERVICE LIFE DOES DEC RECOMMEND FOR THE AMI METERS?

A. DEC is proposing a 15-year average service life for AMI Meters.

Q. WHAT IS THE LIFE RANGE INDICATED BY THE MANUFACTURER OF THE AMI METERS?

A. In response to discovery, DEC stated that the manufacturer **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

[30] DEC Confidential response to Public Staff Data Request 43-12, attached as Confidential Exhibit RMM-7.

Q. WHAT LIFE DO YOU RECOMMEND FOR AMI METERS?

A. DEC's deployment of AMI meters has primarily occurred since 2014, so it has limited historic data on the service life of AMI meters. I therefore recommend a 17-year life **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

VI. <u>Mass Property Future Net Salvage</u>

Q. DID YOU REVIEW THE REASONABLENESS OF DEC'S PROPOSED FUTURE NET SALVAGE FOR A MASS PROPERTY ACCOUNT?

A. Yes. For Account 366, Underground Conduit I recommend future net salvage ("FNS") percent of -10% that differs from DEC's proposed -15%.

Q. PLEASE EXPLAIN WHAT FACTORS DEC CONSIDERED IN THE ESTIMATION OF THE PROPOSED FUTURE NET SALVAGE PERCENTS.

A. Mr. Spanos included the historic net salvage ratios calculated in the 2018 Depreciation Study as part of his analysis.

In his direct testimony, Mr. Spanos states:

> The net salvage percentages estimated in the Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided to me by the Company's operating personnel, general knowledge and experience of industry practices; and trends in the industry in general. The statistical net salvage analyses incorporate the Company's actual historical data for the period 2003 through 2018, and considers the cost of removal and gross salvage ratios to the associated retirements during the 16-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.[31]

The DEC 2018 Depreciation Study included the analysis of the historic data of incurred net salvage and related retirements. Regarding historic net salvage, the 2018 Depreciation Study states:

> The estimates of net salvage by account were based in part on historical data compiled through 2018. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.[32]

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[31] Direct Testimony of John J. Spanos at p. 13, lines 10-18.
[32] Spanos Exhibit 1 (2018 Depreciation Study) at p. 44.

Q. WHAT IS A CONCERN REGARDING THE HISTORIC NET SALVAGE RATIOS CALCULATED IN THE 2018 DEPRECIATION STUDY?

A. As pointed out in Wolf and Fitch's *Depreciation Systems*:

> Salvage ratios are a function of inflation.[33]

Additionally, *Depreciation Systems*, points out that a historic net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator is a ratio using different units, stating:

> One inherent characteristic of the salvage ratio is that the numerator and denominator are measured in different units; the numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation. Inflation is an economic fact of life and although both numerator and denominator are measured in dollars, the timing of the cash flows reflects different price levels.[34]

The calculation of the historic net salvage ratio includes the impact of high historic inflation rates since the net salvage amount in the numerator is in current dollars and the cost of the plant (which may have been installed decades before) in the denominator is in historic

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[33] Wolf, Frank K. and Fitch, W. Chester *Depreciation Systems* (Iowa State University Press, 1994) at p. 267.

[34] *Id.* at p. 53.

dollars. In other words, due to inflation, the amounts in numerator and denominator of the net salvage ratio are at different price levels.

Q. IS THE FACT THAT HISTORIC INFLATION IS INCLUDED IN THE NET SALVAGE RATIO RECOGNIZED IN ANOTHER AUTHORITATIVE DEPRECIATION TEXT?

A. Yes. Regarding inflation, NARUC's *Public Utilities Depreciation Practices* states:

> The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a tendency for costs of retirement, typically labor, to increase more rapidly than material prices.[35]

As stated earlier in this testimony, NARUC also points out that careful consideration should be given to the net salvage estimate stating:

> Cost of retirement, however, must be given careful thought and attention, since for certain types of plant, it can be the most critical component of the depreciation rate"[36]

Q. HAVE OTHER JURISDICTIONS CONSIDERED THE IMPACT OF INFLATION IN THE SETTING OF THE FUTURE NET SALVAGE PERCENT?

A. Yes. I am aware of several jurisdictions that have adopted future net salvage percents that recognized the inflated dollars included in the

[35] *Public Utilities Depreciation Practices*, at p. 19.
[36] *Id.* at p. 19.

historic net salvage ratio and adopted future net salvage percent that recognizes the time value of cost of removal due to inflation.

- The Connecticut Public Utilities Regulatory Authority, in its December 14, 2016 Decision in Docket No. 16-06-04, accepted net salvage depreciation rates that produced "an annual accrual that is 1.2 times the annual incurred distribution plant net salvage costs" stating that the "distribution net salvage depreciation rates still comfortably cover the actual incurred net salvage costs."[37]

- The Public Service Commission of the District of Columbia Order No. 15710 stated:

> Fairness and equity require that the Commission adopt a methodology that, to the extent possible, balances the interest of current and future ratepayers." And went on to state: "Pepco should not be allowed to charge current customers for future inflation, nor should Pepco be allowed to charge current customers in higher-value current dollars for a future cost of removal amount that is calculated in lower-value future dollars.[38]

- The Public Service Commission of Maryland, in its Order No. 81517 stated:

> The Commission has carefully reviewed the record and finds that the Present Value Method should be adopted for the recovery of removal costs. The Straight Line Method recovers the same annual cost in nominal dollars from ratepayers today as it does at the time plant is removed from service. However, a dollar is

[37] Connecticut Public Utilities Regulatory Authority Docket No. 16-06-04, Decision at p. 46. (December 14, 2016).

[38] Public Service Commission of the District of Columbia Formal Case No. 1076, Order No. 15710 at paragraph 252 (March 2, 2010).

> worth substantially more today than it will be 20 to 40 years from now. Consequently, today's ratepayers would pay more in "real" dollars under the Straight Line Method for the recovery costs of the plant they consume than would future ratepayers when net salvage is negative, as everyone projects.[39]

- The New Jersey Board of Public Utilities found:

> As a result of this data and the underlying concept of FASB 143 as discussed in this matter, the Board FINDS it appropriate to revisit the concept of including estimated future net salvage in current depreciation rates. The Board HEREBY FINDS the recommendation of the Ratepayer Advocate and Staff to exclude estimated net salvage from depreciation rates to be appropriate. The Board FURTHER FINDS that the Ratepayer Advocate and Staff's proposed utilization of a five-year average of actual salvage expense in depreciation expense is reasonable as it more closely aligns the amount recovered in base rates with the historical level of expenses incurred. The Board concurs with Staff that the ten-year window of actual experience rather than the five-year rolling average proposed by the Ratepayer Advocate is appropriate.[40]

- The Pennsylvania Superior Court found:

> Negative salvage attributed to existing plant is purely prospective; it is a cost which has not yet been incurred; it is uncertain when and if it will be incurred; and it is not a part of the original cost of construction of the facilities when first devoted to public service. To permit the recovery of prospective negative salvage is to permit the recovery of a total amount in excess of the original cost of construction prior to the actual expenditure of those costs and, in our opinion, represents the recovery of something in the nature of a future reproduction cost. The established law in this Commonwealth does not permit the recovery by

[39] Public Service Commission of Maryland Case No. 9092, Order No. 81517, at p. 9 (July 9, 2007).

[40] New Jersey Docket No. ER02080506, Final Order at pp. 129-30 (May 14, 2004).

> annual depreciation of any such prospective excess. It is therefore the prospective nature of future negative salvage that prevents it from being considered either in accrued depreciation or in the allowance for annual depreciation; they must have a consistent basis under our law.[41]

Q. IS THE DEC PROPOSED FUTURE NET SALVAGE PERCENT BASED SOLELY ON HISTORIC NET SALVAGE RATIOS CALCULATED IN THE 2018 DEPRECIATION STUDY?

A. No. The calculated historic net salvage ratios for Account 366, Underground Conduit are included in the 2018 Depreciation Study, attached as Exhibit RMM-8 for convenience.[42]

DEC's proposed -15% future net salvage percent is not one of the historic net salvage ratios calculated in the 2018 Depreciation Study. Based on the calculations in the 2018 Depreciation Study, the overall historic net salvage ratio is -21%, the five-year average historic net salvage ratio is -9%, and the three-year average historic net salvage ratios range from -904% to +946%. So DEC's proposed -15% is not based solely on the calculated historic net salvage ratios.

Q. HAVE YOU REVIEWED THE RECOVERY OF FUTURE NET SALVAGE COSTS INCLUDED IN DEC'S PROPOSED DEPRECIATION RATES AND THE ACTUAL NET SALVAGE COSTS DEC HAS INCURRED IN THE RECENT PAST?

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[41] Pennsylvania, Superior Court of Pennsylvania in Penn Sheraton Hotel v. Pennsylvania Public Utility Commission, 184 A.2d 324, 329 (Pa. Super. Ct. 1962).
[42] Spanos Exhibit 1 (2018 Depreciation Study) at p. 342.

A. Yes. Instead of relying solely on the historic net salvage ratios, which are influenced by historic inflation levels, I also reviewed the future net salvage costs included in DEC's proposed depreciation accrual and the actual net salvage costs incurred by DEC on average over the recent five-year period.

Q. PLEASE PROVIDE THE COMPARISON OF DEC'S ACTUAL NET SALVAGE INCURRED AND PROPOSED ANNUAL ACCRUAL FOR FUTURE NET SALVAGE.

A. Table 3 below is a comparison of the actual net salvage costs incurred by DEC on average over the recent five-year period to future net salvage costs included in DEC's and the Public Staff's proposed depreciation accruals.

Table 3: Comparison of Actually Incurred Net Salvage and Net Salvage in Proposed Depreciation Rates as of December 31, 2018 Investments[43]

Account	Description	Five Year Net Salvage Actually Incurred	Net Salvage Recovery included in DEC's Proposed Depr Rates	DEC Proposed / Actually Incurred	Net Salvage Recovery included in Staff's Proposed Depr Rates	Staff Proposed / Actually Incurred
		A	B	C=B/A	D	E=D/A
	DISTRIBUTION PLANT					
361.00	Structures and Improvements	$145,618	$201,338	1.4	$201,338	1.4
362.00	Station Equipment	2,022,712	5,376,901	2.7	5,376,901	2.7
364.00	Poles, Towers, and Fixtures	3,705,637	7,987,869	2.2	7,987,869	2.2
365.00	Overhead Conductors and Devices	5,035,477	8,911,867	1.8	8,911,867	1.8
366.00	**Underground Conduit**	**16,256**	**364,157**	**22.4**	**231,716**	**14.3**
367.00	Underground Conductors and Devices	1,667,105	6,669,853	4.0	6,669,853	4.0
368.00	Line Transformers	1,208,168	2,844,510	2.4	2,844,510	2.4
369.00	Services	353,845	2,005,311	5.7	2,005,311	5.7
370.00	Metering Equip & Meters	(106,352)	0	0.0	0	0.0
370.02	Meters - Utility of the Future	0	0		0	
371.00	Installations on Customers' Premises	278,291	1,016,108	3.7	1,016,108	3.7
373.00	Street Lighting and Signal Systems	788,681	547,311	0.7	547,311	0.7
	TOTAL DISTRIBUTION PLANT	**$15,115,438**	**$35,925,225**	**2.4**	**$35,792,784**	**2.4**

Q. ARE YOUR PROPOSED FUTURE NET SALVAGE PERCENTS BASED ONLY ON THE HISTORICAL ANALYSIS SHOWN IN TABLE 3 ABOVE?

A. No, which is supported by the fact that my proposed future net salvage accrual amounts are not equal to the average annual historical amount as shown in Table 3 above. Table 3 provides a

[43] This table is based on the December 31, 2018 investment levels used in the 2018 Depreciation Study.

reasonableness check of the proposed future net salvage percents. My proposed future net salvage accrual amounts consider DEC's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and my previous experience.

Q. PLEASE EXPLAIN HOW YOUR FUTURE NET SALVAGE BUILDS THE RESERVE FOR FUTURE NET SALVAGE COSTS.

A. Using Account 366, Underground Conduit for discussion, as shown in Table 3 above, DEC actually incurred $16,256 on average per year, however, DEC proposes to collect a $364,157 net salvage annual accrual.[44] The annual accrual amount is an expense to be recovered from ratepayers in customer charges.[45] The annual accrual DEC is proposing for net salvage is about 22.4 times the average annual amount DEC has actually recently incurred for net salvage.

Under my recommendation, the annual accrual for Account 366, Underground Conduit net salvage would still be $231,716, which is about 14.3 times the average annual amount DEC actually incurred.[46] My recommendation provides recovery of the expected

[44] Annual accrual amount based on investments as of December 31, 2018.
[45] The exact amount to be recovered from ratepayers will vary when calculated on investments other than the investment as of December 31, 2018.
[46] Annual accrual amount based on investments as of December 31, 2018. I am not recommending or implying a change from the "accrual" basis to the "cash" basis for the

cost of removal in the near future and builds the reserve for the future cost of removal associated with future retirements.

VII. <u>Cliffside Unit 5 and Allen Final Retirement Year</u>

Q. WHAT FINAL RETIREMENT YEAR ARE INCLUDED IN THE CALCULATED DEPRECIATION RATES FOR CLIFFSIDE UNIT 5 AND ALLEN?

A. At the request of Public Staff, I have used the current approved final retirement year for Cliffside Unit 5 and Allen in the calculation of the Public Staff proposed depreciation rates. This analysis, and the Public Staff's proposed adjustment to the depreciation expense, are discussed further in the testimony of Public Staff witness Michelle Boswell.

VIII. <u>Conclusion</u>

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. For the reasons stated above, I recommend that the Public Staff's proposed depreciation rates shown on Exhibit RMM-1 be approved for DEC.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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recovery of future net salvage costs. In other words, I am not recommending or implying that the depreciation accrual no longer be credited to the Accumulated Provision for Depreciation or that the net salvage costs be "expensed".

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

<table>
<tr><td>DOCKET NO. E-7, SUB 1213

In the Matter of
Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina

DOCKET NO. E-7, SUB 1214

In the Matter of
Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina</td><td>)
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)</td><td>SUPPLEMENTAL TESTIMONY OF ROXIE MCCULLAR ON BEHALF OF PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION</td></tr>
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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

Testimony of Roxie McCullar

On Behalf of the Public Staff

North Carolina Utilities Commission

March 25, 2020

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roxie McCullar. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. ARE YOU THE SAME ROXIE MCCULLAR THAT PRE-FILED DIRECT TESTIMONY ON BEHALF OF THE PUBLIC STAFF OF THE NORTH CAROLINA UTILITIES COMMISSION ON FEBRUARY 18, 2020 IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my Supplemental Testimony is two-fold. First, I am including as Appendix A to this testimony a statement of my qualifications and experience that was inadvertently excluded from my February 18, 2020, Direct Testimony in this docket. Second, I am providing testimony to support the 2.17% distribution plant composite depreciation rate excluding AMR Meters used by Public Staff witness Michelle Boswell in her Supplemental Testimony.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE 2.17% DISTRIBUTION PLANT COMPOSITE DEPRECIATION RATE EXCLUDING AMR METERS?

A. At the request of Public Staff, I calculated the distribution plant composite depreciation rate excluding AMR Meters based on the depreciation rates I proposed in my Direct Testimony and shown in my Direct Exhibit RMM-1.

Table 1: Composite Depreciation Rate Excluding AMR Meters[1]

Amounts from Exhibit RMM-1	12/31/2018 Investment	Public Staff Proposed Annual Depr	Public Staff Proposed Depr Rate
Total Distribution Plant	$ 12,022,021,973	$ 269,624,535	2.24%
AMR Meters	$ 68,544,544	$ 10,601,895	
Distribution Composite w/o AMR Meters	$ 11,953,477,429	$ 259,022,640	**2.17%**

This adjustment is discussed further in the Supplemental Testimony of Public Staff witness Michelle Boswell.

[1] Exhibit RMM-1 at p. 15.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

Roxie McCullar, CPA, CDP
8625 Farmington Cemetery Road
Pleasant Plains, IL

Roxie McCullar is a regulatory consultant, licensed Certified Public Accountant in the state of Illinois, and a Certified Depreciation Professional through the Society of Depreciation Professionals. She is a member of the American Institute of Certified Public Accountants, the Illinois CPA Society, and the Society of Depreciation Professionals. Ms. McCullar has received her Master of Arts degree in Accounting from the University of Illinois-Springfield as well as her Bachelor of Science degree in Mathematics from Illinois State University. Ms. McCullar has 20 years of experience as a regulatory consultant for William Dunkel and Associates. In that time, she has filed testimony in over 50 state regulatory proceedings on depreciation issues and cost allocation for universal service and has assisted Mr. Dunkel in numerous other proceedings.

Education

Master of Arts in Accounting from the University of Illinois-Springfield, Springfield, Illinois

12 hours of Business and Management classes at Benedictine University-Springfield College in Illinois, Springfield, Illinois

27 hours of Graduate Studies in Mathematics at Illinois State University, Normal, Illinois

Completed Depreciation Fundamentals training course offered by the Society of Depreciation Professionals

Relevant Coursework:

- Calculus
- Number Theory
- Linear Programming
- Finite Sampling
- Introduction to Micro Economics
- Principles of MIS
- Introduction to Managerial Accounting
- Intermediate Financial Accounting I
- Advanced Financial Accounting
- Accounting Information Systems
- Fraud Forensic Accounting
- Commercial Law
- Advanced Auditing
- Discrete Mathematics
- Mathematical Statistics
- Differential Equations
- Statistics for Business and Economics
- Introduction to Macro Economics
- Introduction to Financial Accounting
- Intermediate Managerial Accounting
- Intermediate Financial Accounting II
- Auditing Concepts/Responsibilities
- Federal Income Tax
- Accounting for Government & Non-Profit
- Advanced Utilities Regulation
- Advanced Corp & Partnership Taxation

Current Position: Consultant at William Dunkel and Associates

Participation in the proceedings below included some or all of the following:

> Developing analyses, preparing data requests, analyzing issues, writing draft testimony, preparing data responses, preparing draft questions for cross examination, drafting briefs, and developing various quantitative models.

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2019	Kansas	Kansas Corporation Commission	20-UTAT-032-KSF	United Telephone Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2019	Kansas	Kansas Corporation Commission	19-ATMG-525-RTS	Atmos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2019	Kansas	Kansas Corporation Commission	19-GNBT-505-KSF	Golden Belt Telephone Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2019	Arizona	Arizona Corporation Commission	E-01933A-19-0028	Tucson Electric Power Company	Electric Depreciation Issues	The Utilities Division Staff Arizona Corporation Commission
2019	North Carolina	North Carolina Utilities Commission	E-22, SUB 562	Dominion Energy North Carolina	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2019	Utah	Public Service Commission of Utah	19-057-03	Dominion Energy Utah	Natural Gas Depreciation Issues	Division of Public Utilities
2019	Kansas	Kansas Corporation Commission	19-EPDE-223-RTS	Empire District Electric Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2019	Arizona	Arizona Corporation Commission	T-03214A-17-0305	Citizens Telecommunications Company	Arizona Universal Service Fund	The Utilities Division Staff Arizona Corporation Commission
2018	Kansas	Kansas Corporation Commission	18-KGSG-560-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2018	Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power & Light Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2018	Rhode Island	Rhode Island and Providence Plantations Public Utilities Commission	4800	SUEZ Water	Water Depreciation Issues	Division of Public Utilities and Carriers
2018	Rhode Island	Rhode Island and Providence Plantations Public Utilities Commission	4770	Narragansett Electric Company	Electric & Natural Gas Depreciation Issues	Division of Public Utilities and Carriers

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2018	North Carolina	North Carolina Utilities Commission	E-7, SUB 1146	Duke Energy Carolinas, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2017	DC	District of Columbia Public Service Commission	FC1150	Potomac Electric Power Company	Electric Depreciation Issues	District of Columbia Public Service Commission
2017	North Carolina	North Carolina Utilities Commission	E-2, SUB 1142	Duke Energy Progress, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2017	Washington	Washington Utilities & Transportation Commission	UE-170033 & UG-170034	Puget Sound Energy	Electric & Natural Gas Depreciation Issues	Washington State Office of the Attorney General, Public Council Unit
2017	Florida	Florida Public Service Commission	160186-EI & 160170-EI	Gulf Power Company	Electric Depreciation Issues	The Citizens of the State of Florida
2016	Kansas	Kansas Corporation Commission	16-KGSG-491-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2016	DC	District of Columbia Public Service Commission	FC1139	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2016	Arizona	Arizona Corporation Commission	E-01933A-15-0239 & E-01933A-15-0322	Tucson Electric Power Company	Electric Depreciation Issues	The Utilities Division Staff Arizona Corporation Commission
2016	Georgia	Georgia Public Service Commission	40161	Georgia Power Company	Addressed Depreciation Issues	Georgia Public Service Commission Public Interest Advocacy Staff
2016	DC	District of Columbia Public Service Commission	FC1137	Washington Gas & Light	Depreciation Issues	District of Columbia Public Service Commission
2015	Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Amos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-TWVT-213-AUD	Twin Valley Telephone, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2015	Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power & Light Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-MRGT-097-AUD	Moundridge Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2014	Kansas	Kansas Corporation Commission	14-S&TT-525-KSF	S&T Telephone Cooperative Association, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2014	Kansas	Kansas Corporation Commission	14-WTCT-142-KSF	Wamego Telecommunications Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	Kansas	Kansas Corporation Commission	13-PLTT-678-KSF	Peoples Telecommunications, LLC	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	New Jersey	State of New Jersey Board of Public Utilities	BPU ER12121071	Atlantic City Electric Company	Electric Depreciation Issues	New Jersey Rate Counsel
2013	Kansas	Kansas Corporation Commission	13-JBNT-437-KSF	J.B.N. Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	Kansas	Kansas Corporation Commission	13-ZENT-065-AUD	Zenda Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	DC	District of Columbia Public Service Commission	FC1103	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2012	Kansas	Kansas Corporation Commission	12-LHPT-875-AUD	LaHarpe Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2012	Kansas	Kansas Corporation Commission	12-GRHT-633-KSF	Gorham Telephone Company	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2012	Kansas	Kansas Corporation Commission	12-S&TT-234-KSF	S&T Telephone Cooperative Association, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2011	DC	District of Columbia Public Service Commission	FC1093	Washington Gas & Light	Depreciation Issues	District of Columbia Public Service Commission
2011	Kansas	Kansas Corporation Commission	11-CNHT-659-KSF	Cunningham Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2011	Kansas	Kansas Corporation Commission	11-PNRT-315-KSF	Pioneer Telephone Association	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2010	Kansas	Kansas Corporation Commission	10-HVDT-288-KSF	Haviland Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2009	Kansas	Kansas Corporation Commission	09-BLVT-913-KSF	Blue Valley Tele-Communications, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2009	DC	District of Columbia Public Service Commission	FC1076	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2008	Kansas	Kansas Corporation Commission	09-MTLT-091-KSF	Mutual Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	08-MRGT-221-KSF	Moundridge Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2007	Kansas	Kansas Corporation Commission	07-PLTT-1289-AUD	Peoples Telecommunications, LLC	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	07-MDTT-195-AUD	Madison Telephone, LLC	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	06-RNBT-1322-AUD	Rainbow Telecommunications Assn., Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-WCTC-1020-AUD	Wamego Telecommunications Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-H&BT-1007-AUD	H&B Communications, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-ELKT-365-AUD	Elkhart Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-SCNT-1048-AUD	South Central Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Utah	Public Service Commission of Utah	05-2302-01	Carbon/Emery Telecom, Inc.	Cost Study Issues & Depreciation Issues	Utah Committee of Consumer Services
2005	Kansas	Kansas Corporation Commission	05-TTHT-895-AUD	Totah Communications, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Maine	Public Utilities Commission of the State of Maine	2005-155	Verizon	Depreciation Issues	Office of Public Advocate
2005	Kansas	Kansas Corporation Commission	05-TRCT-607-KSF	Tri-County Telephone Association	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2005	Kansas	Kansas Corporation Commission	05-CNHT-020-AUD	Cunningham Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-KOKT-060-AUD	KanOkla Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-UTAT-690-AUD	United Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-CGTT-679-RTS	Council Grove Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-GNBT-130-AUD	Golden Belt Telephone Association	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	03-TWVT-1031-AUD	Twin Valley Telephone, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-HVDT-664-RTS	Haviland Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-WHST-503-AUD	Wheat State Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-S&AT-160-AUD	S&A Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-JBNT-846-AUD	JBN Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-S&TT-390-AUD	S&T Telephone Cooperative Association, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-BLVT-377-AUD	Blue Valley Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2001	Kansas	Kansas Corporation Commission	01-PNRT-929-AUD	Pioneer Telephone Association, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-BSST-878-AUD	Bluestem Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-SFLT-879-AUD	Sunflower Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-CRKT-713-AUD	Craw-Kan Telephone Cooperative, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	11-RNBT-608-KSF	Rainbow Telecommunications Association	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-SNKT-544-AUD	Southern Kansas Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-RRLT-518-KSF	Rural Telephone Service Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2000	Illinois	Illinois Commerce Commission	98-0252	Ameritech	Cost Study Issues	Government and Consumer Intervenors

MS. DOWNEY: And then with respect to Public Staff witness Scott J. Saillor, pursuant to the Commission's Order dated July 16th, 2020, we would move into evidence his testimony and exhibits filed February 18, 2020, consisting of 11 pages, an Appendix A, and five exhibits, and supplemental testimony and exhibits filed March 25, 2020, consisting of four pages and five exhibits.

CHAIR MITCHELL: Hearing no objection, your motion is allowed.

(Whereupon, the prefiled testimony and Appendix A, and the prefiled supplemental testimony of Scott J. Saillor was copied into the record as if given orally from the stand.)

(Whereupon, Public Staff Saillor Exhibits 1 through 5 filed with direct testimony, and Public Staff Saillor Exhibits 1 through 5 filed with supplemental testimony were admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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	)))))))))))))))	TESTIMONY OF SCOTT J. SAILLOR PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

TESTIMONY OF SCOTT J. SAILLOR
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 Scott J. Saillor. 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 to the Commission my recommendations on annualizing revenue, weather normalization, customer growth and change in usage.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO ANNUALIZE RETAIL REVENUES FOR CURRENT RATES.

A. This adjustment annualizes revenue based on the rates in effect at the time of the application, revises the fuel component of base rates, and removes test period revenues recovered through the annual cost riders.

Q. DOES THE PUBLIC STAFF HAVE ANY CHANGES FOR THIS ADJUSTMENT?

A. No. The Public Staff reviewed this adjustment and does not have any recommended changes.

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION REVENUE ADJUSTMENT.

A. Monthly kilowatt-hour (kWh) adjustments are determined to weather normalize test period sales for the Residential, General and Industrial rate classes. The revenue adjustment is calculated by multiplying the total rate class kWh adjustment by the average customer class rates based on annualized revenues divided by per book sales.

Q. WHAT CHANGES DO YOU RECOMMEND FOR THIS ADJUSTMENT?

A. The annualized revenues used to calculate average rates include revenues generated from per-bill basic facilities charges. However, because the weather effect does not change the number of bills rendered during the test period, the weather normalization adjustment would not increase or decrease revenues from basic facilities charges. To account for this, I removed the basic facilities charge revenues from DEC's calculations for the average customer class rates.

In addition, I summed the monthly NC Retail kWh weather adjustments updated through November 2019, as provided to the Public Staff by DEC, for each month of the test period for each customer class. Each monthly adjustment is based on the monthly System weather adjustment and each month's NC sales to System sales ratio. This is in place of the method used in the E-1 Item 10 worksheet NC-0301 where the NC Retail kWh weather adjustment per class is calculated by multiplying the test period System kWh weather adjustment times the annual NC Retail to System sales ratio. I believe that summing the monthly NC Retail kWh adjustments more accurately reflects the normal weather adjustment being represented by DEC.

These changes, as shown in Saillor Exhibits 1 and 2, were provided to Public Staff witness Boswell for incorporation into her schedules.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO ANNUALIZE REVENUES FOR CUSTOMER GROWTH AND CHANGE IN USAGE.

A. The customer growth adjustment adjusts test period revenues and expenses by an amount that represents the growth in kWh sales due to the change in the number of customers. The adjustment estimates the change in kWh sales the Company would have booked had the end-of-period (EOP) level of customers been served for each of the twelve months of the test period.

The change in usage adjustment adjusts test period revenues and expenses by an amount that represents the difference in kWh usage per customer between each month of the test period and the corresponding month of the update period. The change in usage adjustment estimates the change in kWh sales the Company would have booked had the EOP usage profile per customer been exhibited by the EOP level of customers throughout the test period.

The adjustments are calculated by multiplying the total kWh adjustment by average customer class rates based on annualized revenues divided by per book sales.

Q. HOW DID THE COMPANY ADJUST FOR CUSTOMER GROWTH AND CHANGE IN USAGE AT THE END OF THE TEST PERIOD?

A. For the Residential, Lighting, Traffic Signal, and Building Construction rate classes, DEC used regression analysis to derive equations that best fit historic billing data ending December 31, 2018. The Company fit 12-, 24-, 36- and 48-month data to linear, exponential, power, logarithmic, quadratic, cubic and quartic equations. The equation with the highest adjusted r-square[1] value was used to calculate the representative EOP level of customers for each rate class. The change in the number of customers was determined by taking the difference between the calculated EOP level of customers and the actual bills for each month of the test period. The monthly average usage per customer for each month of the test period was multiplied by the corresponding change in number of customers for each month of the test period, and the results for each month were then summed to produce the total kWh usage adjustment for each customer class. Monthly average usage for the Residential class was weather normalized.

For the General and Industrial customer classes, DEC applied a customer-by-customer approach whereby individual accounts were evaluated to identify customers that established new service or discontinued service during the test period. DEC determined the average monthly usage for each new customer using the months

[1] R-square measures the goodness of fit of the regression equations to the billing data.

during the test period when the customer was on the system, and then multiplied the average usage by the number of months within the test period when the customer was not on the system. The initial month of usage for the new customers was not factored into the average usage calculation. These unrealized kWh sales were added to the adjustment. The kWh usage consumed by lost customers during the test period was removed from the adjustment.

There is no change in usage adjustment at the end of the test period.

Q. DOES THE COMPANY PROPOSE TO EXTEND THE CUSTOMER GROWTH AND CHANGE IN USAGE ADJUSTMENTS BEYOND THE TEST PERIOD?

A. Yes. The Company plans to update the adjustments to reflect customers and usage through January 31, 2020.

Q. DID THE COMPANY PROVIDE THE PUBLIC STAFF WITH AN EXAMPLE OF ITS METHOD FOR EXTENDING THE ADJUSTMENTS?

A. Yes. In a data request response, the Public Staff was provided with workpapers showing the Company's methodology for extending the adjustments, with actual customers and usage from the end of the test period through November 30, 2019 (Extended Period).

Q. PLEASE DESCRIBE DEC'S EXTENDED PERIOD CUSTOMER GROWTH AND CHANGE IN USAGE ADJUSTMENTS.

A. Regression analysis is performed using historical billing data ending November 30, 2019, to establish a new November 2019 EOP level of customers. The kWh adjustment was then calculated by multiplying the monthly per-customer usage for each month of the test period by the difference between the November 2019 EOP level of customers and the December 2018 EOP level.

DEC used the customer-by-customer approach to identify new and lost General and Industrial customers from January 1, 2019, to November 30, 2019. The unrealized kWh sales added to the test period were calculated by determining the average monthly usage for each new customer and multiplying by 12. This added 12 months of unrealized sales to the test period for each new customer at the average usage rate. The kWh usage consumed during the test period for customers lost within the Extended Period was removed.

The change in usage was also determined for the Residential, Lighting, Traffic Signal and Building Construction rate classes for the 11 months of the Extended Period. The adjustment was based on the difference in the monthly average usage per customer between the 11-month period ended November 2018 and the 11-month period ended November 2019. The average usage differences were summed and multiplied by the November 2019 EOP level of customers.

As with the test period adjustments, DEC replaced actual test period sales with weather-normalized sales for the Residential customer class.

The Company did not account for changes in usage for the General and Industrial rate classes.

Q. DO YOU AGREE WITH DEC'S METHOD FOR DETERMINING THE CUSTOMER GROWTH AND CHANGE IN USAGE?

A. Yes, generally, except for the modifications I discuss below. This method for calculating customer growth and change in usage is consistent with the method approved by the Commission for use in the Company's last general rate case.

Q. WHAT MODIFICATIONS DO YOU PROPOSE TO THE END OF TEST PERIOD METHODOLOGY PROPOSED BY DEC?

A. For the General and Industrial customer-by-customer approach, DEC determined the average monthly usage for each new customer using only the months during the test period when the customer was on the system, which could range from one to 11 months. For customers with two or more months of billing data, DEC removed the initial month of service from the usage calculation. I revised this calculation by summing the 12 months of billing data following initial month of service and dividing by 12. I believe including this additional usage data results in a more precise representation of the customer's average monthly usage.

Q. WHAT MODIFICATIONS DO YOU PROPOSE TO CUSTOMER GROWTH AND CHANGE IN USAGE FOR THE EXTENDED PERIOD?

A. For the General and Industrial customer-by-customer approach, DEC determined the average monthly usage for new customers using each month of billing data during the Extended Period including the initial month of service. I revised this by removing the initial month of service from the average usage calculation to avoid using a partial month of usage.

For the change in usage calculations, I removed the basic facilities charge revenues. The increase or decrease in usage estimated by this adjustment would not change the number of bills included in the annualized revenues. This adjustment would therefore not change the revenues produced from basic facilities charges.

For the Lighting rate class, I removed the change in usage revenue adjustment. Lighting accounts are billed on a per-light basis, and revenues for this class would not change due to changes in usage.

To account for other changes in sales not estimated by DEC, I calculated a change in usage adjustment for the General and Industrial rate classes. The adjustment was based on the difference in the monthly average weather-normalized usage per customer between the 11-month period ended November 2018 and the 11-month period ended November 2019. The average usage differences were summed and multiplied by the November 2019 EOP level of customers.

Q. DID YOU CALCULATE ADJUSTMENTS FOR CUSTOMER GROWTH AND CHANGE IN USAGE USING THE PUBLIC STAFF'S PROPOSED METHODOLOGY?

A. Yes. I calculated customer growth and change in usage adjustments through the end of November 2019 to correspond with the update period considered by the Public Staff's Accounting Division.

This resulted in an overall kWh adjustment of 428,881,949 kWh, shown in Saillor Exhibit 3, for a total revenue adjustment of $37,924,087. The revenue adjustments for customer growth and usage, shown in Saillor Exhibits 4 and 5 respectively, were provided to Public Staff witness Boswell for incorporation into her schedules.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

SCOTT J. SAILLOR

I graduated from North Carolina State University with a Bachelor of Science degree in Electrical Engineering. I was employed by the Communications Division of the Public Staff beginning in 1998, where I worked on issues associated with the quality of service offered by telephone and payphone service providers, arbitration proceedings, compliance reporting and certification filings. Since joining the Electric Division in 2011, my responsibilities have focused on the areas of demand side management and energy efficiency measures, renewable portfolio standards compliance, applications for resale of electric service and non-utility generating facilities, and revenue and customer growth analysis.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program	)))	SUPPLEMENTAL TESTIMONY OF SCOTT J. SAILLOR PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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	))))

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

SUPPLEMENTAL TESTIMONY OF SCOTT J. SAILLOR
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 Scott J. Saillor. 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 FILE DIRECT TESTIMONY IN THIS CASE ON FEBRUARY 18, 2020?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to update the weather normalization, customer growth and usage adjustments through January 2020.

Q. DID DEC ACCEPT THE CHANGES RECOMMENDED IN YOUR DIRECT TESTIMONY TO THE COMPANY'S ADJUSTMENTS FOR WEATHER, CUSTOMER GROWTH AND CHANGE IN USAGE?

A. Yes. In rebuttal testimony, DEC Witness Pirro stated that the Company agreed with my proposed modifications.

Q. DO YOU HAVE ANY CHANGES TO DEC'S METHOD FOR UPDATING THE ADJUSTMENTS THROUGH JANUARY 2020?

A. Yes. To find the change in the number of test period bills for the General and Industrial rate classes, DEC multiplied the number of customers as of January 31, 2020 by 12 to get a projected number of bills. DEC then found the difference between the projected number of bills and the actual number of test period bills to determine the change in the number of bills. I instead found the difference between the number of bills added to the test period for new accounts and the number of bills removed from the test period for closed accounts from DEC's customer-by-customer approach for calculating customer growth. This adjusts the change in the number of bills from 63,377 to 10,877 for General and from −495 to −318 for Industrial.

Q. DID YOU CALCULATE FINAL ADJUSTMENTS FOR WEATHER, CUSTOMER GROWTH AND CHANGE IN USAGE THROUGH JANUARY 2020?

A. Yes. My adjustments are summarized in Saillor Exhibits 1 through 5.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MS. DOWNEY: And Madam Chair, at some point Mr. Metz was excused by Order of August 13, 2020. Do you want me to move his testimony in now or do you want to deal with him later since he filed testimony yesterday?

CHAIR MITCHELL: Well, we can go ahead. Ms. Downey, since -- since you're in front of me now, let's go ahead and just get it done.

MS. DOWNEY: Yes, Chair Mitchell. So pursuant to the Commission's Order of August 13th, I would move into evidence the testimony and exhibits Dustin R. Metz filed February 18, 2020, consisting of 19 pages and Appendix A, and his supplemental testimony and exhibits filed March 25, 2020, consisting of 14 pages, Appendix A and one exhibit.

CHAIR MITCHELL: All right. Hearing no objection, that motion is allowed.

MS. DOWNEY: Thank you, Chair Mitchell.

(Whereupon, the prefiled testimony and Appendix A, and prefiled supplemental testimony and Appendix A of Dustin R. Metz were copied into the record as if given orally from the stand.)

(Public Staff Metz Exhibit 1 filed with supplemental testimony was admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

In the Matter of
Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina

DOCKET NO. E-7, SUB 1214

In the Matter of
Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina

TESTIMONY OF
DUSTIN R. METZ
PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1213
AND
DOCKET NO. E-7, SUB 1214

TESTIMONY OF DUSTIN R. METZ
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 Dustin Ray Metz. 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 results of my investigation into Duke Energy Carolinas LLC's (DEC or the Company) request for a general rate increase in this proceeding.

Q. **WHAT WERE YOUR AREAS OF INVESTIGATIVE RESPONSIBILITY IN THIS CASE?**

A. I participated in and contributed to a number of components of the Public Staff's investigation in this case, but I specifically reviewed or supervised the review of the following:

- General capital additions to nuclear, hydro, solar, and certain aspects of the fossil generation fleet, including the following:
  - Dual fuel optionality (DFO) of Cliffside and Belews Creek Steam Stations
  - Lee Nuclear Plant
  - Lee Combined Cycle Plant
  - Allen Steam Station
  - Nuclear emergency supplemental power source
  - Nuclear open phase detection
  - Spent nuclear fuel
  - Woodleaf Solar Facility
- Accelerated retirement of Allen Steam Station Units 4 and 5 and Cliffside Steam Station Unit 5
- Materials and Supplies inventory
- Legal and non-legal invoices related to Outside Services
- E-1, Item 10 NC-1500 Adjustment to levelize nuclear refueling outage costs
- E-1, Item 10 NC-2400 Adjustment to coal inventory

- E-1, Item 10 NC-2800 Adjustment to end of life nuclear costs
- Staffing levels for specific work groups
- Nuclear fuel and labor costs
- Base fuel factor

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR INVESTIGATION IN THIS CASE.

A. I recommend one specific adjustment related to the Belews Creek DFO[1] Project and other general recommendations related to my review that require additional actions by the Company. In addition, I address several general concerns that I have for Commission's consideration.

Capital Additions to Generating Plants

Q. PLEASE DESCRIBE THE SPECIFIC CAPITAL ADDITIONS TO THE COMPANY'S GENERATION FLEET THAT YOU REVIEWED IN THIS CASE.

A. DEC witnesses Immel and Capps, in their prefiled direct testimonies, discussed the addition of approximately $1.1 billion of capital plant investments either placed in service, or expected to be placed in

[1] Dual Fuel Optionality allows a generation asset to operate off two distinct fuel sources. In the case of DEC's Cliffside and Belews Creek Steam Stations, the Company constructed the existing units to burn coal only. DFO conversion allows the units to run on both natural gas and coal in varying quantities.

service by January 31, 2020.[2] As part of the Public Staff's investigation, I looked at multiple aspects of capital spend to evaluate them for reasonableness and prudence, as well as whether the asset or result of the capital investment is used and useful.

My investigation included the following: (1) review of prefiled direct testimony of DEC witnesses Immel and Capps; (2) an audit of specific expenditures (i.e., sampling of specific costs); (3) initial and follow-up discovery; (4) teleconferences between the Company and Public Staff; (5) interviews with Company witnesses and staff, including detailed discussions on specific aspects of certain projects; (6) site visits; and (7) review of the overall projects with Company management.

Belews Creek DFO Project

Q. PLEASE DESCRIBE THE PROPOSED ADJUSTMENT TO THE BELEWS CREEK DFO PROJECT.

A. The Company is seeking recovery in this case of the DFO projects for Cliffside and Belews Creek. My adjustment removes the Company's capital project costs related to Belews Creek DFO of $81,833,786.48 (system) through December 2019**.** I have provided

[2] Direct Testimony of DEC witness Steve Immel, at 6, and Direct Testimony of DEC witness Steven D. Capps, at 6.

this adjustment to Public Staff witness Boswell for incorporation in her schedules.

Q. WHY ARE YOU RECOMMENDING THIS ADJUSTMENT?

A. The Company submitted a supplemental response to a data request from the Public Staff related to capital investments for the DFO projects for Cliffside, Marshall and Belews Creek on January 24, 2020. The Company provided its initial response to the original DFO data request on October 7, 2019, and at that time, only the Cliffside DFO project had been completed and was capable of being economically dispatched. We requested additional details on the projects and associated costs. The Public Staff sent a follow-up data request on the Belews Creek DFO Project to the Company on January 31, 2020 (January 31 data request). The Public Staff is still reviewing the February 7, 2020 response by the Company to the January 31 data request. Based on the Company's responses to the first three questions of the January 31 data request, the Belews Creek DFO project is not commercially operational and not available for economic dispatch to serve customers, and it appears that it is not likely that it will be so prior to the close of the hearing in this proceeding. Listed below are the questions and answers from the first three discovery questions of the January 31 data request:

Question 1:

Please confirm that the Belews Creek DFO project is complete and is now commercially available for both units and can be called on for dispatch.

Company Response:

The Belews Creek Unit 1 project was placed in service. The project is still in the commissioning phase with anticipated release for commercial dispatch approximately April/May of 2020. (emphasis added)

Consistent with the original schedule, the Belews Creek Unit 2 is still under construction and not scheduled for commercial dispatch until spring of 2021. (emphasis added)

Question 2:

Please provide a monthly list, from November 2019 to January 30, 2020, of total natural gas consumed.

Company Response:

Please see the table below for total natural gas consumed at Belews Creek from November 2019 through January 31, 2020.

Belews Creek DFO

Month	Total NG Burned (in Dths)
November-19	192
December-19	72,977
January-20	222,734

Belews Creek remains in testing mode. The Company will implement the monthly report when the unit is commercial. (emphasis added)

Question 3:

Provide the expected and achieved heat rate while running in the natural gas mode.

a. If any deviation greater than 5% was observed in actual vs. expected heat rate, please provide a narrative that explains the deviation and factors that contributed to it.

Company Response:

The actual heat rate has not been determined yet as commissioning is not complete.

The remaining discovery questions relate to the specifics of the project (i.e., costs, invoices, project management, etc.) and are still being reviewed; however, they have no bearing on my disallowance recommendation.

Specifically, I recommend the Belews Creek DFO project costs be disallowed in this case because the project is not commercially operational, is unlikely to be prior to the close of the hearing in this case, and, is not used and useful in providing utility service to customers. The Company's data responses reveal that Unit 1 is still in a testing phase and is not expected to be released for commercial dispatch until April or May of this year. Release for commercial dispatch is dependent on no other issues found during the testing and commissioning phase, meaning the actual commercial operation date for Unit 1 is unknown at this time. Unit 2 is still under construction and will not be commercially available before spring of 2021 at the earliest.

Other Areas of Concern Regarding Generating Plant Additions

Q. WHAT OTHER AREAS DID YOU IDENTIFY IN YOUR INVESTIGATION THAT YOU WISH TO HIGHLIGHT FOR THE COMMISSION?

A. I believe it is important for the Public Staff and the Commission to be able to evaluate the soundness of the Company's decisions to make significant capital investments in its electrical system that is both aging and expanding. For example, coal and nuclear generation assets are nearing the end of their useful lives. As an asset approaches the end of its useful remaining life, less time is available for continued capital investments to prove cost-effective for ratepayers. It is important to understand the cost impacts of both individual and multiple projects on both a capacity and energy basis.

Faced with a dynamic landscape of technological and regulatory changes, utilities must balance the operation of the electrical grid with the contemporaneous requirement of meeting supply and demand requirements in real time. These dual requirements affect the decision whether to retire a generation asset and build a new asset or invest capital to prolong the life of the existing generation asset.

Q. CAN YOU PROVIDE ANY EXAMPLES IN THIS CURRENT RATE CASE THAT ARE ILLUSTRATIVE?

A. Yes. One example is the Company's conversion of Cliffside Unit 5 to operate in a dual fuel mode (e.g., coal and natural gas), or DFO. The result of the Company's cost effectiveness evaluation (or equivalent economic evaluation designation) made at the time it made the decision to make the investment found it was reasonable to proceed with DFO, given the expected remaining life of the unit and the expected fuel cost savings.[3] Cliffside Unit 5, at the time of the business decision to proceed with the DFO investment, had a projected retirement date of 2032. However, in this case, the Company requests to be able to shorten the retirement date to 2026. As a result, ratepayers now have six years fewer to reap benefits from the DFO capital investment, but are still responsible for full cost recovery of the investment.

Another example is DEC's Oconee Nuclear Station (Oconee), a three unit generating plant with a current retirement timeframe of 2033-2034.[4] Oconee has a total combined nameplate capacity of approximately 2,600 MW and operates at an average annual

[3] I reviewed the cost analysis and found no material issues with the methodology and calculation.

[4] Oconee Units 1 and 2 are scheduled for retirement in 2033; Unit 3 is scheduled for retirement in 2034.

capacity factor in excess of 90%. The Company has indicated that it is moving forward with evaluation and potential submittal of a second license renewal (SLR). An approved SLR would allow the Company to operate Oconee for up to an additional 20 years, for a total operating life of 80 years for each of the units. As the Company evaluates current capital projects for the current expected operating life through 2033-2034, as well as additional capital costs for a 20 year SLR, such costs should be evaluated on the cost effectiveness of continued plant operation and the resulting increase (or decrease) of both capacity and energy costs (kW and kWh costs, respectively). It is also important to note that if the SLR is granted, while the units will be certified to operate up to an additional 20 years, 20 years of additional operation is not guaranteed.

Also, at this point in time, the economics of evaluating whether obtaining an SLR is cost effective should be completed on a plant by plant basis and not on a portfolio basis. Absent an established carbon policy or a solidified plan on carbon reduction goals, cost estimations and sensitivities require a high degree of speculation. To the extent that the economics support SLR, then the Public Staff would encourage continued operation of the plants as it is in ratepayer interest. Ultimately, if the generation output of older plants can be replaced with more economical resources, then older, less economical plants should be retired at their current license expiration date.

While the Public Staff agrees that the Company must operate its nuclear fleet in a safe manner while meeting all regulatory compliance requirements, it must also make sound capital investments, and those investments should be benchmarked and evaluated with results available for audit and verification by the Commission and Public Staff. This is also true for all generation assets in the Company's fleet and is not just specific to nuclear generation.

Q. DO YOU HAVE ANY OTHER CONCERNS RELATED TO DEC'S CAPITAL EXPENDITURES INCLUDED FOR COST RECOVERY IN THIS CASE?

A. Overall, in this rate case, the Company did respond to the Public Staff's data requests. The Public Staff and the Company worked together on some of the data requests to narrow the scope of the request and to lengthen the time for the Company to respond. However, there were certain instances that required multiple follow-up data requests, telephone conferences, and face-to-face meetings before receiving a complete response. This process made it difficult to complete our investigation of the Company's capital project costs in time to file our testimony.

Q. DO YOU HAVE ANY RECOMMENDATIONS BASED ON THIS CONCERN?

A. Yes. As I stated above, the Public Staff and Commission must be able to fully evaluate the Company's decisions to make significant capital investments in its electric system, including the consideration of alternative investments considered and not chosen. The Public Staff recommends that the Commission order the Company to begin collaboration with the Public Staff within three months following conclusion of the rate case, ton modifications to internal Company policies and procedures that clarify the expectations for project evaluation and selection and document creation and retention. This will enable both the Company and Public Staff to be more efficient in requesting and reviewing project specific documentation going forward.

At this time, I am not proposing specific recommendations or changes to Company procedures as I believe a collaborative effort will better enable the Company and Public Staff to identify the issues and craft solutions to address project evaluation and documentation concerns going forward. This will also ensure that Public Staff recommendations do not unintentionally impose unwarranted costs to ratepayers without providing a commensurate benefit. Finally, I will note that resolving these issues as soon as possible following the rate case conclusion will ensure we do not encounter similar issues with projects going forward.

Q. IN HIS TESTIMONY, COMPANY WITNESS DEMAY STATES THAT THE COMPANY IS ACTIVELY WORKING TOWARDS ACHIEVING A LOWER CARBON FUTURE. AT THE TIME THAT DEC FILED ITS RATE CASE SEEKING RECOVERY OF CAPITAL INVESTMENTS, HAD THE COMPANY ANNOUNCED ITS CORPORATE NET CARBON GOAL, OR HAD THE NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY (NCDEQ) ISSUED ITS DRAFT OF THE CARBON REDUCTION PLAN?

A. While I do not have the exact percentage of projects that were planned and completed since Duke Energy Corporation (Duke) made its initial public announcement of a net carbon reduction goal in the summer of 2019, large capital projects of this nature take many years to plan, achieve funding approval, procure long lead time equipment, manage, construct, and commission. It is likely that the majority of these capital projects in question were approved by management well in advance of Duke's 2019 net carbon goals public announcement. NC DEQ issued their report in the fall of 2019, but the specifics to meet a recommended target have not been fully vetted nor developed. At this time, the DEQ stakeholder process is still ongoing and subject to continued stakeholder input; the exact plan for the electric utilities has not been solidified.

Q. HAS THE PUBLIC STAFF REVIEWED DUKE'S PROPOSED NET CARBON GOALS OR PLANS TO ACHIEVE SAID GOALS?

A. No. As of this date, DEC has not released a plan for achieving those goals.

Accelerated Retirement of Coal Plants

Q. DID THE COMPANY REQUEST TO ACCELERATE RETIREMENT OF CERTAIN COAL-FIRED GENERATION UNITS?

A. Yes. In this rate case, DEC indicated that it plans to retire the Allen Steam Plant in 2024 and Cliffside Unit 5 in 2026. These retirement dates are earlier than shown in DEC's 2018 Integrated Resource Plan (IRP)[5] and 2019 Update[6] filed on September 3, 2019 (less than a month before it filed the general rate case).

Q. DO YOU BELIEVE THAT A GENERAL RATE CASE IS THE MOST APPROPRIATE PROCEEDING FOR EVALUATING EARLY RETIREMENTS?

A. No. The Company's Integrated Resource Plan (IRP) proceeding is the appropriate venue for a thorough review of early, or any,

[5] Docket No. E-100, Sub 157.

[6] Ibid.

generation retirements. The IRP optimizes future generation additions and minimizes production costs across a robust variety of portfolios generated by the Company's capacity expansion model. The IRP modeling process seeks the optimal expansion plan for meeting customer needs given the load, planned unit retirements and uprates, inputs to the electrical system, and imposed constraints. While the IRP does not solely focus on the economics of retiring an asset early, it does evaluate various scenarios in more detail than is possible in the context of a general rate case.

Additionally, the decision to retire a generating asset requires an analysis of power flows and transmission impacts to the electrical system. This analysis should incorporate required or deferred transmission-related costs, replacement generation, load growth projections, and other system impacts.

Q. DO YOU AGREE WITH THE COMPANY'S DECISIONS TO ACCELERATE THE RETIREMENT OF THE ALLEN PLANT AND CLIFFSIDE UNIT 5?

A. Based upon the information available in this case, as well as discussions with Company subject matter experts (SME), the Public Staff believes that no technical or physical constraints prevent the Allen Plant and Cliffside Unit 5 from retiring at the dates DEC proposed in this rate case. While older coal-fired plants are less economical to operate than newer and more efficient generation assets, there are additional costs, other than decommissioning costs, to retire a generation unit. For example, there are interdependencies between the Allen Plant and the electrical grid. Based on multiple discussions with Company SMEs, significant modifications to the substation and switchyard must be completed prior to retirement of Allen. It is my understanding that these modifications will address thermal constraints and allow for operational flexibility in the surrounding area, and are on track to be completed before the proposed plant retirement.

While I do not take issue with the accelerated retirements in this case, I do recommend that the Commission deny any future requests for accelerated retirements in a general rate case and find that retirement dates should be evaluated in the Company's IRP filings where the complexities can be more appropriately and thoroughly evaluated.

Materials and Supplies Inventory

Q. YOU STATED EARLIER THAT YOU REVIEWED MATERIALS AND SUPPLIES. DO YOU HAVE ANY RECOMMENDATIONS BASED ON YOUR REVIEW?

A. Yes. I recommend that the Company have an independent third party perform a review and audit of the Company's nuclear, fossil, and hydro materials and supplies (M&S) inventory and program controls. While I do not recommend disallowance based on my investigation, there is value to continuing self-improvement. In discovery, the Company stated that it has not planned any inventory audits for calendar years 2020 and 2021, and no audits have been performed since the last rate case. I recommend that the Company complete an independent audit of M&S inventory for at least one nuclear station, one fossil station, and one hydro station by the time of its next general rate case filing, or within the next three years, whichever is sooner, and establish a long term schedule for a continuous independent audit cycle (e.g. a three to five year rotational cycle).

Coal Inventory

Q. WHAT IS THE COMPANY'S PROPOSED COAL INVENTORY ADJUSTMENT IN THIS CASE?

A. The Company's proposed adjustment for coal inventory, is reflected in its Form E-1, Item 10, Adjustment NC-2400, establishing the coal inventory balance at 35 days of 100 percent full load burn.

Q. PLEASE DEFINE THE PHRASE "FULL LOAD BURN".

A. "Full load burn" (FLB) refers to the physical quantity of coal needed for full generation output for each facility for a continuous 24-hour period. The aggregate FLB of each plant is the total quantity of coal inventory requested by DEC in its proposed adjustment. FLB is a common designation to quantify coal inventory on hand. This designation helps to evaluate the inventory available during critical demand periods on the utility's system (e.g., extreme weather periods in winter and summer months) to ensure that the Company can meet resupply constraints associated with delivery of the coal inventory.

Q. DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S REQUEST?

A. No. During the last rate case, the Commission approved a provision of the stipulation between the Company and the Public Staff requiring a study to evaluate the appropriate inventory. The Company's requested inventory adjustment aligns with the findings of the study.

<u>Base Fuel Factor</u>

Q. DID YOU REVIEW THE BASE FUEL FACTOR PROPOSED BY THE COMPANY?

A. Yes. The base fuel factor is appropriate and aligns with the Company's proposed and Commission approved previous annual fuel filing, Docket No. E-7, Sub 1190.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I am currently enrolled at North Carolina State University, working toward a Masters of Engineering degree.

I have over twelve years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion and an additional six years of employment with an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on general rate cases, fuel cases, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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 Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))	SUPPLEMENTAL TESTIMONY OF DUSTIN R. METZ PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1213
AND
DOCKET NO. E-7, SUB 1214

SUPPLEMENTAL TESTIMONY OF DUSTIN R. METZ
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 Dustin Ray Metz. 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. ARE YOU THE SAME DUSTIN METZ WHO FILED TESTIMONY IN THIS DOCKET ON FEBRUARY 18, 2020?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an update on the results of my investigation into Duke Energy Carolinas LLC's (DEC or the Company) request for a general rate increase in this proceeding.

Q. PLEASE SUMMARIZE YOUR SUPPLEMENTAL TESTIMONY.

A. I recommend that the capital costs associated with the Belews Creek Dual Fuel Optionality (DFO) project be included in rate base. In addition, I recommend that the capital costs associated with the Clemson University Combined Heat and Power (CHP) project be removed from rate base at this time. The Public Staff is continuing to investigate the Clemson CHP project and will present any additional findings and recommendations as soon as practicable.

Q. MR. METZ, PLEASE EXPLAIN WHY YOU ARE NOW RECOMMENDING ALLOWANCE OF THE BELEWS CREEK DFO.

A. After filing my initial testimony and reviewing DEC witness Immel's rebuttal testimony regarding the Belews Creek DFO, the Public Staff engaged in additional discovery and discussions with the Company. Based on discovery regarding the generation data and tests that have been completed, I now believe that it is appropriate for the associated costs to be included in rate base. Discovery also revealed that DEC had only included DFO costs associated with Belews Creek Unit 1. Construction is not complete on Belews Creek Unit 2 DFO, and DEC appropriately did not include those costs in rate base in this proceeding. I have notified Public Staff witness Michelle Boswell of this revision to my February 18 testimony.[1]

Q. WHAT IS A CHP FACILITY?

A. A CHP facility utilizes a combustible fuel source (typically natural gas) to generate heat. The heat created through combustion results in energy that is transferred through the generation station to produce work (electricity or power). As with most processes that convert one form of energy to another, it is difficult to achieve one hundred percent conversion efficiency, leading to system losses as a result of thermodynamic properties, friction, and resistance. To increase the overall efficiency of the cycle, one tries to minimize heat loss (waste energy) in order to maximize the heat content utilization of the incoming fuel source.

In a combined cycle plant, this efficiency gain is accomplished by utilizing the waste or “leftover” heat from the combustion turbine (hot combustion gases directly utilized in electricity generation), and transforming this heat into steam via a heat recovery steam generator (HRSG). A steam turbine (utilized in combined cycle

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[1] It should be noted that while the Public Staff agrees that Belews Creek Unit 1 DFO should be included in rate base, the project has been subjected only to limited testing. Significant testing and commissioning activities are still required before full economic dispatchability can be realized.

generation facilities) uses the energy in the steam to produce electricity. Any remaining steam eventually changes back to water and is reused.

A CHP utilizes a similar approach, but instead of a HRSG creating steam to move a steam turbine and generate additional electricity, the steam is sent to an industrial process, where it is utilized for other needs. CHP is not a new concept, but advances in efficiencies and decreased natural gas costs have allowed the technology to become cost competitive in some situations.

Q. PLEASE DESCRIBE THE CLEMSON CHP PROJECT.

A. The Clemson CHP project was placed into service as of December 18, 2019. Based on my preliminary investigation, the Clemson CHP project is or will provide: (1) steam service for the Clemson University[2] campus and (2) electrical service connected to the low voltage side (distribution side) of a transmission to distribution (T/D) substation. The net electrical output of the combustion turbine of the CHP is 13 megawatts (MW), and Clemson University has an approximate peak load of 25 MW. The Company has signed a

[2] Clemson University is located in Clemson, South Carolina. It owns its own campus electrical distribution system, but purchases its electricity needs from DEC. http://www.clemson.edu/

contract to sell the steam to Clemson, which I am attaching as Metz Exhibit 1, Steam Supply and Purchase Agreement (Steam Contract).[3] The Company has also built a new substation as part of a separate project to support the Clemson CHP.

Q. WHAT ARE THE COSTS OF THE CLEMSON CHP PROJECT?

A. The Company is seeking to include approximately $50.3 million (system amount) in rate base in this case for the Clemson CHP project, although the Company has informed the Public Staff that some construction costs have not been fully accounted for as there are still costs not booked/closed to plant. Based on information provided to the Public Staff, the Company estimates the total cost of the project will be approximately $52 million.[4] In addition to the cost of the project, the Company has also spent approximately $10 million on the new substation, which is not part of the Company's $50.3 million request.

[3] https://dms.psc.sc.gov/Attachments/Matter/0bcba62a-4b68-48dd-b466-c677f4006919

[4] The North Carolina retail allocable portion of the Clemson CHP project capital costs is approximately 67%.

Q. WHAT COSTS ARE YOU RECOMMENDING BE EXCLUDED FROM THIS CASE?

A. I am recommending that the $50.3 million be excluded from rate base. I have provided this adjustment to Public Staff witness Boswell.

Q. WHY ARE YOU RECOMMENDING EXCLUSION OF THESE COSTS AT THIS TIME?

A. The total project cost of the project is approximately $4,000 per kilowatt (kW), nearly six times greater than the combustion turbine costs utilized as an input to the Company's avoided cost calculations. When one includes the costs of the substation in the project costs, the per kW cost is approximately $4,800/kW.[5] This per kW cost is approaching the cost of a nuclear plant and far exceeds the per kW cost of combined cycle plants. While the extraordinarily high cost of the project may not solely be grounds for a finding of unreasonableness or imprudence, there are other factors combined with the high cost that lead to my recommending exclusion of the costs, absent additional evidence from the Company.

[5] The new substation in question is related to Clemson's increased capacity needs and a reliability project requested by Clemson University, but was sited in coordination with the current CHP project. While the CHP project is connected at distribution voltage, the substation in question is a T/D substation that would require construction or expansion to interconnect the 13 MW electric generation portion of the Clemson CHP and ultimately tie it into the transmission system.

Other factors leading to my recommendation include the Steam Contract provisions[6] regarding the steam service sale price and the contract term. The steam sale price is significantly lower (by at least 30%) than the steam sale price used to model CHP resources in the Company's 2016 IRP.[7] The revenue from the steam sale should partially offset the high $/kW facility costs, as the steam revenue complements the sale of electricity. Exhibit C of the Steam Contract between the Company and Clemson establishes the payment methodology and calculations. The payment calculations are based on a tiered multiplier; essentially, as Clemson purchases higher amounts of steam, the price per unit of steam is reduced. The tiered multiplier is fixed for the duration (term) of the contract, which is the life of the asset (35 years). The revenue paid by Clemson to the Company will be based on annual production of steam multiplied by the respective tiered multiplier of steam production multiplied by the one year forward annual average NYMEX Henry Hub (HH) strip price of natural gas. In other words, the revenue generated from steam is based neither on the delivered price of natural gas, nor the real-time

[6] *Ibid.*

[7] The price Clemson pays for steam is indexed to the New York Mercantile Exchange Henry Hub price of natural gas, per the CHP contract. I have used DEC's 2019 IRP natural gas price forecast to estimate the price of steam sales to Clemson over the life of the contract. Natural gas forecasts are uncertain, but there is no mechanism in the contract to protect ratepayers from lower than expected natural gas prices (and therefore lower than expected steam sale revenue).

cost of natural gas. Because DEC considers the Clemson CHP to be a system asset, ratepayers will be paying for the real time costs of natural gas (absent hedging) for the generation of electricity from the project. This mismatch or lack of an economic price signal to match steam generation to that of electric dispatch signals, amplifies a broader concern that this project is primarily designed to produce steam and electricity for Clemson University, rather than to produce economically dispatched electricity for the overall DEC system. Also, Clemson University and the Company may exercise an option under the contract to potentially use longer NYMEX HH forwards for two to five years. While this may be a good deal for Clemson, it would further misalign the real time cost of steam and electricity from the steam revenue received from Clemson, exposing DEC's ratepayers to more risk and cost.

Further, the Company has indicated that this unit was placed in service in mid-December 2019, and is "available for economic dispatch." However, due to delays in setting up the steam system, DEC has indicated that Clemson will not be able to receive steam until August 2020, at the earliest. Despite the CHP being available for economic dispatch, DEC indicated that the CHP has not actually been called upon to produce electricity for the grid by DEC's control center. Without steam sales, the CHP is not actually economical to run except maybe in certain high-load situations, making it essentially a peaking facility. Based on the March 17, 2020 teleconference between the Company and the Public Staff, the Company stated that the need for the project was triggered by the Company's 2016 IRP (Docket No. E-100, Sub 147). A review of DEC's 2016 IRP shows CHP resources included beginning in 2018 through 2021 totaling approximately 100MW. Using the Company's embedded assumptions and forecasts in the Load, Capacity and Reserve Table 8-C (Winter LCR Table) I removed all of the approximately 100MW of CHP additions. The overall impact of removing all CHP additions reduced the winter planning reserve in 2021/2022 to 16.86%, just marginally below the Company's planning reserve margin of 17%. In fact, using the same Winter LCR Table, removing the approximately 100MW of CHP resources over the 25 year planning period only reduced the reserve margin to a low of 16.60% in the 2031/2032 winter, and in only five out of the twenty-five years did it fall below 17% (16.60% to 16.99%), with the remaining twenty years being at or above the 17% planning reserve margin. Performing the same exercise on the summer LCR Table 8-D (removing all CHP resources) resulted in similar results, indicating only four out of the twenty- five years falling below the 17% planning reserve margin, with 2033 being the first year in which it fell below 17% (16.2%) and the lowest point being in 2038 (14.97%). Thus, at the time in which the Company sought budget approval and to move forward with the Clemson CHP project, it not needed for planning reserve margin purposes. The Company received management approval to move forward with the Clemson CHP Project in October of 2016, and the Steam Contract was signed by both parties on February 2, 2017, thus, the Company was in full possession of the projected reserve margin information during the time it was making the decision to go forward with the Clemson CHP Project and while it was negotiating the steam contract. Even if the Clemson CHP Project had been necessary to maintain DEC's planning reserve margin, which it was not, the project still needed to be economically viable, least reasonable cost, and prudent, to be in the interest of ratepayers.

Additionally, there are provisions in Exhibit D of the Steam Contract that would allow the parties to terminate the contract. Section 15.1 provides that after the eleventh year of commercial operation of the unit, either party may terminate the contract with a limited penalty of two times the annual steam sale contract value.[8] While the ultimate cost of the convenience termination provision paid by either party is

[8] The example provided in the Steam Contract provides an estimated $1.9M in annual revenue, the total steam output is approximate to what the Company has relayed to the Public Staff to date, and the NYMEX HH price listed was $2.50/MMBTU. In its recent fuel filing in Docket No. E-7, Sub 1228, the Company proposes use of the expected forward Henry Hub price in the billing period of $2.44/MMBtu.

dependent upon the cost of natural gas and the steam produced, there could be a significant amount of revenue that would go uncollected from a loss of steam sales if the termination provision was exercised. This termination provision is especially concerning because ratepayers could be burdened with this cost for 35 years if there is early termination. Further, the project was modeled as a 35-year project, and the cost-benefit analysis would be severely affected by a shortened term.

Also, because of the unique interconnection of this facility into the Clemson distribution system, where the peak loads are greater than the output of the facility, the Clemson CHP is more of a distribution resource. The project is more analogous to a behind-the-meter net metering arrangement that is connected to serve a single South Carolina system retail customer, rather than a system resource. This is especially concerning when North Carolina retail customers are being asked to pay nearly two-thirds of the cost. The only electricity that will reach DEC's transmission system is any excess that is produced beyond Clemson's load.

Additionally, the Company is responsible for the costs associated with continuing maintenance and ongoing capital needs for plant operations (both fixed and variable operations and maintenance (O&M)). Presumably, the Company will be requesting recovery of these costs from ratepayers. These costs will only be partially offset by the revenue generated from the steam sales to Clemson. The Company has indicated to the Public Staff that it anticipates an annual O&M cost of approximately $3.3 million, of which $1.2 million is labor.

The Company has also not provided an explanation or adjustment in its testimony to address the lack of steam sale revenue since the project was placed in service. DEC, at a minimum, should have made a pro forma adjustment to account for anticipated steam sales to Clemson University to offset the future revenue requirement of this facility.

In summary, the Public Staff believes that the costs should be removed from rate base in this case at this time. The project appears to be an uneconomical distribution resource for a sole South Carolina load customer. Given the information known to date, all current and future project costs, inclusive of fuel, O&M, M&S inventory, etc., should be excluded from recovery, or at a minimum, assigned to South Carolina. Should additional discovery[9] reveal additional

[9] The Public Staff has submitted discovery to DEC on the project and expects to receive responses before the hearing in this case.

information that is pertinent to this recommendation, the Public Staff will file additional supplemental testimony.[10]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[10] I was part of the task force that reviewed Duke Energy's plan to build a proposed Duke University CHP. While the Company ultimately withdrew its plans to move forward with that project, the Public Staff had very similar concerns to the ones I have discussed here. One of the significant items identified during the Duke University CHP project review was around the monetization of expected revenues from the steam sale to Duke University.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I am currently enrolled at North Carolina State University, working toward a Masters of Engineering degree.

I have over twelve years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion and an additional six years of employment with an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on general rate cases, fuel cases, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

CHAIR MITCHELL: All right. Any additional -- any additional matters to consider before we begin?

MR. MEHTA: Chair Mitchell, this is Kiran Mehta --

CHAIR MITCHELL: All right, Mr. Mehta.

MR. MEHTA: -- for the Company. If there are no more Intervenors giving testimony, yesterday we had a discussion regarding the joint exhibits, and I think what I would like to do, even before Mr. Hart takes the stand, is to go ahead and move into evidence all the joint exhibits, those would be as premarked, so Joint Exhibits 1 through 13.

CHAIR MITCHELL: Mr. Mehta, just -- it's Joint Exhibits 1 through 14; is that correct?

MR. MEHTA: Thirteen (13). The last one is 13.

CHAIR MITCHELL: Okay. All right. You trailed off there at the end. All right. Mr. Mehta, hearing no objection to your motion, Joint Exhibits Numbers 1 through 13 will be admitted into the record at this time.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, Joint Exhibit Numbers 1 through 13 were identified as premarked and admitted into the record.)

CHAIR MITCHELL: All right. Anything further?

(No response.)

CHAIR MITCHELL: All right. With that, Ms. Force, Ms. Townsend, you may call your witness.

MS. TOWNSEND: Yes, Chair Mitchell. The Attorney General's Office calls Steven Hart. Steve, if you could put on your camera, please. Thank you.

STEVEN C. HART; Having been duly affirmed,

Testified as follows:

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

DIRECT EXAMINATION BY MS. TOWNSEND:

Q Okay. Please state your name for the record.

A My name is Steven, with a V, Hart.

Q All right. And what is your business address?

A It's 2923 South Tryon Street, Suite 100, Charlotte 28203.

Q Thank you. Did you cause to be prefiled in this case on February 18th, 2020, direct testimony consisting of 128 pages and 62 exhibits numbered 1 through 39, 40A through 46A, 40B through 46B, and 47 through 55?

A Yes, I did.

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

A Yes.

Q And have you prepared an errata sheet with those changes?

A Yes, I have.

Q With those corrections, if you were -- if I were to ask you the same questions today, would your answers be the same?

A Yes.

Q All right. And did you also cause to be prefiled in this case on March 4, 2020, supplemental testimony consisting of six pages numbered 126 through 131?

A Yes.

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

A Yes.

Q Have you prepared an errata sheet with those changes?

A Yes, I have.

Q Okay. With those corrections, if I were to ask you the same questions today, would your answers be the same?

A Yes.

Q All right. Mr. Hart, have you done a summary of your testimony?

A Yes, I have.

MS. TOWNSEND: Chair Mitchell, I would request that Mr. Hart's direct and supplemental testimony, the errata sheets regarding same, as well as his Summary be copied into the record as if given orally from the stand, and that his 62 exhibits be identified and marked.

CHAIR MITCHELL: All right. Ms. Townsend, hearing no objection, your motion is allowed.

(Whereupon, the prefiled direct testimony, redacted, as corrected, including unredacted pages, as filed on 2/19/20, supplemental pages 126-131 as filed in the docket, Errata pages, and Summary, were copied into the record as if given orally from the stand.)

(Whereupon, Hart Exhibits 1-55 were identified as premarked. Confidential Hart Exhibits 16-20, and 31-32 were filed under seal.)

February 18, 2020
Direct Testimony of Steven C Hart, PG
Before the North Carolina Utilities Commission
Docket No. E-7, Sub 1214
For NC Attorney General's Office

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS AFFILIATION, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Steven Hart and I am the President and Principal Hydrogeologist of the environmental consulting and engineering firm Hart & Hickman, PC. Hart & Hickman, PC started its business in 1995, has offices in Charlotte and Raleigh, North Carolina, and employs over 60 professionals. My business address is 2923 South Tryon Street, Suite 100, Charlotte, NC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in 1986 from the University of Virginia in Environmental Science with an emphasis in hydrology (the study of surface and subsurface water) and hydrogeology (the study of the occurrence and movement of subsurface water). I received a Master of Science degree in 1989 from Texas A&M University in Geology, specializing in the areas of engineering geology (the study of the impact of geology on engineering structures such as dams) and hydrogeology. I have attended continuing professional education seminars on topics concerning geology, hydrogeology, the fate and transport of contaminants in the environment, site assessment and remediation, and other environmental science principles. I use the term "fate and transport" in my testimony to describe the overall concept of 1) how a contaminant moves in soil, sediment, surface water, and groundwater (i.e., the transport component), and 2) how the contaminant may change once it enters the environment (i.e., the fate component).

Prior to founding H&H, I was employed by the international environmental and engineering consulting firms Environmental Resources Management and Dames & Moore (now AECOM) in Charlotte. I have over 30 years of hands-on experience assessing geologic and hydrogeologic conditions and managing and remediating environmental impacts at sites throughout the United States and in particular in North Carolina and South Carolina. In my professional experience, I have been engaged in all facets of environmental investigation and remediation for various types of compounds including metals and other inorganic compounds, petroleum hydrocarbons, chlorinated hydrocarbons, volatile and semi-volatile organic compounds, pesticides, herbicides, and per- and polyfluoroalkyl substances (PFAS) in soil, sediment, groundwater, and surface water. I have also been directly involved in soil and groundwater remediation design and implementation at a wide variety of sites, and have implemented remedial programs which have utilized such methods as soil (and other solids) removal and treatment, groundwater extraction and treatment, soil vapor extraction, bio-venting, air sparging, in-situ chemical oxidation, enhanced bio-remediation, and natural attenuation. I frequently consult clients on regulatory compliance issues and protection of human health and the environment with regard to soil, sediment, surface water, and groundwater contamination.

Q. WHAT PROFESSIONAL LICENSES AND REGISTRATIONS DO YOU HOLD?

A. I am a Licensed Geologist (LG) or Professional Geologist (PG) in the States of North Carolina, Alabama, Arkansas, Georgia, South Carolina, Tennessee, Texas, Washington, and Wisconsin. I first received professional registration by exam in North Carolina in 1989. In addition, I am a Registered Site Manager (RSM) under the North Carolina Department of Environmental Quality (DEQ) Inactive Hazardous Sites Branch (IHSB) Registered Environmental Consultant (REC) Program. This program was established in 1997 due to limited DEQ resources to address contaminated sites, and it is essentially a privatized regulatory oversight program. In this program a remediating party can hire a REC such as my company Hart & Hickman, PC to perform assessment and remedial actions at a site with limited DEQ oversight, and the RSM certifies that the actions have been performed in accordance with DEQ rules and guidance and to protect human health and the environment.

Q. HAVE YOU BEEN QUALIFIED AS AN EXPERT AND TESTIFIED IN STATE AND FEDERAL COURTS?

A. Yes, I have testified multiple times in State and/or Federal courts in North Carolina, South Carolina, and Arkansas. I have been qualified as an expert in the areas of geology, hydrogeology, fate and transport of contaminants in the environment, contaminant source identification, site assessment and remediation, exposure potential, adequacy of response actions, and remedial methods and costs.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Duke Energy Carolinas (DEC) is seeking recovery of costs in its rates for addressing coal combustion residuals (CCRs), principally related to coal ash basin closure and associated groundwater contamination at eight DEC facilities (Allen, Belews Creek, Buck, Cliffside, Dan River, Marshall, Riverbend, and WS Lee). All of these facilities are located in North Carolina except for the WS Lee plant which is located in South Carolina. As described in Section IV below, coal ash basins were used at each of the DEC facilities for management of CCRs. The CCRs were transported via water (called "sluicing") from the coal-fired power plants to unlined basins where the CCRs were allowed to settle and accumulate over time, and the resultant water was discharged to surface water bodies (lakes or rivers). In addition, multiple other aqueous waste streams from the coal-fired power plants were placed in the coal ash basins such as cleaning wastewaters, landfill leachate, and air pollution control wastewaters.

My testimony focuses primarily on answering the following questions based upon my experience managing environmental contamination in North and South Carolina for over 30 years: First, given the information that DEC knew or that was reasonably discoverable to DEC prior to the adoption of specific regulatory requirements in North Carolina's Coal Ash Management Act (CAMA) and the Environmental Protection Agency's (EPA's) CCR regulations, did DEC undertake reasonable and prudent actions and practices in a timely manner to address storage and disposal of CCR and closure of its coal ash basins before the Dan River release occurred in 2014? Second, how would costs that DEC is seeking for coal ash-related activities likely be different today if DEC had initiated actions sooner to address its ash basin practices?

Q. WHAT INFORMATION DID YOU REVIEW IN PREPARING YOUR TESTIMONY?

A. In preparing my testimony, I reviewed the following information:

- I reviewed the parts of DEC's 2019 Rate Case application and testimony relating to coal ash.
- I was provided access to the Merrill Data site, an online document portal for the DEC 2019 Rate Case, and reviewed data requests related to coal ash basins from the North Carolina Utilities Commission Public Staff, NC Attorney General's Office and other intervenors, and the associated DEC responses to those data requests.
- I was provided access to the Consilio/Relativity online database and performed queries and reviewed various documents in that document portal.
- I reviewed documents provided by the North Carolina Attorney General's Office.
- I reviewed documents obtained through file review requests to the North Carolina Department of Environmental Quality (DEQ) and the South Carolina Department of Health and Environmental Control (DHEC) and documents available on DEQ's online document portal called Laserfiche.

- I reviewed documents obtained from DEQ's website regarding coal ash at the DEC facilities.
- I reviewed documents obtained from Duke Energy's website concerning coal ash.
- I reviewed regulatory and industry publications related to CCRs and coal ash basins.

I recognize that there is a very large volume of documents from these sources regarding CCR and coal ash basins at the DEC facilities. In my review and evaluation, I strived to be thorough but recognize that it is possible that I did not locate some documents that could potentially be relevant to my testimony. However, given the large volume of documents I reviewed, it is unlikely that such additional information would significantly affect my testimony.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I have organized my testimony into sections as follows:

- Section II provides a summary of my testimony which is further described in Sections III through XIII.
- Section III briefly describes rules governing coal ash basins and specifically groundwater contamination from coal ash basins.
- Section IV provides a general history of information about coal ash basins and groundwater contamination.
- Sections V through XII describe specific information about coal ash basins and groundwater contamination at each of the eight DEC facilities.

- Section XIII answers the questions that are the purpose of my testimony based upon an evaluation of the information in Sections II through XII.

II. SUMMARY OF OPINIONS

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony will show the following:

1. The utility industry, including DEC, knew about the potential for contamination of groundwater from coal ash basins as early as the 1980s.
2. At some DEC facilities, groundwater monitoring had been conducted as early as the early 1990s and indicated groundwater contamination issues with coal ash basins.
3. By the early 2000s, as a result of an EPA Regulatory Determination, it was clear to the industry that EPA's documentation of damage cases from coal ash basins and their assessments of environmental impact would lead to increased scrutiny, environmental sampling, and potential closure of ash basins.
4. DEC documents indicated that by 2003, DEC knew about the changing regulatory environment with regard to coal ash basins and that addressing the basins by performing groundwater monitoring and considering dry ash conversions would reduce long term risks and liabilities and identify problems up front, but would also result in increased costs.

5. Despite this internal knowledge, DEC continued to sluice coal ash to some basins until 2018.

6. In addition to sluicing coal ash, DEC introduced other wastewater streams to the basins over time so that the basins became a location to discharge its wastewaters, and it did so in some cases without evidence of how those additional waste streams, such as advanced air pollution control technology wastewaters, would impact the basins and groundwater. In fact, there is evidence that the addition of these wastewaters led to increased groundwater contamination.

7. In 2004 through 2008, DEC implemented voluntary groundwater monitoring at its ash basins as part of the Utility Solid Waste Activities Group (USWAG) effort to address EPA's concern about coal ash basins. In 2004, DEC indicated to DEQ that it wanted to be proactive and address groundwater concerns up front in advance of the USWAG "action plan" (which was issued in 2006) and indicated that groundwater monitoring wells would be installed by 2006. However, implementation of groundwater monitoring was not performed at several DEC facilities until 2008.

8. Even after the groundwater data was collected, DEC did not follow the USWAG action plan about how to respond to groundwater data collection if, after evaluating the data against background, groundwater impacts were detected. The USWAG action plan indicates that, on detecting groundwater impacts, DEC should have worked with the

regulatory agency to further assess conditions and, as needed, develop corrective action programs. Instead, DEC just submitted the data to DEQ without evaluation or responsive action and implied that the data were consistent with background conditions.

9. The detections above 2L Standard exceedances within the compliance boundary at North Carolina DEC facilities or MCLs at the South Carolina DEC facility should have triggered a real evaluation of background conditions, installation of wells at the compliance boundary for the North Carolina facilities, and additional monitoring wells to define the extent of impacts. However, rather than being proactive with regard to groundwater contamination at its coal ash basins, DEC chose to wait until regulatory agencies noted groundwater contamination concerns from DEC's data submittals. Even after wells were installed along compliance boundaries at DEQ's direction in 2011, DEC continued to indicate as late as 2013 that it strongly believed that the iron and manganese exceedances were the result of background concentrations and that these compounds only had secondary MCLs (implying that they were not a concern). However, the actual data did not support the conclusion that the exceedances were consistent with background concentrations. Further, secondary MCLs have no relevance to groundwater standards.

10. It is evident from my analysis that, as a result of groundwater monitoring data and increased concern with groundwater contamination from coal

ash basins, DEC should have taken responsive action sooner and initiated a systematic plan to address its coal ash basins by converting facilities to dry ash handling, eliminating other wastewater streams, closure planning, and evaluating methods to reduce environmental impact while the basins were still operational. This would have required an expenditure of funds earlier, but would have reduced long term risks and liabilities which would have certainly led to lower costs being requested at this time.

11. Duke Energy's stated position in its 2011 position on the EPA's draft CCR rules indicated that it supported groundwater monitoring at facilities, and that any unit not in compliance would need to take corrective action to come into compliance or implement a closure plan. However, Duke Energy's 2011 position did not reflect Duke Energy's record for responsiveness during the earlier period when it was conducting monitoring; i.e., when groundwater contamination was indicated by the voluntary monitoring, Duke Energy failed to take corrective action.

12. In 2013 and 2014, Duke Energy documents acknowledged that DEC did not yet have any approved closure plans and that it had failed to make "reasonable efforts" toward the closure of ash basins.

13. It was not until after the Dan River release in February 2014 that DEC committed, under regulatory pressure, to implement full assessments, closure evaluations, some dry ash handling conversions, and closure

activities on an expedited basis. The expedited response, increased scrutiny, and reduced confidence after the Dan River release certainly led to increased costs.

14. DEC's costs are higher today than they would have been had it undertaken reasonable and prudent actions and practices in a timely manner to address storage and disposal of CCR and closure of its coal ash basins before the Dan River spill occurred in 2014. Among other factors, the accelerated timeframes for action and the requirements for higher cost approaches such as beneficiation and connection of all properties with water supply wells within a 0.5 mile radius of the compliance boundaries to alternate water supply were likely prompted by loss of confidence in DEC after Dan River and DEC's admission to criminal negligence.

III. RULES GOVERNING COAL ASH BASINS

Q. BRIEFLY DESCRIBE THE CATALYST OF NORTH CAROLINA'S 2014 CAMA RULE AND ITS PERTINENT PROVISIONS.

A. DEQ filed four lawsuits in 2013 against DEC alleging violations of North Carolina law regarding unlawful discharges and groundwater contamination at the DEC facilities in North Carolina (as well as Duke Energy Progress coal electric generating facilities in the State). Then, in February 2014, DEC released between approximately 30,000 to 39,000 tons of coal ash and 27 million gallons of coal ash basin water to the Dan River from DEC's Dan River facility as a result of the failure of a stormwater pipe that ran below an ash basin.

On March 12, 2014, Duke Energy announced short- and long-term plans as well as recommendations and strategies for moving forward after the Dan River release in a letter from Ms. Lynn Goode, President and Chief Executive Officer of Duke Energy, to State officials (Hart Exhibit 1). Such plans included closing the Dan River ash basins, removing the coal ash away from the river at Riverbend, converting facilities to dry ash handling (which eliminates the need for wet sluicing and ash basins), and developing a comprehensive coal ash basin strategy.

Subsequently, North Carolina enacted the North Carolina Coal Ash Management Act (CAMA) in August 2014 (Session Law 2014-122[1]). CAMA was amended in June 2015 (Session Law 2015-110[2]) and July 2016 (Session Law 2016-95[3]). In brief, some of the major provisions of CAMA with respect to coal ash basins include the following:

1. A procedure for prioritization of ash basins and timelines for their closure. High risk basins were required to be closed by December 31, 2019, intermediate risk basins were to be closed by December 31, 2024, and low risk basins were to be closed by December 31, 2029. A June 2015 CAMA amendment classified the DEC Dan River and Riverbend facilities as high risk and required ash basin closure by August 1, 2019. The remainder of the DEC facilities were initially classified as

[1] https://www.ncleg.gov/EnactedLegislation/SessionLaws/PDF/2013-2014/SL2014-122.pdf

[2] https://www.ncleg.gov/EnactedLegislation/SessionLaws/PDF/2015-2016/SL2015-110.pdf

[3] https://www.ncleg.gov/EnactedLegislation/SessionLaws/PDF/2015-2016/SL2016-95.pdf

intermediate risk, but were later reclassified as low risk following dam stability evaluations and connection of water supply wells in the area of the facilities to alternate or treated water supplies.

2. Prohibition on the construction of new and expansion of existing ash basins on or after October 1, 2014.

3. Prohibition on discharges of stormwater to ash basins on or after December 31, 2018 for inactive facilities or December 31, 2019 for active facilities.

4. Conversion of facilities to dry fly ash handling by December 31, 2018 and conversion to dry bottom ash handling by December 31, 2019 (or retirement of the facility prior to that time). Dry handling ash refers to handling of ash by means other than using liquids to sluice the ash to basins.

5. Accelerated timelines for submission of groundwater assessment plans (December 31, 2014) and corrective action plans (up to 180 days from submission of corrective action plans) for restoration of groundwater quality.

6. Accelerated timelines to perform receptor surveys (October 1, 2014) to identify water supply wells in the area of the coal ash basins and to provide permanent water supplies for households within a 0.5-mile radius of a compliance boundary of an ash basin (October 15, 2018).

7. Accelerated timelines for identification (by December 31, 2014), permitting, sampling, and possible corrective action for all discharges from coal ash basins including toe drains and groundwater seeps.

Obviously, North Carolina's CAMA rule does not apply to the WS Lee facility in Belton, SC.

On May 14, 2015, DEC pleaded guilty to criminal negligence in Federal Court based on the Dan River release (Hart Exhibits 2 and 3). In addition, DEC pleaded guilty to criminal negligence in the same Federal Court for allowing discharges of contaminated water with elevated levels of arsenic, chromium, cobalt, boron, barium, nickel, strontium, sulfate, iron, manganese and zinc from a coal ash basin at the Riverbend facility into an unpermitted channel which was discharged to the Catawba River from at least November 2012 to December 2014 (Hart Exhibits 2 and 3).

Q. BRIEFLY DECRIBE EPA'S 2015 CCR RULES.

A. The EPA Administrator signed the Disposal of Coal Combustion Residuals (CCRs) from Electric Utilities final rule on December 9, 2014, publishing the rule in the Federal Register (80 FR 21301[4]) on April 17, 2015, with the rule becoming effective on October 14, 2015. There have been subsequent

[4] https://www.federalregister.gov/documents/2015/04/17/2015-00257/hazardous-and-solid-waste-management-system-disposal-of-coal-combustion-residuals-from-electric

amendments to the rule (see 81 FR 51802[5] dated August 5, 2016 and 83 CFR 36435[6] dated July 30, 2018). EPA's 2015 CCR rule includes the following:

- CCRs disposed in landfills and ash basins would continue to be managed as non-hazardous wastes.
- The rule establishes national minimum criteria for existing and new CCR landfills and existing and new CCR surface impoundments and expansions. These criteria include location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements.
- The rule requires existing unlined CCR surface impoundments that are contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, except in limited circumstances.
- The rule requires the closure of any CCR landfill or CCR surface impoundment that cannot meet the applicable performance criteria for location restrictions (such as height above the water table) or structural integrity. Note that all of the DEC facilities had one or more basins which failed to meet the location restriction of being at least 5 feet above the uppermost aquifer.

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[5] https://www.federalregister.gov/documents/2016/08/05/2016-18353/hazardous-and-solid-waste-management-system-disposal-of-coal-combustion-residuals-from-electric

[6] https://www.federalregister.gov/documents/2018/07/30/2018-16262/hazardous-and-solid-waste-management-system-disposal-of-coal-combustion-residuals-from-electric

The ash basins at the Riverbend facility are not covered by the federal CCR rule because the plant stopped producing electricity prior to October 19, 2015.

Q. BRIEFLY DESCRIBE PRIOR EPA RULINGS AND DRAFT RULES APPLICABLE TO CCRs?

A. Although there are several rulings and draft rules that proceeded EPA's 2015 final CCR rule, the primary rulings and draft rules are the 2000 Regulatory Determination regarding CCRs and the June 2010 Proposed Rule for CCRs. These are briefly discussed below.

<u>May 2000 EPA Regulatory Determination</u>

In May 2000, EPA issued a Notice of Regulatory Determination on Wastes from the Combustion of Fossil Fuels (65 FR 32214) which is attached as Hart Exhibit 4. This notice explained EPA's conclusion that CCRs did not warrant regulation as a hazardous waste under subtitle C of the Resource Conservation and Recovery Act (RCRA). However, EPA concluded that CCRs did warrant regulation as a non-hazardous waste under subtitle D of RCRA when they are disposed in landfills or ash basins. The notice indicates that there was adequate evidence at the time that CCRs could pose a risk to human health and the environment if not properly managed, and EPA had concerns due to the fact that adequate controls such as bottom liners in basins and groundwater monitoring may not be in place at many locations. EPA referenced a 1995 study by the Electric Power Research Institute (EPRI) which indicated that 60% of ash basins constructed between 1985 to 1995 had bottom liners, and 26% of all coal ash basins (regardless of construction date) had bottom liners. Bottom liners minimize the potential for leaching of metals and other inorganics from CCRs in ash basins into groundwater by using a physical barrier to separate the ash basin solids and liquids from underlying soil. The EPRI study also indicated that groundwater monitoring was being performed at 65% of all coal ash basins constructed between 1985 and 1995, and that groundwater monitoring was conducted at 38% of all coal ash basins. Therefore, at least some portion of the electric power industry was utilizing bottom liners and groundwater monitoring as early as 1995 regardless of the age of the coal ash basins.

In the 2000 ruling, EPA identified 11 "proven" damage cases from CCRs landfills and ash basins. EPA considered a "proven" damage case to be one where a primary drinking water maximum contaminant level (MCL) had been exceeded in off-site groundwater or surface water. Note that a primary drinking water MCL is used in Federal regulations to determine the suitability of water for drinking based upon health-based criteria. In addition to the eleven "proven" damage cases, EPA also identified 36 additional "potential" damage cases where groundwater impacts above primary MCLs were located under or within close proximity to a landfill or basin and did not extend off-site or where there were exceedances for secondary drinking water MCLs. A secondary drinking water MCL is used in Federal regulations to evaluate the suitability of water for drinking water based upon factors such as taste and odor. Please note that both North Carolina and South Carolina have groundwater regulations and standards that are separate and distinct from Federal drinking water regulations as discussed below in this section.

EPA also expressed concern with the placement of pyrite-containing coal mill rejects in the ash basins because of the potential to generate acidic leachate which could increase the solubility of some metals and lead to a greater potential of groundwater contamination. Pyrite is an iron sulfide mineral and, in the presence of an oxidizing environment, will form sulfuric acid. This is the same process that leads to acid mine drainage at mines.

The 2000 notice indicated that the utility industry, through its trade associations, had indicated a willingness to work with EPA to develop protective management practices (i.e., liners and groundwater monitoring) and some individual companies had committed to upgrading their practices.

June 2010 EPA Proposed Rule for CCRs

In June 2010, EPA proposed rules to regulate CCRs at electric generating plants (75 FR 35128; Hart Exhibit 5), and this proposed rule was the precursor to the 2015 final CCR rule. In the proposed rule, EPA included two options for public consideration to manage CCRs in landfills and impoundments: one in which CCRs would be managed as a hazardous waste under RCRA subtitle C and the other in which CCRs would be managed as non-hazardous waste under RCRA subtitle D. As noted above, in EPA's final 2015 CCR rule, EPA confirmed that CCRs disposed in landfills and impoundments would be managed as non-hazardous wastes.

In the 2010 proposed rule, EPA provided information about the potential for leaching of metals from CCRs. The proposed rule notes that changes to fly ash and CCRs are expected to occur as a result of increased use and application of advanced air pollution control technologies such as flue gas desulfurization (FGD). These advanced air pollution control technologies reduce the amount of metals that are being released to the atmosphere by transferring them to ash and other air pollution control residues.

The proposed rule references a December 2009 report prepared by EPA (Characterization of Coal Combustion Residues from Electric Utilities – Leach and Characterization Data; Hart Exhibit 6) which provides the results of leach tests conducted on CCRs. The results indicated that the upper end of the leachate concentrations exceeded hazardous waste concentrations and/or drinking water levels for the metals antimony, arsenic, barium, boron, cadmium, chromium, lead, molybdenum, selenium, and thallium. The 2009 study further concluded that the leaching potential of CCRs was highly variable and was based upon complex interactions that are particular to the CCR tested and conditions in which leaching occurs.

The proposed ruling also identified additional "proven" and "potential" damage cases that had been identified since the 2000 Regulatory Determination which are summarized in a July 9, 2007 Coal Combustion Waste Damage Assessments (Hart Exhibit 7). In the 2007 report, EPA identified 24 "proven" damage cases (including the 11 identified in the 2000 Regulatory Determination) and 43 potential damage cases (including the 36 identified in the 2000 Regulatory Determination) of groundwater and/or surface water contamination from CCR landfills or impoundments. EPA expressed concern that the number of damage cases was increasing with time. One of the "proven" damage cases cited by EPA was the DEC Belews Creek facility where the discharge of high concentrations of selenium in the 1970s and 1980s from the ash pond to Belews Lake resulted in the elimination of 16 of the 20 fish species in the lake.

The 2010 Proposed Rule also noted that results of additional risk evaluation conducted since the 2000 Regulatory Determination indicated that disposal of CCRs in unlined surface impoundments using wet methods can pose a significant risk to human health and the environment from toxic metals released to groundwater and surface water.

Q. PRIOR TO NORTH CAROLINA'S 2014 CAMA RULE AND EPA'S 2015 CCR RULE, WHAT REGULATORY RULES AND POLICY APPLIED TO GROUNDWATER CONTAMINATION AT COAL ASH BASINS IN NORTH CAROLINA?

A. The North Carolina Administrative Code (NCAC) Title 15A Subchapter 2L Rules apply to all groundwaters in the state. The regulations were initially promulgated in 1979 and have been amended over time. The most recent version of the 2L Rules from 2013 is provided in Hart Exhibit 8. In accordance with NCAC 15A 2L .0103, the 2L regulations are intended to:

> protect the overall high quality of North Carolina's groundwaters to the level established by the standards and to enhance and restore the quality of degraded groundwaters where feasible and necessary to protect human health and the environment, or to ensure their suitability as a future source of drinking water.

The regulations include numerical standards (15A NCAC 2L .0202; referred to as the 2L Standards) which are maximum allowable concentrations resulting from a discharge of contaminants to the land or waters of the state which are intended to protect human health or which would otherwise render the groundwater unsuitable for its intended best usage. Each contaminant has a separate 2L Standard, and most standards are based upon their potential toxicity to humans. Contaminants with lower standards are typically more toxic than those with a higher standard. Standards can change over time as more updated toxicological data becomes available. For example, the 2L Standard for chromium in 1979 was 50 micrograms per liter (µg/L) but was changed to 10 µg/L in 2010 as a result of new toxicity studies showing that this metal warranted a more restrictive standard.

The rules also establish procedures for reporting and corrective action if there are violations of the standards. NCAC 15A 2L .0106 indicates that:

> Where groundwater quality has been degraded, the goal of any required corrective action shall be restoration to the level of the standards, or as closely thereto as is economically and technologically feasible as determined by the Department in accordance with this Rule.

Further, NCAC 2L .0106 indicates that:

> Any person conducting or controlling an activity that results in the discharge of a waste or hazardous substance or oil to the groundwaters of the State, or in proximity thereto, shall take action upon discovery to terminate and control the discharge, mitigate any hazards resulting from exposure to the pollutants and notify the Department..

15A NCAC 2L .0106 also establishes the need to perform initial response actions, site assessment to determine the nature and extent of the contamination, receptor surveys to identify potential receptors of contaminated groundwater, and for proposing and implementing corrective action.

Q. ARE THE 2L STANDARDS THE SAME AS THE FEDERAL DRINKING WATER STANDARDS?

A. No. North Carolina's 2L Standards are separate and distinct from Federal drinking water standards. As noted previously, North Carolina's groundwater rules are intended to protect groundwater resources for future use including potential use as drinking water. The Federal drinking water standards apply to regulated drinking water supplies and include a set of standards called MCLs. In some cases, the North Carolina 2L Standards are more stringent than the Federal MCLs. For example, the North Carolina 2L groundwater standard for benzene is 1µg/L but the Federal drinking water MCL is 5 µg/L.

In addition, the 2L Standards do not include "primary" or "secondary" standards such as the Federal MCLs. As discussed previously, the Federal drinking water MCLs include primary MCLs which are based upon human health and secondary MCLs which are based upon aesthetics. There is no analog to this in the 2L Standards. Although the 2L Standards takes these factors into account, all 2L Standards are "equal" for the sake of compliance with the standards.

Further, just because a compound has a secondary MCL does not mean that it does not pose a risk to human health. For example, manganese does not have a primary MCL but does has a secondary MCL of 50 µg/L which is based primarily on taste and plumbing fixture staining considerations. However, EPA's 2004 Drinking Water Health Advisory for Manganese (Hart Exhibit 9) indicates that adverse health effects from manganese ingestion can occur at concentrations of 300 µg/L.

Q. PLEASE DESCRIBE "REVIEW BOUNDARIES" AND "COMPLIANCE BOUNDARIES" IN THE NORTH CAROLINA TITLE 15A NCAC 2L REGULATIONS AS THEY APPLY TO PERMITTED FACILITIES.

A. In the 2L Rules, there are specific rules that apply to "permitted" facilities. Because the ash basins at the DEC North Carolina facilities were permitted through National Pollutant Discharge Elimination System (NPDES) permits issued by DEQ, the ash basins are considered "permitted" facilities. Based upon my review, it appears that all of the ash basins at the DEC North Carolina facilities were issued NPDES permits on or about 1974. For permitted facilities, the 2L Rules establish "review boundaries" and "compliance boundaries" around permitted waste disposal areas. Note that sections of the 2L Rules addressing compliance and review boundaries were not in the original 1979 2L Rules (*see* Hart Exhibit 10) but were added in the 1989 revisions to the 2L Rules.

NCAC 15A 2L .0107 indicates that for disposal systems individually permitted prior to December 30, 1983, the compliance boundary is established at a horizontal distance of 500 feet from the waste boundary or at the property boundary, whichever is closer to the waste boundary. NCAC 15A 2L .0107(k) indicates that a violation of the 2L Standards within the compliance boundary resulting from activities conducted by the permitted facility must be remedied through clean-up, recovery, containment, or other response when there is an imminent threat to public health or safety or the violation is in the bedrock, unless it can be demonstrated that the violation will not adversely affect or have the potential to affect a water supply well. NCAC 15A 2L .0108 indicates that a review boundary is established around any disposal system midway between the compliance boundary and the waste boundary, and that when the concentration of any substance equals or exceeds the standard at the review boundary as determined by monitoring, the permittee shall take action in accordance with the provisions of NCAC 15A 2L .0106(f) (described below).

The corrective action provisions of the rules at NCAC 15A 2L .0106 (e) indicate that:

> Any person conducting or controlling an activity that is conducted under the authority of a permit initially issued by the Department prior to December 30, 1983 pursuant to G.S. 143-215.1 or G.S. 130A-294, and that results in an increase in concentration of a substance in excess of the standards at or beyond the compliance boundary specified in the permit, shall:
>
> (1) within 24 hours of discovery of the violation, notify the Department of the activity that has resulted in the increase and the contaminant concentration levels;
>
> (2) respond in accordance with Paragraph (f) of this Rule;
>
> (3) submit a report to the Secretary assessing the cause, significance and extent of the violation; and
>
> (4) implement an approved corrective action plan for restoration of groundwater quality at or beyond the compliance boundary, in accordance with a schedule established by the Secretary…

NCAC 15A .0106(f), which is referenced in the above rules governing compliance boundaries and review boundaries, indicates the following:

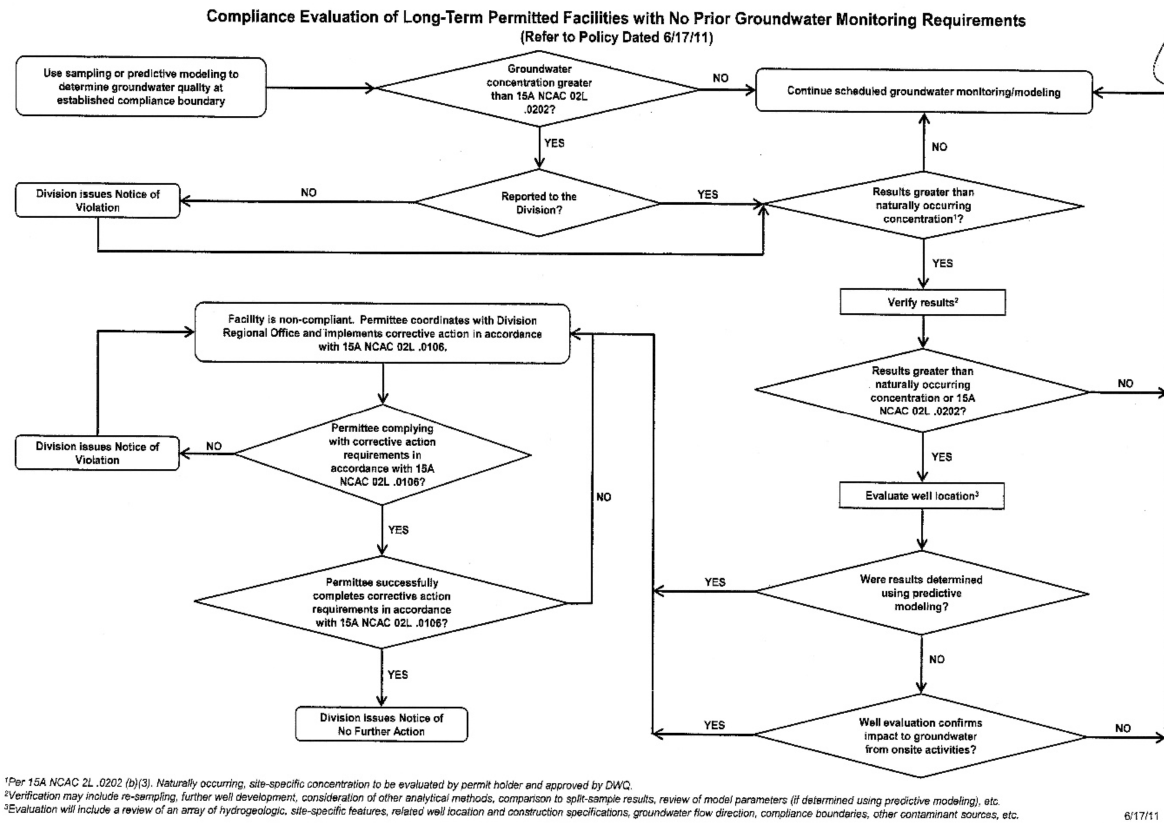
> Initial response required to be conducted prior to or concurrent with the assessment required in Paragraphs (c), (d), or (e) of this Rule shall include:
>
> (1) Prevention of fire, explosion, or the spread of noxious fumes;
>
> (2) Abatement, containment, or control of the migration of contaminants;
>
> (3) Removal, treatment, or control of any primary pollution source such as buried waste, waste stockpiles, or surficial accumulations of free products;
>
> (4) Removal, treatment, or control of secondary pollution sources that would be potential continuing sources of pollutants to the groundwaters, such as contaminated soils and non-aqueous phase liquids. Contaminated soils that threaten the quality of groundwaters shall be treated, contained, or disposed of in accordance with rules in this Chapter and in 15A NCAC 13 applicable to such activities.

Q. DID DEQ ISSUE GUIDANCE TO DEC ON DEQ's POLICIES REGARDING THE 2L RULES AND ITS ASH BASINS?

A. Yes, based upon my review, DEQ issued a letter and a policy regarding the 2L Rules as they applied to permitted facilities in a letter dated December 18, 2009. (Hart Exhibit 11) DEQ indicated in the letter that, based upon a clarification from the Attorney General's Office, facilities permitted prior to December 30, 1983 that have groundwater standard exceedances are subject to the corrective action provisions of NCAC 15A 2L .0106 (*see* Hart Exhibit 8). This correspondence also indicates that, for permitted facilities to determine compliance with the 2L Standards, wells must be placed at or beyond the compliance boundary.

In addition, on June 17, 2011, DEQ issued a "Policy for Compliance Evaluation of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirements" (Hart Exhibit 12).[7] This policy indicates that if permitted facilities have operated for a long period of time and there has not been prior groundwater monitoring, it may be necessary to install wells at the compliance boundary rather that at the review boundary, and that decision is based upon multiple factors including the type of permitted activity, the geology, duration of the permitted activity (the longer a permitted facility has been in operation, the greater potential there is for impact at or beyond the compliance boundary), and the location of the compliance boundary (such as when the property line is closer than the 500 feet). The policy provided a flow chart (provided below) and indicated that if a facility is determined to be non-compliant after the steps outlined in the flowchart, then adherence to the corrective action requirements of NCAC 15A 2L .0106 is required. Following the flow chart below, in simple terms, this indicates that if a facility has concentrations above 2L Standards (and established background levels for naturally occurring compounds) at the compliance boundary, then the facility is non-compliant and should implement corrective action in accordance with 15A NCAC 2L .0106

[7] Note that this policy was rescinded on September 29, 2015 because of the implementation of the CAMA and CCR rules.



A note at the bottom of the flowchart indicates that naturally occurring "background concentrations" are to be determined on a site-specific basis by the permittee and approved by DEQ.

As noted in Sections V through XII below, DEC knew by the 2004 to 2006 timeframe that there were 2L Standard exceedances inside the compliance boundary at multiple facilities, but made no effort to conduct groundwater monitoring at the compliance boundary to determine compliance with the 2L Standards until required to do so by DEQ in 2011. Had DEC conducted monitoring at the compliance boundary earlier, it would have triggered the corrective action requirements of addressing its ash basins much sooner.

Q. WHAT ARE "BACKGROUND CONCENTRATIONS" IN GROUNDWATER AND HOW ARE THEY ADDRESSED IN THE 2L REGULATIONS AND GROUNDWATER CONTAMINATION INVESTIGATIONS IN GENERAL?

A. The primary compounds of concern released from coal ash basins to the environment may also occur naturally. Therefore, the presence of a metal in groundwater may be associated with naturally occurring or "background" concentrations. In some cases, naturally occurring concentrations of compounds can be present in concentrations greater than the 2L Standard for that compound. For that reason, the 2L Standards portion of the Rule at 15A NCAC 2L .0202(b) indicates that, when naturally occurring substances exceed the established standard, the standard shall be the naturally occurring background concentration as determined by the Director (Hart Exhibit 13A).

Q. IN YOUR 30 YEARS' EXPERIENCE, HOW ARE NATURALLY OCCURRING BACKGROUND LEVELS ESTABLISHED FOR METALS AND OTHER INORGANICS IN GROUNDWATER?

A. Naturally occurring background concentrations are established by installing one or more groundwater monitoring wells at locations upgradient and away from both the unit being investigated as well as other known or potential sources of contamination. Otherwise, the measurement of background concentrations will likely be affected by the unit being investigated or by another source and therefore will not be representative of background. For example, if one is trying to determine background concentrations in groundwater at a coal ash basin, installing a well upgradient of the basin but within or downgradient of a coal ash landfill or ash structural fill area would not be an appropriate background location because the landfill or fill area could also be causing groundwater contamination. The background well needs to be installed upgradient of potential sources of contamination.

In addition, background levels need to be established on a site by site basis. As discussed in greater detail below, the presence of metals in groundwater is based upon complex interactions and is dependent upon a number of site-specific factors such as the geology, metals content of the soil or rock, presence of other metals, and the oxidation state of the groundwater. In other words, background concentrations at one facility may be significantly different than those at another location.

Comparison to background concentrations can be performed using a simple direct comparison between the concentrations in a background well or wells and the concentrations in wells located downgradient of a unit. In addition, there are statistical methods that can be used to evaluate if there has been a statistically significant increase in concentrations in a well relative to background.

In my experience, the party addressing the potential groundwater contamination is responsible for making a technically defensible argument as to what the background concentrations are and whether a concentration downgradient of a unit being assessed is consistent with or above background. Although the 2L Standards indicate that background concentrations are "determined by the Director," in practice, a responsible party needs to make a technically defensible evaluation of background and then have DEQ review and concur or disagree with that evaluation. This is consistent with the footnote in the flowchart shown earlier regarding groundwater monitoring at long-term permitted facilities with no prior monitoring. It is also consistent with NCAC 15A 2L .0106 which indicates that, for requests involving approval or termination of corrective action, the responsibility for providing all information required by the rule lies with the person(s) making the request.

Q. WHAT WAS DEC'S APPROACH TO ESTABLISHING BACKGROUND LEVELS AT ITS FACILITIES PRIOR TO CAMA AND THE CCR RULES?

A. DEC initiated voluntary groundwater monitoring between 2004 to 2008 at its facilities as part of a Utility Solid Waste Activities Group (USWAG) program to evaluate groundwater conditions at coal ash basins, as will be discussed in greater detail in Section IV below. In accordance with the 2006 USWAG Utility Industry Action Plan for the Management of Coal Combustion Products (Hart Exhibit 13), at least one background well was to be installed upgradient of a potential source of contamination to evaluate naturally occurring concentrations of metals in groundwater at each site and the data were to evaluated to determine if there was a statistically significant increase. However, the wells installed at Allen, Belews Creek, Cliffside, and Dan River were not suitable for determining background either because they were installed in locations that were upgradient from other sources of contamination or, based upon groundwater flow data, were found to be downgradient of ash basins. No additional background wells were installed at these facilities until 2011 after DEQ identified that some of the DEC "background" wells were not suitable.

In groundwater data submittals to DEQ as part of the voluntary monitoring, DEC indicated that some concentrations identified in the wells at the facilities exceeded the 2L Standards due to background conditions, by reporting that "where naturally occurring substances exceed the generic standards, the appropriate 2L Standard should be the naturally occurring concentration as determined by the Director." However, until 2011, DEC did not have suitable background wells and/or had not done an adequate background evaluation to make that determination at multiple facilities, and the suggestion that the high concentrations were due to background turned out to be invalid and inconsistent with typical background levels in the region. Even in cases where a suitable background well was present at a facility, the data did not support that all of the 2L Standard exceedances were related to background. DEC's determination that many of the detections, particularly for iron and manganese, were related to background conditions were identified in subsequent internal submittals as discussed below.

Q. IF GROUNDWATER CONTAMINATION IS IDENTIFIED WITHIN A REVIEW OR COMPLIANCE BOUNDARY AND THERE IS NO DATA BEYOND THE REVIEW OR COMPLIANCE BOUNDARY, DOES THAT MEAN THAT THERE ARE NO GROUNDWATER

CONTAMINATION CONCERNS ASSOCIATED WITH THE PERMITTED FACILITY?

A. No. Monitoring within the compliance boundary (which includes the review boundary) is intended to provide warning that a groundwater exceedance may be occurring at or beyond the compliance boundary. As noted in DEQ's December 18, 2009 letter to DEC (Hart Exhibit 11), the only way to determine compliance with the 2L Standards is to sample at or beyond the compliance boundary.

Q. IN YOUR EXPERIENCE, IS THE PRESENCE OF GROUNDWATER CONTAMINATION WITHIN A COMPLIANCE BOUNDARY A CONCERN THAT WARRANTS ADDITIONAL EVALUATION?

A. Yes. To the extent that monitoring is done within a compliance boundary and groundwater impacts are detected above background and standards, this serves as a warning that there may be impacts at or beyond the compliance boundary. If there are no detections within a compliance boundary above background and standards, then it is reasonable to conclude that there is a low potential for impacts at the compliance boundary. Alternatively, if impacts are identified above background and standards, then additional evaluation should be performed to determine compliance at the compliance boundary. At a minimum, such evaluation might include additional monitoring over several monitoring events to determine concentration trends with time or scientifically valid modeling based upon site-specific information to evaluate the likelihood of contamination migrating beyond the compliance boundary. If the unit being monitored is 1) older (which would allow further migration), 2) the concentrations over time are increasing within the compliance boundary (indicating that the groundwater impacts are likely expanding), 3) the concentrations in the compliance boundary are remaining relatively stable (indicating that a source is still present and is continuing to contribute to groundwater impacts), 4) modeling indicates that concentrations are likely to exceed 2L Standards beyond the compliance boundary, and/or 5) sensitive receptors like surface water bodies or water supply wells are in the area of the impacts, these would be reasons that additional sampling at the compliance boundary should occur.

Q. PRIOR TO EPA'S 2015 CCR RULE, WHAT REGULATORY RULES AND POLICY APPLIED TO GROUNDWATER CONTAMINATION AT COAL ASH BASINS IN SOUTH CAROLINA?

A. South Carolina's rules for groundwater protection are provided in Regulation 61-68 Water Classifications and Standards. These rules were initially promulgated in 1981 and have been amended over time. The most recent version of the rules is provided as Hart Exhibit 14. As indicated in R. 61-68 H., the intent of the rules is to maintain the quality of groundwaters in South Carolina consistent with their highest use. All groundwaters in South Carolina are classified as underground sources of drinking water unless otherwise classified, and the Department of Health and Environmental Control (DHEC) may require the owner or operator of a contaminated site to restore the water quality to a level that maintains and supports the existing classification and uses.

R. 61-68 H.9. establishes standards for groundwater which are the MCLs set forth in the state's drinking water regulations at R. 61-58. The state drinking water MCLs are the same as the Federal MCLs. There is no analogous concept to the North Carolina 2L rules regarding a compliance boundary or review boundary to determine compliance with the standards for permitted waste disposal units such as coal ash basins. Therefore, a concentration above the MCL is considered an exceedance of the groundwater standard regardless of its distance from the waste boundary. Although not explicitly stated in R 61-68, my extensive experience in groundwater contamination investigations in South Carolina is that properly established naturally occurring background concentrations for compounds can also be used to determine compliance with the groundwater standards if the naturally occurring concentration exceeds the MCL.

IV. COAL ASH BASINS AND GROUNDWATER CONTAMINATION

Q. WHAT IS THE PURPOSE OF COAL ASH BASINS AT A COAL-FIRED POWER PLANT?

A. The burning of coal in coal-fired power plants produces several residuals including ash from the burning of the coal. The coal ash consists primarily of what is termed fly ash and bottom ash. Fly ash is a fine ash that is recovered from the flue gas by various means before it is discharged to the atmosphere. Particles that do not escape as fly ash primarily become bottom ash. Bottom ash is agglomerated ash particles that are too large to be carried in the flue gases and fall to the bottom of the furnace.

As the coal ash accumulates, it must be removed from the furnace and the power plant. One method used to manage the coal ash is to carry the ash with water in a process called sluicing to ponds. In the ponds, the coal ash particles settle out and accumulate in the bottom of the pond and the water is discharged to surface water via a NPDES permit.

Over time, the ash in the pond accumulates and reduces the volume of the pond for further ash accumulation. This also reduces the retention time of the water in the pond which is important for ensuring that the ash settles out before discharge. Once a pond reaches near its capacity, the volume of the pond for additional ash can be increased by removing ash from the pond, allowing the water to drain from the ash in a "stacking" area, and then disposing of the dried ash in an on-site or off-site landfill or as on-site of off-site "beneficial fill". In addition, a pond reaching capacity can be expanded (laterally or vertically) or the pond can be closed and a new pond constructed. The need for an ash pond could also be eliminated by converting the facility to dry ash handling (i.e., not using water to transport ash away from the power plant).

Q. WHAT TYPE OF ENVIRONMENTAL CONTAMINATION IS ASSOCIATED WITH COAL ASH BASINS?

A. The primary type of environmental contaminant associated with coal ash basins are metals including, but not limited to, arsenic, boron, cadmium, chromium, selenium, iron, manganese, mercury, and vanadium, and other inorganics such as sulfate and total dissolved solids (TDS). The metals and other inorganics are derived from the coal which is used as a fuel source in the power plants. The coal that is burned in the power plants has metals that are in "naturally occurring" concentrations. After combustion, most of the organic components of the coal are burned off and the resultant ash now has a higher concentration of these metals, most which are toxic. If toxic compounds such as metals are released to the environment and are present in sufficiently high concentrations, they can pose risks to human health as well as ecological receptors. Because coal ash has high concentrations of certain toxic metals and other inorganics, including those listed above, coal ash can pose an environmental concern.

Some examples of my experience with coal ash and metals contamination and management and disposal of CCR are:

- I have and am assisting several clients with assessment of groundwater impacts from permitted coal ash landfills and from locations where coal ash was placed as "beneficial fill".
- I am assisting a client with evaluating environmental liability risks associated with closure of coal-fired power plants including coal ash basins.
- I am assisting clients with assessment and remediation of environmental contamination from metals at industrial facilities including, for example, a large chromium products manufacturer (primary compounds of concern are hexavalent chromium, vanadium, iron, and manganese), a metal salts manufacturing and recycling facility (primary metals of concern are cadmium, cobalt, nickel, and manganese), and a former sodium hydrosulfite manufacturing facility

that at one time placed waste zinc and cadmium sludges into settling basins.

Q. FROM YOUR EXPERIENCE, BRIEFLY DESCRIBE SOME PRIMARY FACTORS CONCERNING THE FATE AND TRANSPORT OF METALS IN THE ENVIRONMENT.

A. The fate and transport of metals in the subsurface environment is complex. Many factors affect metals fate and transport including, but not limited to:

- The concentration and form of the metal. The higher the concentration of a metal, the more likely it is to move through soil and groundwater. In addition, most metals do not occur in their "pure" form in the environment but rather are typically in the form of metal complexes such as metal oxides or metal sulfides, and these metal complexes each have their own solubility which controls their ability to move in the environment. For example, iron in soil under typical conditions complexes with oxygen to form iron oxides which give shallow soils in the Piedmont region of North Carolina their characteristic reddish color. These iron oxides tend to be fairly immobile in the environment. However, other forms of iron such as iron chlorides are more mobile.
- Soil properties such as density, type of soil (i.e., clay versus sand), cation exchange capacity, pH, oxidation-reduction potential, amount of organic matter, and type and amount of other metals, cations, and anions.

- Properties of the groundwater such as rate of movement and hydraulic head distribution. In addition, the same parameters as noted above for soil will also affect the fate and transport of chemicals below the water table.

In general, after a metal is released to the environment, it will accumulate in soil until the capacity of the soil to retain it is exceeded. Once that occurs, the metal becomes mobile. Once a metal becomes mobile, downward vertical migration takes place in the soil above the "water table" until the metal enters the groundwater (unless the contaminant is released directly into the groundwater). The water table is the location below the ground surface where the ground becomes saturated with water (i.e., essentially all of the openings in the soil contain water instead of air). The depth to the water table varies based upon a number of factors but typically occurs within the upper 50 feet of the ground surface in the Piedmont region, with the shallowest depths occurring near surface water bodies and the greatest depths occurring at topographic highs such as hills.

Once in the groundwater, the metal is available for transport both vertically and horizontally with groundwater as the groundwater flows. Groundwater typically flows from upland areas at the top of hills to lower areas near streams. Groundwater discharges to streams in topographic lows and provides the "base" flow that we observe in streams when there is no precipitation. Once a metal becomes soluble and mobile in groundwater, the metal can migrate with groundwater downgradient and potentially impact groundwater "receptors" such as drinking water supply wells and surface waters such as streams and lakes.

Metals do not "degrade" in the environment but may change forms once they are introduced to the environment and, as noted above, different forms of metals may have different mobilities. For example, iron typically occurs in the environment in its oxidized state (i.e., in the presence of oxygen) as ferric iron (Fe^{+3}) which is a solid form and is fairly immobile. However, in the presence of certain contaminants or natural organics, the oxygen in the subsurface will become depleted and the iron will change to its ferrous state (Fe^{+2}) which is soluble and mobile. In groundwater, this reaction typically leads to the presence of higher concentrations of iron dissolved in groundwater. Higher concentrations of a compound in groundwater in turn may lead to further migration of that compound, a higher concentration at a groundwater receptor, and/or greater costs for remediation.

The fate and transport of metals is further complicated at facilities where wastes are being actively or continuously introduced into the environment over time such as coal ash basins. For example, the capacity of a soil below an ash basin to limit migration of a metal may not be exceeded for many years after the basin is placed into service and only then does the metal begin to migrate and impact groundwater. Therefore, although collection and analysis of groundwater samples below or downgradient of a basin may initially indicate that groundwater is not impacted, the groundwater may become impacted over time as the capacity of the soil to retain metals below and downgradient of the basin is reduced over time.

In addition, the wastes introduced to a basin may also change which may also affect the fate and transport of contaminants over time. As an example, discharge of a hydrochloric acid solution into a water-filled basin during a metal cleaning process may lead to lower pH of water in the basin and increased leaching of metals from metal-bearing wastes in the basin. This is turn increases the potential for environmental impact through such mechanisms as 1) direct discharge of higher concentration of metals from a basin to surface water, or 2) migration from the base of the basin into groundwater. Because subsurface conditions and waste characteristics may change with time, the presence and concentration of metals in groundwater may also change with time. That is why at facilities where contaminants are being actively introduced to the environment over time (such as an unlined coal ash basin), it is important to conduct and evaluate groundwater conditions over time so that potential groundwater contamination issues can be identified early and appropriate steps can be taken to mitigate the contamination as soon as possible.

Q. BESIDES COAL ASH, WHAT OTHER WASTE STREAMS OR MATERIALS ARE AND WERE DISPOSED IN THE COAL ASH BASINS OPERATED BY DEC?

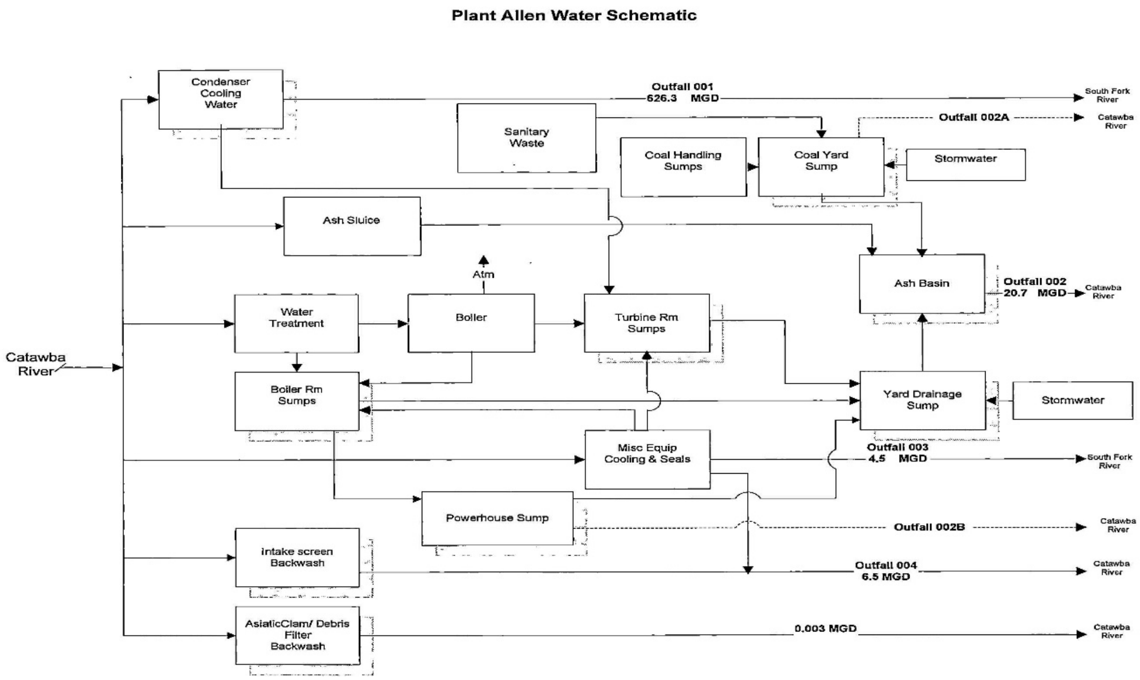
A. In addition to coal ash, many other liquid wastes were disposed by DEC in the ash ponds. A review of NPDES permit applications and permits for the DEC facilities indicates that other than coal ash, the liquid wastes discharged to the ash ponds included, but were not limited to:

- post-septic system domestic wastewater
- wastewater from metal cleaning using chemicals such as acids
- oil storage area runoff
- treated groundwater remediation water (apparently from petroleum remediation incidents)
- coal pile runoff
- plant stormwater
- cooling water
- boiler blowdown
- preheater flush water
- water treatment wastewater
- cooling tower blowdown
- laboratory wastes
- floor drains
- fluidized gas desulfurization (FGD) and other air pollution control systems wastewater
- tank and drum rinse waters
- sumps
- vehicle rinse water
- landfill leachate

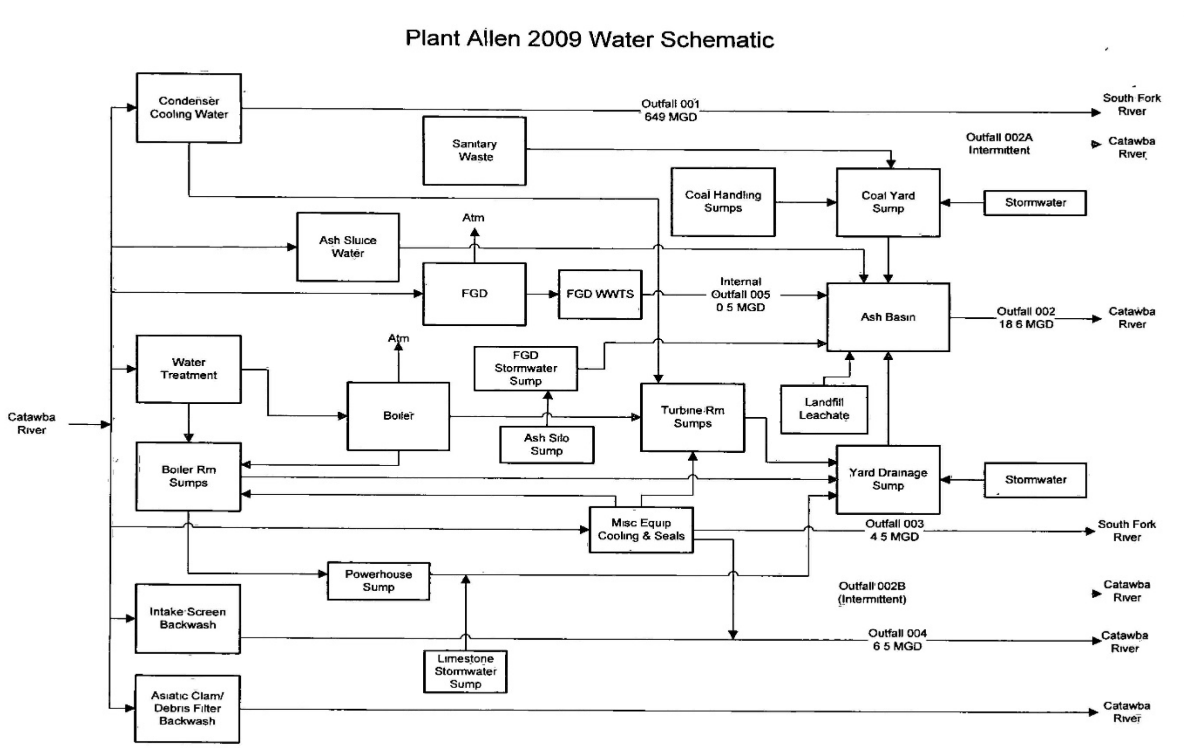
Some of these are considered "low volume" wastes because they enter the pond in fairly low volumes as compared to the higher volume of the ash transport waste. In addition, in some instances, treatment of the water entering the pond was needed to maintain acceptable pH or to reduce metals concentrations in the discharge outfall to the receiving stream water. For example, at the Belews Creek facility, ferric chloride was added to the sluiced water to promote settling of solids to comply with selenium discharge requirements from the basin outfall.

Generally, the number of different wastewater streams increased with time at the DEC facilities, presumably because the ash basins were a convenient location to place wastewaters and there would be considerable dilution of those waste streams in the basins. For example, additional wastewater streams such as landfill leachate from coal ash landfills, treated sanitary wastewater, groundwater remediation system wastewater, and FGD system wastewater were added to the basins over time. For example, a comparison of the process flow diagrams from the 2004 and 2009 NPDES permit applications for the Allen facility is provided below which illustrates such additions.

2004 PERMIT PROCESS FLOWS



2009 PERMIT PROCESS FLOWS



As illustrated, additional wastewater sources including landfill leachate and FGD wastewaters were added to the Allen ash basin between the 2004 permit application and the 2009 permit application.

Q. PLEASE EXPLAIN HOW UNLINED COAL ASH BASINS LEAD TO GROUNDWATER CONTAMINATION.

A. As noted previously, coal ash is sluiced to coal ash ponds from the power plants where it enters the pond along with other process waste streams. The coal that is burned in the power plants has metals that are in "naturally occurring" concentrations. After combustion, most of the organic components of the coal are burnt off and the resultant ash now has a higher concentration of those metals. For example, boron in US coal has been measured at concentrations in the range of 1 to 350 milligram per kilogram (mg/kg; also referred to as parts per million or ppm), while boron in ash from US coal has been measured in the range of approximately 30 to 6,500 ppm[8].

The ash in the basin settles to the bottom of the basin and accumulates in the bottom of the basin over time. Because large volumes of water are used for sluicing and for other waste streams that are placed in the pond, and discharge water from the pond is decanted off the top of the pond, the accumulated ash is typically wet. As a result, some metals present in the ash leach out of the ash and enter the dissolved or aqueous phase and become an ash "leachate". Because a hydraulic head is maintained in the pond, the metals-laden water in the pond migrates downward into underlying soil. A study done

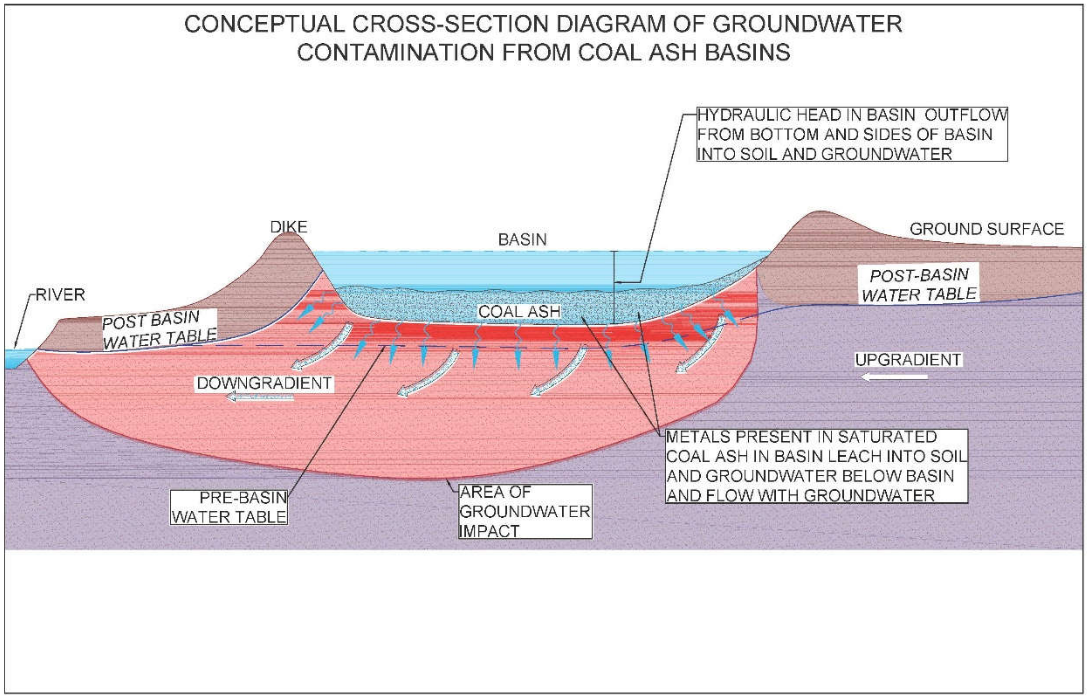
[8] https://nepis.epa.gov/Exe/ZyPDF.cgi/9101C057.PDF?Dockey=9101C057.PDF

in 1991 at an approximate 40-acre ash basin at an electric generating facility in the Piedmont Region of the Southeastern US by the EPRI indicated that there is an estimated discharge from the base of the pond of between 200 million to 450 million gallons per year (Hart Exhibit 15).

All of the DEC facilities are located in the Piedmont Region of North Carolina and South Carolina. If the bottom of the coal ash basin is placed within the water table, the leachate will directly discharge to groundwater. Note that in some cases, because of the large volume of water migrating from the bottom of the pond, the water table may rise in the area of the pond and the bottom of an ash pond that was not in the groundwater table at the time of formation may be below the water table after operation for a period of time.

Attenuation of the metals may occur in the underlying soil and groundwater depending upon the complex processes discussed earlier. Once the capacity of the soil to attenuate a metal exceeds its attenuation capacity, then the metal will enter the underlying soil and may begin to flow with groundwater. Over time, more leachate entering the groundwater system can lead to higher groundwater concentrations and further migration distances in groundwater.

A simplified conceptual diagram of groundwater contamination from a coal ash basin is provided below:



Q. WHAT ARE THE PRIMARY FACTORS THAT CONTRIBUTE TO GROUNDWATER CONTAMINATION FROM UNLINED COAL ASH BASINS?

A. The primary factors that contribute to groundwater contamination from coal ash basins are:

- The mass of ash and concentration of metals and other inorganics that are present in the ash. The greater the amount of ash placed in the basin and the greater the concentration of metals and other inorganics present in the basin, the greater the potential for groundwater contamination.
- The length of time that the basin has been in operation. The longer period of time the basin has been in operation, the greater potential that

the concentration of the metals will increase in the bottom of the basin and the attenuation capacity of the underlying soil will be reduced. In addition, the longer the time the basin has been in operation, the greater the potential for a metal to migrate further with groundwater.

- The hydraulic head within the ash basin. The greater the hydraulic head in the basin, the greater the forces are to drive leachate through the base of the basin and into underlying soil and groundwater.
- The composition of the soil underlying the base. The less organic matter and coarser (i.e., sandier) the material underlying a basin, the greater the potential for groundwater impacts.

Q. WHAT POTENTIAL EFFECTS DO THE PROCESS WASTE STREAMS (I.E., OTHER THAN COAL ASH) DISCHARGED TO COAL ASH BASINS HAVE ON THE BASINS?

A. Other waste streams can have an effect on the complex geochemical interactions within the basins by adding other chemicals, changing pH, etc., and these actions can impact contaminant loading and the fate and transport of other metals and inorganics. For example, a January 13, 2014 Duke Energy "Ash Basin Closure Update" presentation to a Senior Management Committee (Hart Exhibit 16), indicates that FGD scrubber wastewater was creating chloride, bromide, and TDS groundwater issues at Zimmer (Page 44). The Zimmer plant is located in Ohio. Duke Energy's recommendation, as stated in the presentation, was that it close all of the Zimmer plant's active ponds to mitigate impacts of scrubber wastewater (Page 45).

In some instances, Duke Energy sluiced mill rejects containing the mineral pyrite to the ash basins. A study published in 1999 by EPRI entitled "Guidance for Co-management of Mill Rejects at Coal-Fired Power Plants" (Hart Exhibit 17) indicates that pyrite can form acidic leachates (sulfuric acid) as a result of pyrite oxidation in the basins which results in higher concentrations of sulfates, and metals such as iron, nickel, and arsenic. Pyrite is an iron sulfide mineral, and pyrite oxidation is the same process that causes acid mine drainage at older mining facilities. Similarly, the 1991 EPRI study of the Southeastern US power plant coal ash basin referenced previously (Hart Exhibit 15) indicates that oxidation of co-disposed pyrite appeared to be responsible for increased acidity and increased concentrations of iron, nickel, and zinc in the ash basin water.

A May 29, 2007 Duke Energy document entitled "Environmental Management Program for Coal Combustion Products" (Hart Exhibit 18) indicates that pyrites "must be managed in a manner that reduces the potential for oxidation of pyritic material," that "Duke is committed to managing pyrites in a manner identified in the 1991 EPRI study," and advises that pyrites can be best managed by the following methods: co-management with alkaline fly ash in a dry landfill or structural fill, co-management with alkaline fly ash in a surface impoundment completely submerged, or placement on the coal pile for active feeding into the boiler. Although the exact method of placement in the impoundment is not indicated, a Duke Energy document from 2011 entitled "Coal Combustion Products Ten Year Plan" (Hart Exhibit 19) indicates that

DEC was sluicing pyrites to the ash basins at the Allen facility, which appears to be in direct conflict with the advice given in Duke Energy's 2007 document.

Disposal of other wastewater streams also results in additional hydraulic loading to a pond, especially at a facility where there was conversion from wet handling to dry handling of fly ash, resulting in reduced water flows to the pond from that higher volume source. In addition, disposal of non-coal ash wastewater streams complicates and may delay the ultimate closure of the ash basins because a new discharge location must be identified and potential treatment of the wastewater stream discharged to the basin will need to be in place before full closure of the ash basin can occur.

Q. WHEN DO DOCUMENTS YOU REVIEWED INDICATE THAT THE EPA AND THE ELECTRIC INDUSTRY (INCLUDING DEC) WERE GENERALLY AWARE OF THE POTENTIAL FOR LEACHING OF METALS FROM COAL ASH AND ASSOCIATED ACTUAL OR POTENTIAL GROUNDWATER CONTAMINATION?

A. There have been many EPA and electric industry publications regarding potential leaching of metals from fly ash and/or groundwater contamination. I have summarized some select earlier documents below.

March 1980 – Effects of Coal-ash Leachate on Ground Water Quality (Hart Exhibit 20)

In March 1980, EPA and the Tennessee Valley Authority (TVA) published a study of coal ash leachate and groundwater from work performed at two TVA coal-fired facilities. The results of the study indicated that the interstitial water in the pore spaces of the coal ash in basins (i.e., the leachate within the coal ash basin) contained high levels of TDS, boron, iron, manganese, and sulfate and acidic levels of pH as low as 2 (neutral pH is 7). Results of groundwater sampling in the area of the basins indicated elevated levels of TDS, boron, iron, manganese, and sulfate, although at lower concentrations than in the ash basin water which was attributed to attenuation mechanisms in underlying native soil. Figure 28 of the report included a "model" of leachate migration in groundwater from coal ash basins which is reproduced below.

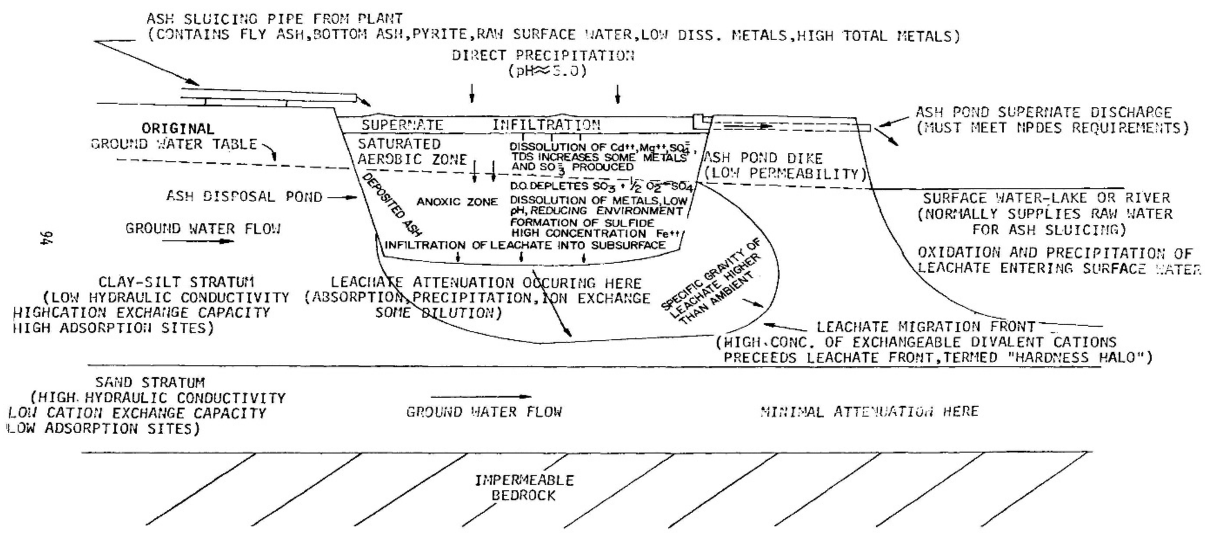


FIGURE 28. SCHEMATIC OF COAL-ASH LEACHATE GENERATION AND ATTENUATION

February 1988 – Report to Congress – Wastes from the Combustion of Coal by Electric Utility Power Plants (Hart Exhibit 21)

In 1988, EPA conducted a study to evaluate the potential adverse effects on human health and the environment from disposal of wastes from the combustion of coal and other fossil fuels. The study was completed to meet the requirements of RCRA which directed the EPA to complete a comprehensive study and report on the health and environmental effects of fly ash and other coal and fossil fuel combustion wastes. In 1978, following the establishment of RCRA in 1976, the EPA recognized that operations generating large volumes of waste such as a utility plant would require different regulations.

The report documents current waste disposal practices on a state by state basis. North Carolina and South Carolina were both listed as having leachate control requirements for solid waste disposal facilities~~,~~; however, North Carolina regulations specifically excluded surface impoundments from the requirement. As such, the surface impoundments were to be regulated by state water laws. According to the EPA research, by 1983, approximately 80% of the utility waste management facilities used some version of a treatment pond and that state and local regulations were making liners and groundwater monitoring a requirement for these types of facilities.

Additional technologies or alternative disposal methods were discussed in the report, including installation of liners or leachate collection and groundwater monitoring. According to the report, lining was becoming a more common practice due to the concern that groundwater contamination may occur from "leaky ponds". Another technology alternative included groundwater monitoring and leachate collection in order to monitor contaminant migration. The suggested practice included groundwater monitoring downgradient of potential source areas, with upgradient wells to determine background concentrations for comparison of naturally occurring metals.

November 1991 – Co-Management of Coal Combustion By-Products and Low-Volume Wastes: A Southeastern Site (Hart Exhibit 15)

In 1991, EPRI conducted a multi-facility study to evaluate the potential effects of management of low volume wastewaters in coal ash basins and one of those facilities was located in the Piedmont Region of the Southeastern US. As noted previously, all of the DEC facilities are located in the Piedmont Region of North or South Carolina. The results of the study indicated that there were statistically significant increases in calcium, magnesium, strontium, and sulfate in downgradient groundwater as compared to upgradient. The report indicated that there were some increases in concentrations of metals in ash basin water which could be associated with other wastewater streams (ex., boiler cleaning) but concluded that the elevated metals in the ash basin water were the result of effects of pyrite oxidation from pyrite mill rejects placed in the pond. The report also indicates that testing indicated low attenuation mechanisms in the Piedmont Region soil below the ash basin through adsorption mechanisms. Adsorption is the process in which a compound like a metal in a liquid state is transferred onto a solid surface like soil.

October 2006 Utility Industry Action Plan for the Management of Coal Combustion Products (Hart Exhibit 13)

In October 2006, the Utility Solid Waste Activities Group (USWAG) issued an "action plan" with regard to management of CCRs. USWAG is an industry group that included over 80 electric utility companies at the time, including DEC. The purpose of the plan was to address concerns raised by EPA in its

2000 Regulatory Determination (discussed previously) as well as subsequent discussions with the industry. USWAG expressed concern that some of the damage cases cited in the 2000 Regulatory Determination did not reflect current industry practices and failed to recognize that even at those facilities where damages were noted, that the involved utilities had acted responsibly to address the environmental issues.

With regard to groundwater, the USWAG action plan included the industry's commitment to adopt groundwater performance standards at facilities that manage CCRs and to implement a comprehensive monitoring program to measure conformance with the groundwater standards at facilities that managed CCRs. The action plan indicates that the goal of the groundwater monitoring program is to yield groundwater samples that will to the extent possible, represent the quality of background groundwater unaffected by CCRs, and to detect CCR-related exceedances of groundwater performance standards. The action plan further indicates that the participating facility owners agree to conduct semi-annual monitoring, agree to determine within a reasonable period of time after completing sampling if there has been a statistically significant increase over background levels, and if monitoring confirms a statistically significant increase over background that exceeds a groundwater performance standard, then the owner would, within 90 days, consult with the appropriate governmental agency and begin to develop a risk-management plan to address contamination. As noted in Sections V through XII below, although DEC did implement voluntary groundwater monitoring at multiple facilities in the 2004 to 2008 timeframe in accordance with the USWAG action plan, DEC did not follow through with the action plan items after receipt of data.

EPRI 2006 Characterization of Field Leachates at Coal Combustion Product Management Sites (Hart Exhibit 22)

In 2006, EPRI published a study that characterized field leachate samples from various coal ash waste management processes. Previous leachate studies had primarily been performed using laboratory leachate testing procedures. The study included the collection and analysis of field leachate samples from various locations and by various methods such as leachate wells, seeps, and the ash/basin interface. The results documented high concentrations of arsenic, selenium, chromium, and mercury in leachate from landfill and surface impoundment samples.

2007 Draft EPA Coal Ash Report (Hart Exhibit 23)

In 2007, the EPA issued a draft report on the human and ecological risk assessment of coal combustion wastes. The report includes an analysis of coal-powered plant waste disposal practices and the potential risks from different site scenarios. Based on the risk pathways evaluated, the EPA concluded that surface impoundments posed the greatest risk for groundwater-to-drinking-water in cases of both unlined and clay lined units. The risk evaluation was based on a conceptual model simulating concentrations at a predetermined receptor. In completed risk assessments for human health, arsenic, boron, lead, cadmium, cobalt, and molybdenum posed potentially unacceptable risks. Surface impoundments were noted to represent a higher risk than landfills due to higher waste leachate concentrations, more unlined units, and the hydraulic head from liquid waste.

<u>December 2009 EPA Characterization of Coal Combustion Residues from Electric Utilities (Hart Exhibit 6)</u>

In 2009, the EPA completed a study to determine the leaching potential of various wastes from coal fired power plants due to changes in air control technologies. Multiple samples of fly ash and FGD gypsum (a byproduct of FGD air pollution control) were collected and analyzed to determine metals in leachate from these waste products. Results of analysis of leachate from the fly ash samples indicated highly variable leaching potential of metals in the samples. However, the upper end of the concentrations exceeded drinking water exposure levels for antimony, arsenic, barium, boron, cadmium, chromium, lead, molybdenum, selenium, and thallium. The report recognized that attenuation of the metals would occur if the leachate were released to the environment.

Q. WHAT DO DEC'S INTERNAL DOCUMENTS YOU REVIEWED INDICATE ABOUT ACTUAL OR POTENTIAL GROUNDWATER CONTAMINATION FROM COAL ASH BASINS AT DEC'S FACILITIES AND DEC'S CONCERNS?

A. Below is a summary of select documents regarding DEC's potential and actual concerns regarding groundwater contamination at coal ash basins. Please note that this is not an exhaustive list of documents but rather select documents over time.

December 1984 – Investigations of Coal Ash Disposal and Its Impact Upon Groundwater (Hart Exhibit 24)

In the early 1980s, Duke Power Company conducted a study on the leaching of metals from coal ash and potential groundwater contamination at the coal ash basins at the Allen plant. EPA performed this later study at the Allen plant as part of a larger study of multiple facilities. The Duke report indicates that the questions of coal ash constituents leaching to groundwater was raised in 1978 in light of increased scrutiny be regulatory agencies. Results of various leach tests reported in the study from samples collected in the early 1980s from multiple DEC facilities indicated relatively higher levels of arsenic (up to 500 µg/L) and selenium (up to 445 µg/L) in most samples although the results from different leach tests were not consistent.

At the Allen plant, results of analysis of a sample of ash basin pore water indicated the presence of arsenic up to 2,425 µg/L. Results of groundwater analyses conducted near the ash basins indicated that concentrations of arsenic (up to 112.5 µg/L versus the 2L standard at the time of 50 µg/L) and selenium (up to 19.5 µg/L versus the 2L standard at the time of 10 µg/L) were detected above standards in two of the wells; however, the groundwater impacts did not extend downgradient from the ponds. The study indicated that there was a leachate plume emanating from the ash basin into groundwater but that the apparent high ion exchange capacity of the underlying soil limited downgradient migration. Figure 4 of the report is presented below and provides a cross-section depicting leachate from the ash pond impacting groundwater:

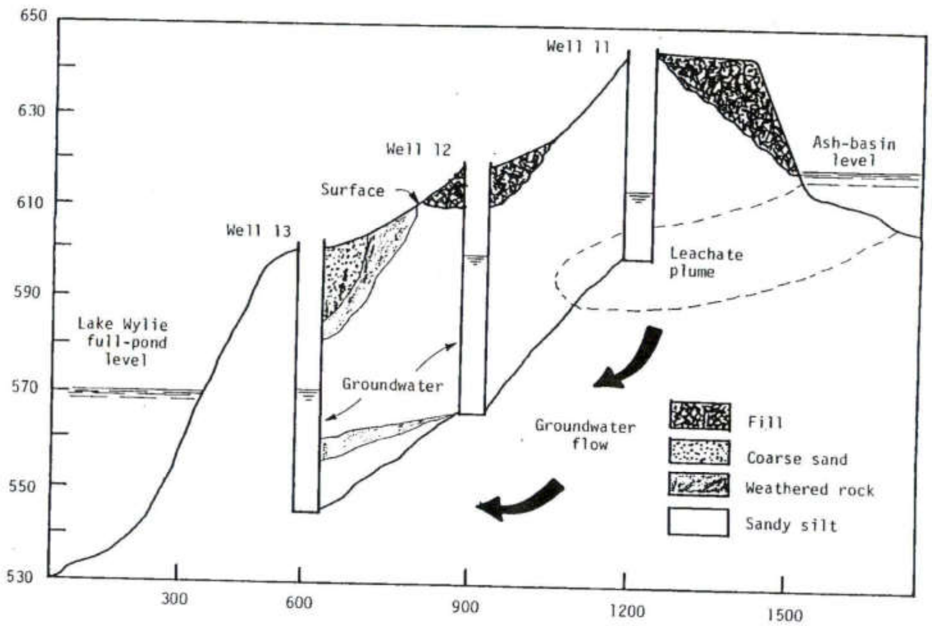


Figure 4. Horizontal movement of leachate plume is tracked over long term using calcium and conductivity data at wells 11, 12, and 13, placed downgrade from basin and each other

<u>February 13, 1997 – Duke Power Letter to Insurance Carriers (Hart Exhibit 25)</u>

In this letter, Duke Power notifies several insurance carriers about potential environmental claims including those related to CCRs that are managed in landfills and impoundments. The letter indicates that at the following facilities, ground water sampling indicates the presence of contaminants above the applicable state cleanup standard: Allen, Belews Creek, Dan River, Marshall, and WS Lee. The letter indicates that the Belews Creek contamination is from a landfill, but there are no other specifics provided regarding the source of the groundwater impacts.

2003 DEC Coal Combustion Products Ten Year Plan (Hart Exhibit 26)

This document presents a plan for storage, disposal, and beneficial use of coal ash and FGD gypsum wastes at DEC facilities. The document indicates that the progressive industry understanding of issues related to CCRs had led to traditional methods of storage and disposal being re-evaluated and that the regulatory environment regarding CCPs was also changing. The report indicates that ash storage practices have the greatest potential for change at that time as compared to any other period in recent history and one of those factors is related to the potential outcome of the new groundwater monitoring process at ash basins (believed to be the USWAG voluntary monitoring described below). As an example, the document points to increased scrutiny of groundwater contamination at Belews Creek between the ash landfill and the ash basin, and the document also notes that DEC's own environmental modeling challenged the previous assumption that groundwater contamination by ash landfills was not likely. That modeling indicated that a cap was needed to avoid groundwater contamination by mercury, selenium sulfate, and cadmium at Belews Creek.

The document indicates that a possible future condition to be evaluated is limited or no sluicing of ash to basins, which would result in significant capital and operations and maintenance costs.

August 18, 2003 Coal Combustion Product Issues Document Presentation (Exhibit 27)

[redacted] **[END CONFIDENTIAL]**

<u>August 12, 2004 email regarding Groundwater Well Installation at Allen Steam Plant (Exhibit 28)</u>

This internal DEC email indicates that DEC personnel met with DEQ to discuss groundwater monitoring well installation at the Allen plant (presumably as part of the USWAG voluntary groundwater discussed above). In the meeting, DEC indicated that it was DEC's intent to be proactive with groundwater monitoring at its unlined ash basins before the entry of an agreement between the utility industry and EPA was reached. DEC indicated in the meeting that monitoring wells would be installed at the Allen and Marshall plants in 2004 and the remainder of the DEC facilities would have monitoring wells installed by 2005 to 2006.

As indicated below, although groundwater monitoring was voluntarily initiated at the Allen Plant in 2004, groundwater monitoring under this program did not start at the other North Carolina facilities until 2006 to 2008.

May 29, 2007 Duke Energy Environmental Management Program for Coal Combustion Products (Exhibit 18)

The stated purpose of this document is to describe the environmental program for management of CCPs. The document indicates that the regulatory environment is becoming increasingly stringent, particularly with regard to groundwater quality standards, and that the chemistry of CCRs is becoming more variable due to changes such as fuel supply and the addition of air pollution control equipment. The report indicates that in 2007 Duke committed to implementing the USWAG voluntary groundwater monitoring plan.

June 27, 2007 Duke Energy presentation entitled "Monthly Technical Manager's Meeting Coal Combustion Products Update" (Exhibit 29)

This document is a slide presentation regarding an overview of the Environmental Management Program for CCRs and the Coal Combustion Products Ten-Year Plan Updates. The document indicates that ash management decisions are becoming more complex and that the risks are becoming more apparent. The noted risks include regulatory compliance risks, environmental impact risk, and public perception risk. The presentation indicates that the following have "changed:"

- Recent ash sampling has revealed that CCR leaching is "worse" than previously assumed
- Changing CCP chemistry with plant modification
- Evolving industry knowledge on ash chemistry
- Changing regulatory requirements

The management program for disposal in ash basins includes the implementation of groundwater monitoring programs, prohibition on dry stacking outside of the ash basin boundary, and requiring use of best technologies for new or expanded facilities and closure. The implications of the ash basin management program concludes the following: more stringent requirements for basins may "drive" the decision to convert to dry handling; basins may need engineered caps or full removal of ash; and additional landfill capacity would be needed for disposal of the removed ash from the basins.

March 2008 Coal Combustion Products Ten Year Plan (Hart Exhibit 30)

With regard to groundwater monitoring, this document indicates that elevated levels of boron and other non-carcinogenic substances have been detected in excess of State groundwater standards in the Carolinas. The document indicates that the most comprehensive solution to the risk of ash basin non-compliance is to convert facilities to dry fly ash handling; however, the report notes that this would be "cost prohibitive" at many of the locations. Costs listed for conversion to dry ash handling range from $11 million at WS Lee to $34 million at Allen, with a note that indicates that dry ash conversion would be installed at Allen by 2009. The document includes an action item to establish an Ash Management to dry ash handling range from $11 million at WS Lee to $34 million at Allen, with a note that indicates that dry ash conversion would be installed at Allen by 2009. The document includes an action item to establish an Ash Management Plan in 2008 to have a "glide path" for closure of ash basins to coincide with planned station retirements.

2009-2011 Duke Energy Draft Coal Combustion Products Ten Year Plans (Hart Exhibits 31, 32, and 19)

In addition to the 2008 Ten Year Plan, I reviewed CCR Ten Year Plans for Duke Energy facilities for the years 2009 through 2011. These documents primarily focus on economic analyses of coal ash management, but also include information about increased focus on environmental concerns associated with CCR management, the proposed federal CCR rules, and the notation that ash basins would likely need to be closed and facilities converted to dry ash handling.

The 2009 Ten Year Plan notes that a bill was introduced in the North Carolina legislature that would require monitoring, corrective action, and phase out of ash basins that were constructed before January 1, 2010.

The documents also indicate that closure of the ash basins is likely to be by in-place closure and capping. The 2011 Ten Year Plan indicates that the "ideal" scenario is to leave the ash basin with as much material in place as possible to provide a "large" cost savings by reducing the costs of grading and importing fill material.

2009 to 2010 Correspondence Between DEC and DEQ Regarding Voluntary Groundwater Monitoring (Hart Exhibits 33, 34, and 11)

As noted previously and as discussed in Sections V through XII below, DEC performed groundwater monitoring at the DEC facilities as part of the USWAG voluntary monitoring program. Monitoring under the program was initiated in 2004 at Allen plant, in 2006 at Buck and Marshall, in 2007 at Belews Creek, and in 2008 at Cliffside, Dan River, and Riverbend. Note that prior monitoring of some wells had been occurring at Belews Creek, Dan River, and WS Lee pursuant to permit requirements. As noted previously, although DEC indicated its intent to be proactive and conduct groundwater well installation in 2004 to 2006 in advance of any agreement between the utility industry and EPA, groundwater monitoring at some facilities did not commence until 2007 to 2008.

In a letter dated March 3, 2009 (Hart Exhibit 33), DEQ indicated that it had been receiving data from DEC as part of the voluntary monitoring program and had noted that data from all seven North Carolina DEC facilities had one or more compounds above 2L Standards. As such, DEQ requested figures of the well locations in relation to waste, review, and compliance boundaries, summaries of all of the data, and an evaluation of groundwater standard exceedances in relation to the boundaries and planned actions as a result of the exceedances in accordance with the corrective action provisions of NCAC 15A 2L .0106. As noted previously, DEC's groundwater data submittals implied that DEC had determined that exceedances of the 2L Standards were the result of reviewing the various groundwater monitoring systems to make them more robust. The letter indicates that "Locating monitoring wells more precisely along the review or compliance boundaries is anticipated."

In a letter dated December 18, 2009 (Hart Exhibit 11), DEQ provided facility-specific evaluations of the data submitted by DEC and requested that DEC put groundwater monitoring wells at the compliance boundaries. DEQ indicated that the wells that DEC had placed inside the compliance boundary were not suitable to determine compliance with the 2L Standards, provided DEC with recommended additional monitoring well locations, and noted issues with some of the existing wells, including DEC-designated background wells.

In a letter dated February 26, 2010 DEC provided the information requested by DEQ including the proposed locations of additional monitoring wells.

March 2011 Duke Energy Position on the Regulation of Surface Impoundments and Landfills Used to Manage Coal Combustion Residues (Hart Exhibit 35)

As noted previously, in 2010, EPA proposed rules for the management of CCRs at coal- fired electric generating facilities. This document indicates the following with regard to Duke Energy's position on the draft CCR Proposed Rule:

- There should be no mandatory phase out of wet handling of CCRs and low volume wastewater streams at basins that meet applicable dam integrity and groundwater performance standards.
- State groundwater performance standards should guide corrective action for CCR landfills and impoundments.

- Groundwater monitoring should be required at all CCR landfills and basins to determine compliance with state groundwater standards and that any unit not in compliance would be required to take appropriate steps to come into compliance or to implement a closure plan.

<u>April 2013 Duke Energy Regulated Utility Operations Environmental Regulatory Issues (Hart Exhibit 36)</u>

This document presents information regarding various regulatory programs that will impact Duke Energy's operations. With regard to "Groundwater Standards and Monitoring," the report indicates that at the Carolinas facilities, elevated levels of boron were detected in some on-site sampling wells in excess of state standards and that "naturally occurring" manganese and iron were also frequently detected. The document also indicates that relatively higher concentrations of boron, TDS, and chlorides in FGD wastewaters being discharged to the ash basins increase the risk of boron and chloride impacts in groundwater and that if groundwater standards are exceeded, a site investigation and corrective action could be required by the regulatory agency. The document also identifies that the ash ponds at the Duke Energy Gibson and Cayuga facilities (in Indiana) are sources of contaminants and have impacted off-site receptors but not at levels above MCLs. The document indicates that these Indiana ponds are in the process of being closed, evaluated, and/or retrofitted with liners.

[redacted] **[END CONFIDENTIAL]**

<u>2013 Ash Basin Closure Strategy (Exhibit 37)</u>

This document is undated, but based on other documents, it appears that this document was drafted in 2013. The document notes the following:

- Capping the basins soon will help begin the process of natural attenuation or other means to reduce constituents in groundwater.
- Ash basin closure has recently seen increased attention and scrutiny and this is only expected to increase while the ash basins have no approved closure plan and "reasonable efforts to close them are not underway".

<u>November 4, 2013 Ash Basin Groundwater Summaries (Hart Exhibit 38)</u>

This Duke Energy document provides a summary of groundwater monitoring data at all Duke Energy facilities including the DEC facilities. This document indicates that there have been exceedances of the groundwater standards at the compliance boundary of all DEC facilities, but none of the DEC facilities have potential receptors. The following identifies the constituents that were in exceedance of the 2L Standards at each DEC facility and indicates what mitigation had been completed to resolve those exceedances:

- Allen: boron, iron, manganese, nickel, and pH/Mitigation: None
- Belews Creek: iron and manganese/Mitigation: None

- Buck: boron, chromium, iron, manganese, sulfate, TDS, and pH/Mitigation: None
- Cliffside: chromium, iron, manganese, sulfate, TDS, and pH/Mitigation: None
- Dan River: antimony, boron, iron, manganese, sulfate, TDS, and pH/ Mitigation: None
- Marshall: iron and manganese, boron, sulfate, TDS, and pH/Mitigation: None
- Riverbend: iron, manganese, and pH/Mitigation: None
- WS Lee: iron, manganese, and pH/Mitigation: None

The document indicates that Duke strongly believes the exceedances for iron, manganese, and pH are from naturally occurring conditions (which is not consistent with actual data as noted in the following sections) and notes that iron, manganese, pH, and TDS "only have secondary MCLs," implying that exceedances of these compounds are not of significance. The MCL standard has no relevance in determining compliance with North Carolina's 2L groundwater standards. As noted above, just because a compound has a secondary MCL does not mean that it does not pose a potential risk to human health and the environment. Based on the level of these exceedances (see below), there was and is a potential risk to human health and the environment.

<u>January 13, 2014 Ash Basin Closure Update Presentation to Senior Management Committee (Hart Exhibit 16)</u>

This document contains presentation slides and slide notes which indicate the following:

- The presentation emphasizes the "[n]eed to be very clear that our coal ash is impacting the groundwater in all locations." A table shows that there have been exceedances of groundwater standards at all of the DEC facilities.
- Mitigation of groundwater impacts generally equates to removing the source and allowing natural attenuation to occur.
- An example at the Duke Energy Asheville station is provided indicating that levels of boron, selenium, and thallium have been decreasing in groundwater since the water level in the pond decreased, and that dewatering is the key driver to improved results.
- An example provided of the DEC Riverbend facility indicates that - with the plant shut down - the flow from the ash pond to groundwater is decreasing and groundwater impacts are improving.
- An example is also provided at the Duke Energy Cayuga facility that is an "advanced" coal ash remediation site. The notes indicate that a new lined pond was installed in 2005 and is the only lined pond at Duke Energy facilities. A voluntary ash pond closure was being coordinated with the state involving cap in place, and groundwater modeling indicates the "dramatic" effect that ash basin dewatering can have on decreasing groundwater impacts quickly.

- The presentation notes indicate that scrutiny will only increase while "reasonable" efforts to close basins are not underway.
- "Internal" recommendations include "aggressively" pursuing closure of ash ponds at all decommissioned sites, closure of all active ash ponds, and the provision of a capital investment program to allow for closure of active ponds and the mitigation of impacts of scrubber wastewater.

Q. AFTER DETERMINATION OF THE PRESENCE OF GROUNDWATER CONTAMINATION, WHAT STEPS CAN BE TAKEN TO MINIMIZE GROUNDWATER CONTAMINATION FROM COAL ASH BASINS?

A. For active basins, steps that can be taken to minimize groundwater contamination from coal ash ponds include reducing the amount of coal ash which is entering the pond by converting the facility to dry fly ash and bottom ash handling (if not done already), removing ash from the basin on a frequent basis, eliminating wastewater streams and hydraulic loading from non-coal ash sources, removing the ash and installing a bottom liner, lowering the water level and/or dewatering the pond to decrease hydraulic loading, and ultimately pond closure. These items all take time to complete, have varying complexities depending upon the specifics of the facility, and all have significant costs associated with them.

Q. DO DOCUMENTS YOU REVIEWED INDICATE THAT DRY ASH HANDLING WAS CONSIDERED PRIOR TO CAMA AND CCR RULES

FOR THE DEC FACILITIES THAT DID NOT ALEADY HAVE DRY ASH HANDLING?

A. Yes, as early as the 2003 Coal Combustion Products Ten Year Plan (Hart Exhibit 26), there are discussions of conversion of facilities to dry ash handling as well as elimination of other wastewater streams to the basins. Although in some cases it is difficult to understand what components DEC considered in different cost estimates, in general, costs increase over time. In the 2003 document, costs for dry ash conversion for the DEC facilities that did not have systems were estimated to be in the range of $11 million to $24 million based upon a system that had been installed at the Marshall plant.

Q. DO DOCUMENTS YOU REVIEWED INDICATE THAT ASH BASIN CLOSURE AT THE DEC FACILITIES WAS CONSIDERED PRIOR TO CAMA AND THE CCR RULE?

A. Yes, in the Duke Energy "2012 Plant Retirement Comprehensive Program Plan" (Hart Exhibit 39), closure of ash ponds is addressed in the context of plant retirement. The document indicates that, over the next several years, Duke Energy would retire designated fossil fuel plants and close ash ponds. The document notes that at non-designated facilities, there is a strategy being considered to transition from wet ash handling to dry ash handling systems.

Q. WHAT EFFECT DID THE RELEASE OF COAL ASH INTO THE DAN RIVER FROM THE DEC DAN RIVER FACILITY HAVE ON HOW IT ADDRESSED ITS COAL ASH BASINS?

A. The 2014 release at Dan River had a significant effect on how DEC addressed its coal ash basins. Although groundwater contamination was identified at each of the facility coal ash ponds and there was an indication that the ponds would need to be closed either because of plant retirement or to address environmental concerns, little action had been taken to address coal pond closure, convert facilities to dry ash handling, or address the contamination. This all changed with the Dan River release. Afterward, DEC committed itself to initiate and/or accelerate these actions as it outlined in its March 12, 2014 letter to State officials (Exhibit 1). CAMA and the CCR rules followed and DEC was no longer able to postpone addressing its coal ash basins.

INTRODUCTION TO SECTIONS V THROUGH XII

The next sections provide a brief, facility-specific summary of coal ash basin groundwater monitoring data at each of the DEC facilities, including an evaluation of when groundwater impacts were identified at each facility, what was known about groundwater conditions at each of the facilities before CAMA and the CCR Rules, an evaluation of how and when DEC developed background concentrations, and a comparison of the data with 2L Standards and background concentrations developed by DEC. The summaries below primarily focus on data collected by DEC prior to the CAMA and CCR rules, but also discuss more recent data particularly as they relate to more recently developed background concentrations.

For ease of reference to the below discussions, figures which depict monitoring wells installed before 2015 are included as Hart Exhibits 40A through 46A for each of the DEC North Carolina facilities except WS Lee. Excel spreadsheets developed by DEC of the groundwater sample analytical data as well as other sampled media such as surface water, soil, and coal ash are included in Hart Exhibits 40B through 46B for each of the DEC North Carolina facilities. The Excel spreadsheets also contain figures of the facilities with all of the sample locations depicted (including post-2015 monitoring well locations).

Further, information regarding each facility was also obtained from the 2019 Environmental Audits in Support of the Court Appointed Monitor provided as in Hart Exhibits 47 through 54.

V. ALLEN STEAM STATION

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The Allen plant historically had two ash basins that received wet sluiced coal ash and other plant wastewaters. The initial ash basin was approximately 100 acres and operated from plant construction in 1957 until 1973 when it reached capacity. The estimated cumulative volume of ash placed in the basin is over 5.1 million cubic yards. This basin is referred to as the retired or inactive ash basin (or RAB). The method of closure of the RAB is not known.

The second ash basin, known as the active ash basin (or AAB) is approximately 170 acres and was initially put into service in 1972. In 2009, the Allen facility converted to dry fly ash handling but continued to sluice bottom ash to the basin. In 2009, DEC also received a permit to construct a landfill on an approximate 30-acre portion of the RAB and this RAB landfill receives dry fly ash ash from the plant. The active ash basin ceased receiving CCRs from the plant in 2019 but will continue to receive plant wastewaters until a new Retention Basin for the other wastewaters is constructed.

The cumulative amount of CCRs disposed in the AAB is approximately 8.7 million cubic yards. In addition to CCRs, the ash basin received such wastewaters as pre-treated domestic wastewater, stormwater from the coal pile area, miscellaneous stormwater flows, a yard drain sump, water treatment filter backwash, metal cleaning waste, treated groundwater, laboratory wastes, floor drain water, metal cleaning wastes, landfill leachate, and FGD wastewaters.

Q: PLEASE DISCUSS WHEN DEC BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

- Groundwater monitoring began at the Allen facility in 2004/2005 and manganese and/or iron were detected in six wells exceeding the 2L Standards. Five of these were installed inside the compliance boundary and one well (AB-01) was installed at the compliance boundary.
- Well AB-01 was installed at the compliance boundary in 2004 and concentrations of iron and manganese were detected above the 2L

Standard. Therefore, groundwater impacts above 2L Standards at the compliance boundary were identified in 2004. This is contrary to DEC indications that there were no 2L exceedances at the compliance boundary as part of the voluntary groundwater monitoring initiated in 2004.

- In its 2010 submittal to DEQ, DEC identified AB-01 as a background well; however, this well is located crossgradient to downgradient of the ash basin waste boundary. Therefore, it was not a suitable background well, which is confirmed by later DEC documents identifying the well as a crossgradient well. Background wells AB-12/AB-12D were installed in 2011. Thus, DEC did not have a suitable background well to establish naturally occurring concentrations of compounds until 2011.
- Monitoring wells AB-02S and AB-04S were installed in 2004 near the compliance boundary and property boundary between the ash basins and adjacent residences. Initial sampling of these wells indicated concentrations of iron and manganese above the 2L Standards; there is no indication that further assessment of the extent of impacts was performed or that a receptor survey was performed to identify nearby potential water supply wells in the residential areas. A receptor survey conducted in 2014 after the Dan River release indicated a number of water supply wells in the adjacent residential area were impacted.

- In 2011, at the request of DEQ, additional groundwater monitoring wells were installed along the compliance boundary. Compounds detected above 2L Standards and background levels at the compliance boundary included boron (up to 1,020 µg/L versus the 2L Standard of 700 µg/L), nickel (up to 564 µg/L versus to 2L Standard of 100 µg/L), iron (up to 20,800 µg/L versus the 2L Standard of 300 µg/L and 2017 estimated background value of 884 µg/L), and manganese (up to 11,600 µg/L versus the 2L Standard of 50 µg/L and 2017 estimated background value of 225 µg/L).

Groundwater monitoring at Allen Steam Station began in 2004 in monitoring wells AB-01 through AB-05. Site maps showing the well locations and approximate groundwater flow directions are included as Hart Exhibit 40A, and an Excel spreadsheet of groundwater data for the facility is included as Hart Exhibit 40B.

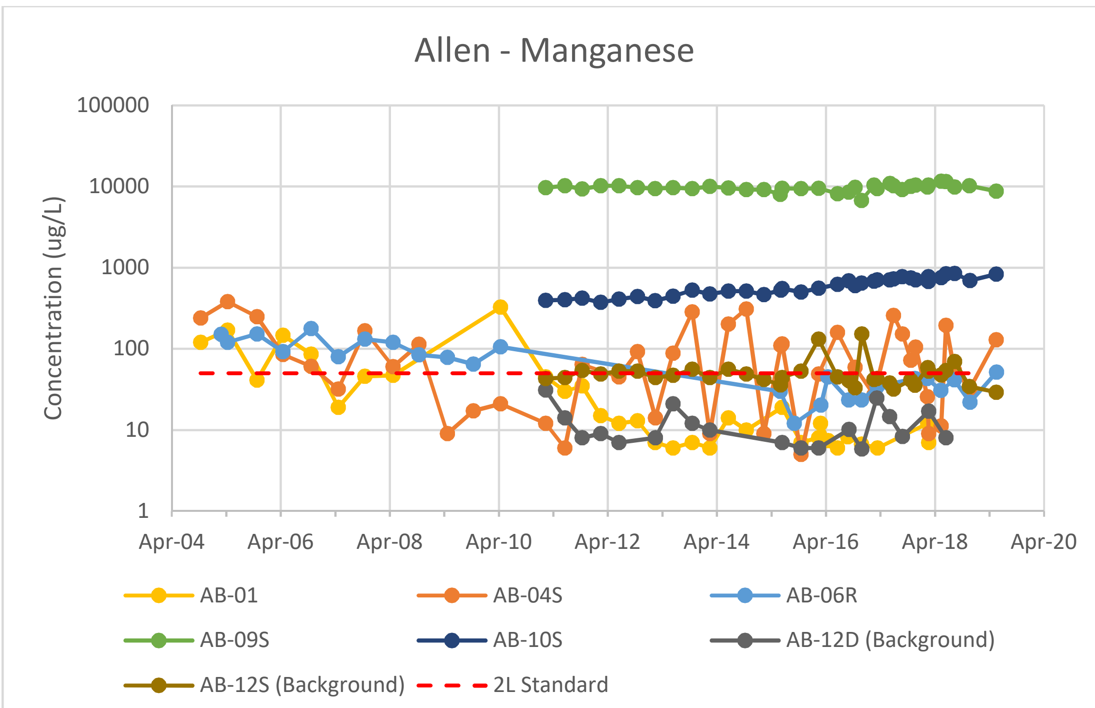
In 2004, iron and manganese were detected at concentrations exceeding the 2L Standards in AB-01, AB-02, AB-04S, AB-04D, and AB-05. Wells AB-02 and AB-04S are located crossgradient of the inactive and active ash basin waste boundaries, respectively, near the compliance boundary (AB-04 was later designated by DEC as a compliance boundary well), AB-01 is located crossgradient to downgradient of the retired ash basin waste boundary and along the ash basin compliance boundary; and AB-05 is located cross-gradient to downgradient of the active ash basin waste boundary. Note that an email summary of DEC's meeting with DEQ prior to installation of the wells at the

Allen facility indicates that DEQ specifically requested two additional monitoring wells between the ash basin and the adjacent housing development (Hart Exhibit 28). It appears that this request was addressed through the installation of wells AB-04/04D or wells AB-02/2D. In either case, the request demonstrates DEQ's concern with potential groundwater migration toward the adjacent residences.

In DEC's 2010 response to DEQ regarding groundwater data, AB-01 was designated as the background groundwater quality monitoring well. However, based on topography and groundwater flow maps issued for the facility, AB-01 is located in a crossgradient to downgradient direction of the western extent of the ash basin. Because of the potential for groundwater impacts from the ash basin, AB-01 is not a suitable well for measuring naturally occurring concentrations in groundwater. This is confirmed in later DEC submittals which indicate that AB-01 is a crossgradient well. DEC knew or should have known that there were significant exceedances of the 2L Standards at the compliance boundary in 2004. For example, iron was detected in AB-01 at a concentration of 1,000 µg/L versus the 2L Standard of 300 µg/L, and manganese was detected at 120 µg/L versus the 2L Standard of 50 µg/L. This is contrary to DEC indications that there were no 2L exceedances at the compliance boundary as part of the voluntary groundwater monitoring initiated in 2004.

In 2005, AB-6R and AB-6A were installed on the downgradient (east) side of the active ash basin waste boundary adjacent to Lake Wylie. In the initial sampling event, iron (3,471 µg/L versus 2L Standard of 200 µg/L) and manganese (150 µg/L versus 2L Standard of 50 µg/L) were detected at concentrations exceeding the 2L Standards from 2005 to 2010 in AB-6R when DEC stopped sampling the well (sampling of the well resumed in 2015). Chromium was detected in both wells AB-6R and AB-6A at concentrations below the 2L Standard at the time (50 µg/L; the 2L Standard changed in 2010 to 10 µg/L) through 2009; however, concentrations of chromium in those wells were above the chromium concentrations detected in other Site wells. When the 2L Standard changed to 10 µg/L in January 2010, concentrations of chromium were above the 2L Standard in both AB-6R and AB-6A. Iron and/or manganese concentrations typically remained above the 2L Standards in AB-01, AB-02, AB-04S and AB-05 from 2004 to 2009/2010 and in AB-04S until 2019.

Except for AB-01 and AB-04/4D, DEC installed the previous wells within the compliance boundary. In 2010, DEQ requested that DEC install additional monitoring wells along the downgradient compliance boundary. Duke installed wells AB-12 and AB-12D as background wells in 2011, and concentrations detected in the background wells have fluctuated above and below the 2L Standards. Additional monitoring wells were installed in 2011, including wells AB-09S and AB-10S in the vicinity of the downgradient compliance boundary. Groundwater flow from the active ash basin is directly toward the AB-09S and AB-10S. In AB-09S, manganese (up to greater than 10,000 µg/L) and iron (up to greater than 20,000 µg/) were detected well above the 2L Standards between 2011 and 2019. Manganese in AB-10S (up to greater than 800 µg/L) was also detected in downgradient above the 2L Standard. Concentrations detected in downgradient well AB-09S and AB-10S were substantially above the concentrations in background wells MW-12S/MW-12D. A graph of manganese concentrations in wells over time in wells (including the background wells MW-12/12D) is provided below. Please note that the vertical axis on the graph below is a logarithmic scale due to the very high concentrations of manganese (approximately 10,000 µg/L versus 2L standard of 50 µg/L) in well AB-09S.



AB-09S indicated 2L Standard exceedances of boron from 2011 to 2019 (up to 1,020 µg/L versus the 2L Standard of 700 µg/L), and boron was not detected in the background monitoring wells. As noted previously, chromium was detected in AB-06A and AB-06R downgradient of the ash basin. Sampling conducted by DEC indicates that the chromium is primarily present in its hexavalent form, which is the more toxic form of chromium.

Vanadium and cobalt were not included in analytical results until 2015. Concentrations of vanadium above the DEQ Interim Maximum Allowable Concentration (IMAC) were detected in wells around the ash basin from the 2015 sampling events to 2019, although concentrations were typically consistent with background levels. An IMAC is an interim standard by DEQ which is interim until a final standard is adopted but, until that time, an IMAC is treated the same as a 2L Standard with regard to determining compliance. Cobalt was detected at concentrations exceeding the IMAC and background in AB-09S, AB-10S, and AB-14D between 2015 and 2018/2019. Nickel was detected in AB-14D at concentrations above the 2L Standard and background from 2011 through 2013, and typically was below the 2L Standard after 2013. Well AB-14D is located along the compliance boundary adjacent to a residential area.

Additional background wells were installed in 2015 including BG-1S, BG-2S/D, BG-4S/D/BR, GWA-19S, GWA-21S/BR, GWA-23S, GWA-26S/D. In 2017, DEC established "background threshold values" or BTVs for site groundwater. BTVs are background values based upon statistical analysis of the data. A comparison of historical downgradient concentrations to the BTVs indicates that concentrations of iron, manganese, chromium, cobalt, and boron were above the BTVs.

VI. BELEWS CREEK STEAM STATION

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The Belews Creek facility has operated one ash basin since the plant began operation in 1974. The ash basin is approximately 340 acres and received a cumulative amount of almost 10 million cubic yards of coal ash. The basin received wet sluiced coal ash and other wastewaters. In 1984, Belews Creek converted to dry fly ash handling but still had the ability to wet sluice fly ash until 2018. The basin stopped receiving CCRs in 2018 when a dry bottom ash system was installed. Wastewater will continue to be discharged to the basin until a new Lined Retention Basin is installed.

In addition to CCRs, the ash basin received other wastewaters including power house and yard sumps, water from chemical holding pond, coal yard sumps, stormwater, treated domestic wastewater, remediated groundwater, stormwater from the coal pile, release of ammonia during quarterly testing, metal cleaning waters, and treated FGD wastewater.

Q. PLEASE DISCUSS WHEN DEC BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

- Voluntary groundwater monitoring within the ash basin compliance boundary occurred in 1989 as part of groundwater monitoring for an adjacent CCR landfill, and 2L Standard exceedances for iron and manganese were detected in a well adjacent to a portion of the ash basin.
- In 2007, DEC began sampling wells installed downgradient of the ash basin waste boundary and within the compliance boundary, and exceedances of 2L Standards for manganese and iron were detected. No background wells were installed by DEC.
- Boron concentrations were initially below the 2L Standard but increased dramatically above the standard beginning in 2009 in MW-101S and MW-101D. An FGD scrubber was installed at Belews Creek in 2008 that discharged wastewater to the ash basin which is a likely potential source of the increased boron concentrations in groundwater.
- Concentrations of manganese were above the 2L Standard and increased with time which was evident by sampling conducted by 2008 to 2009. Iron concentrations as high as 46,600 µg/L (versus the 2L Standard of 300 µg/L) and manganese concentration as high as 5,500 µg/L (versus the 2L Standard of 50 µg/L) had been detected in wells inside the compliance boundary by 2009.
- The significant increases in boron and manganese concentrations should have been a warning to DEC that groundwater conditions were deteriorating in the area of the basin which should have triggered additional evaluation (such as downgradient well installation,

determination of the source of the boron, and surface water sampling of a tributary downgradient of ash basin) and corrective action.

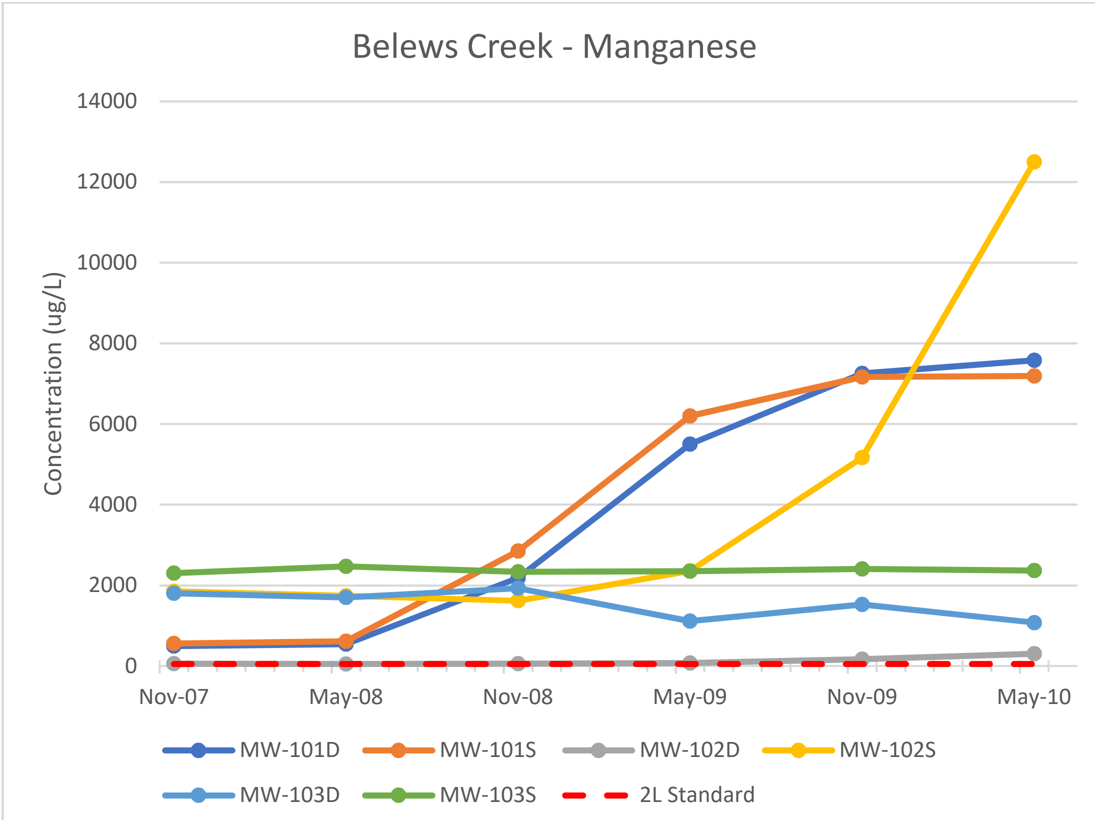
- Sampling along the compliance boundary began in 2011, and background wells MW-202S/D were installed to the south of Pine Hall Road. In comparison to background concentrations and 2L Standards, iron (up to 14,100 µg/L) and manganese (up to 3,600 µg/L) were detected at elevated concentrations in downgradient wells along the compliance boundary.
- In 2015, when the analyte list was expanded, cobalt (up to 19.9 µg/L versus the IMAC of 1 µg/L) and vanadium (up to 8.3 µg/L versus the IMAC of 0.3 µg/L) were detected at concentrations exceeding the IMACs.
- DEC also performed surface water sampling of the tributary downgradient of the ash basin and in the Dan River. High concentrations of boron greater than 9,000 µg/L (versus the North Carolina Instream Target Values for surface water of 150 µg/L for chronic aquatic life protection and 1,500 for acute aquatic life protection) were detected in the tributary and in the Dan River.

Groundwater monitoring at Belews Creek began as early as 1989 in monitoring wells MW-01, MW-02, MW-03, MW-04, and MW-05 along the boundary of the Pine Hall Road Landfill. Site maps showing the well locations and groundwater flow are included as Hart Exhibit 41A and an Excel spreadsheet of groundwater data for the facility is included as Hart Exhibit 41B.

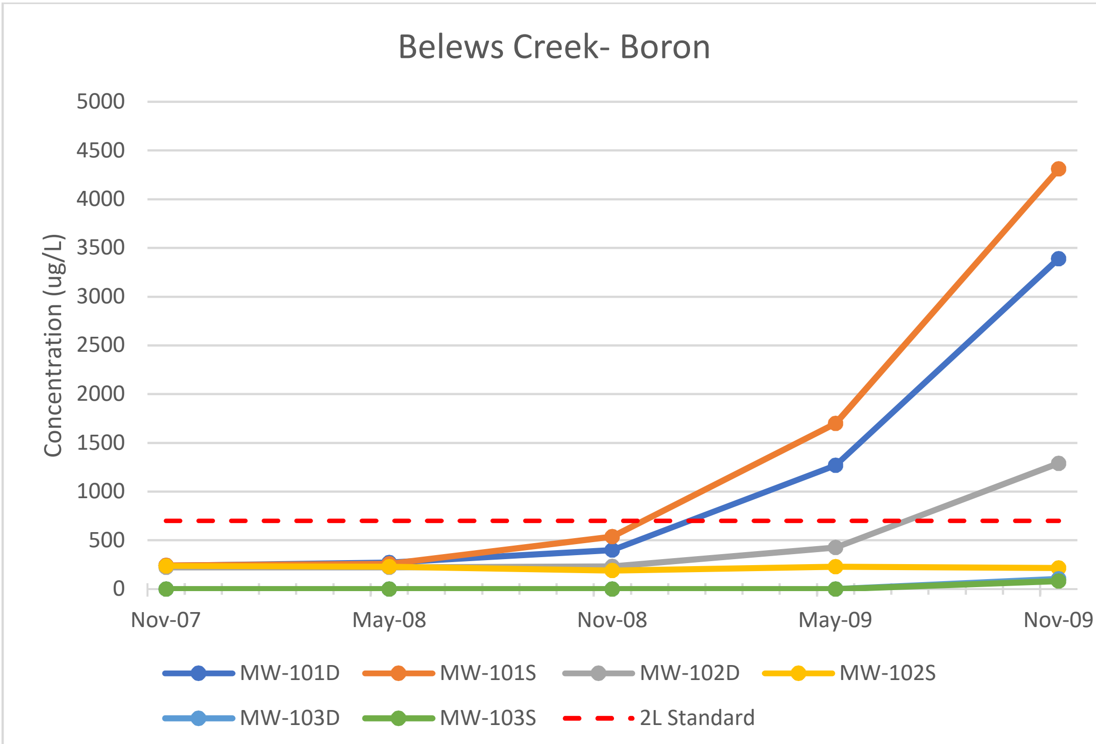
Based on groundwater flow maps, these wells were primarily upgradient of the ash basin waste boundary, but wells MW-03 and MW-04 were within the ash basin compliance boundary and well MW-04 was adjacent to the southwestern tip of the ash basin. Iron and manganese were detected in the early sampling events in 1989 through 1993 in monitoring wells MW-01, MW-02, MW-03, MW-04, and MW-05 at concentrations exceeding the 2L Standards. The detections in following years did not consistently exceed the 2L Standards, except in MW-04. MW-04 is located adjacent to the southwestern tip of the coal ash basin waste boundary and also indicated 2L Standard exceedances of iron at various sampling events from 1989 through 2019. Chromium was also detected in MW-04 from 1989 through 2019 above the concentrations detected in other Site wells and above the 2L Standard established in 2010 10 µg/L, but below the historical 2L Standard of 50 µg/L.

In 2007, monitor wells MW-101S, MW-101D, MW-102S, MW-102D, MW-103S, and MW-103D were installed downgradient of the ash basin near the ash basin waste boundary, but inside the compliance boundary, as part of voluntary monitoring. No wells were installed in an upgradient location. The wells located on the downgradient waste boundary of the ash basin (MW-101 through MW-103) indicated exceedances of 2L Standards when sampled in 2007. Iron and manganese were detected at concentrations exceeding the 2L Standards in MW-101S/D, MW-102S/D, and MW-103S/D. Iron concentrations as high as 46,600 µg/L (versus the 2L Standard of 300 µg/L) and manganese concentration as high as 5,500 µg/L (versus the 2L Standard of 50 µg/L) had been detected in wells inside the compliance boundary by 2009.

As indicated in the graph below, concentrations of manganese increased with time, and this was evident by sampling conducted in 2008 to 2009.



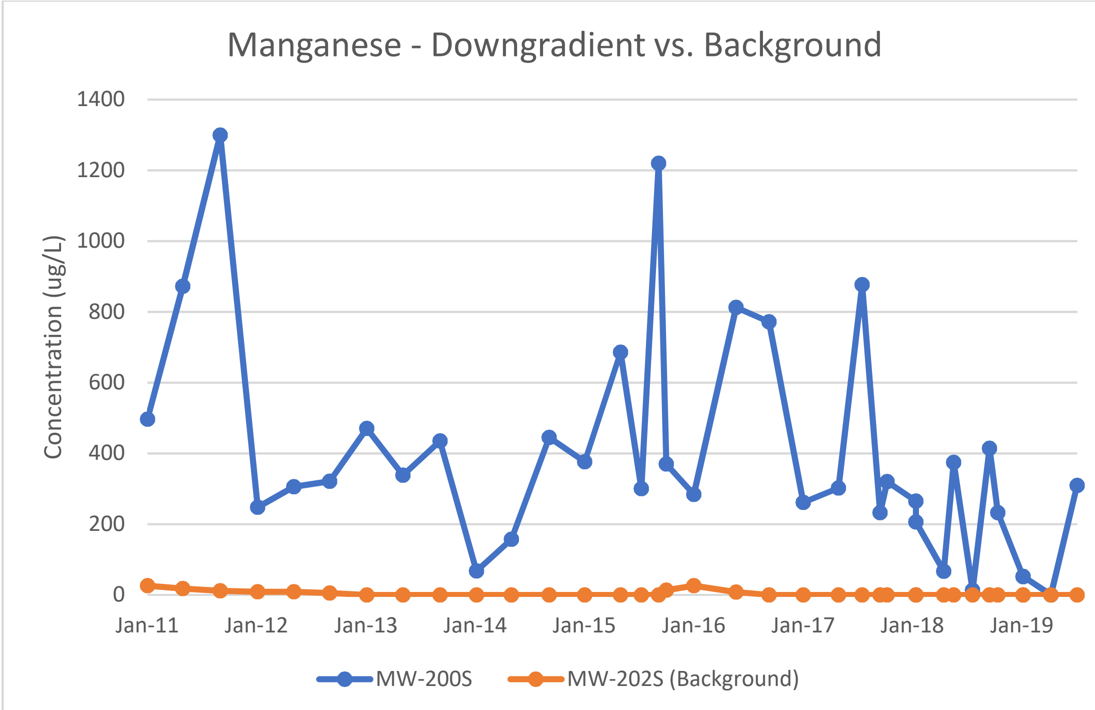
As indicated in the graph below, boron concentrations were initially below the standard but increased dramatically above the standard beginning in 2009 in MW-101S and MW-101D. An FGD scrubber was installed at Belews Creek in 2008 that discharged wastewater to the ash basin which is the most likely potential source of the increased boron concentrations in groundwater. Such significant increases in boron and manganese concentrations should have been a warning to DEC that groundwater conditions were deteriorating in the area of the basin which should have triggered additional evaluation (such as downgradient well installation, determination of the source of the boron, and surface water sampling of a tributary downgradient of ash basin) and corrective action.



For the wells installed within the compliance boundary in 2007, additional compounds were included in the analyte list in 2015 including beryllium, cadmium, cobalt, thallium, and vanadium. Vanadium was detected in MW-104S/D (7.7 µg/L versus the IMAC of 1 µg/L), cobalt was detected in MW-103S/D (79.7 µg/L versus IMAC of 1 µg/L), and beryllium (4.4 µg/L versus the 2L Standard of 4 µg/L was detected in MW-103D at concentrations exceeding the IMAC.

Although groundwater data from wells within the compliance boundary showed 2L Standard exceedances and increasing concentration trends (as shown in the graphs above), DEC did not voluntarily complete any further sampling or delineation. In 2011, following DEQ requests for wells along the compliance boundary, Duke installed wells MW-200S/D through MW-204S/D. Monitoring wells MW-202S/D were installed to determine background concentrations. In the background monitoring wells, manganese was not detected at concentrations exceeding the 2L Standard and, with the exception of isolated events, iron was not detected above the 2L Standard, confirming that detections of iron and manganese in the downgradient wells were not from background conditions.

MW-200S and MW-200D were installed on the northern edge of the compliance boundary, downgradient of the ash basin, and MW-200S indicated 2L Standard exceedances from 2011 to 2019. Similar to other wells, iron (up to 4,300 µg/L) and manganese (up to 1,300 µg/L) were detected at concentrations exceeding the 2L Standards during this timeframe. A comparison of manganese in background well MW-202S to compliance boundary well MW-200S is provided below and clearly indicates that manganese concentrations are above background.



In 2015, when the analyte list was expanded, cobalt and vanadium were detected at concentrations exceeding the IMAC in downgradient well MW-200S. MW-204S/D were installed along the compliance boundary west of the basin and analytical results indicated elevated iron (up to 14,100 µg/L) and manganese (up to 3,600 µg/L) concentrations exceeding 2L Standards from the 2011 sampling event until the most recent 2019 sampling event. Cobalt (up to 19.9 µg/L) exceeded the IMAC of 1 µg/L from 2015 through 2019.

PBTVs were established in 2017 for the facility. The PBTV for iron in shallow groundwater is 750 µg/L, and the PBTV for manganese in shallow groundwater is 22.9 µg/L (which is less than the 2L Standard of 50 µg/L). A review of historical data indicates that concentrations of multiple metals exceed the PBTVs.

DEC also performed surface water sampling of the tributary downgradient of the ash basin and in the Dan River. High concentrations of boron greater than 9,000 µg/L (versus the North Carolina Instream Target Values for surface water of 150 µg/L for chronic aquatic life protection and 1,500 for acute aquatic life protection) were detected in the tributary and in the Dan River.

VII. BUCK STEAM STATION

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The Buck facility has three basins that total approximately 130 acres. The initial ash basin began operation in 1957 and was modified over time to increase capacity. In 1977, the eastern portion of the main dam was increased in height by 10 feet and a divider dam was added to divide the basin into a Primary Pond (Basin 2) and a Secondary Pond (Basin 3). In 1982, construction began on the Additional Primary Basin (Basin 1) located upgradient of Basins 2 and 3 to provide additional capacity for sluiced CCRs. During operation, the ash ponds received sluiced CCRs and other wastewater streams. The power plant was never converted to dry ash handling. All coal units at the plant were retired by 2013.

A cumulative amount of approximately 5.3 million cubic yards of CCRs were placed in the basins. In addition to CCRs, wastewater streams discharged to the basins included coal pile runoff, water treatment wastes, wet scrubber air pollution control waters, laboratory and sampling streams, boiler/condenser/cooling tower blowdowns, metal cleaning wastes, domestic wastewater, petroleum-contaminated groundwater, and stormwater runoff. In 2011, the basins were permitted to receive wastewaters from the Combustion Turbine Combined Cycle (CTCC) plant at the facility which started up in 2011.

Q. PLEASE DISCUSS WHEN DEC BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

- Voluntary groundwater monitoring was completed by DEC as early as 2006 at wells within the compliance boundary. Monitoring wells MW-6S/D were installed upgradient of the ash basin along the Site boundary and were designated background wells. Iron (up to 4,682 µg/L versus 2L Standard of 300 µg/L), manganese (up to 2,672 µg/L versus 2L Standard of 50 µg/L), and boron (up to 1,309 µg/L versus the 2L Standard of 700 µg/L) were detected at concentrations exceeding the background concentrations and the 2L Standards in wells on the downgradient waste boundary in sampling conducted in 2006.
- DEC did not complete additional sampling along the compliance boundary to evaluate if impacts were present at the compliance boundary until DEQ required additional wells be installed.

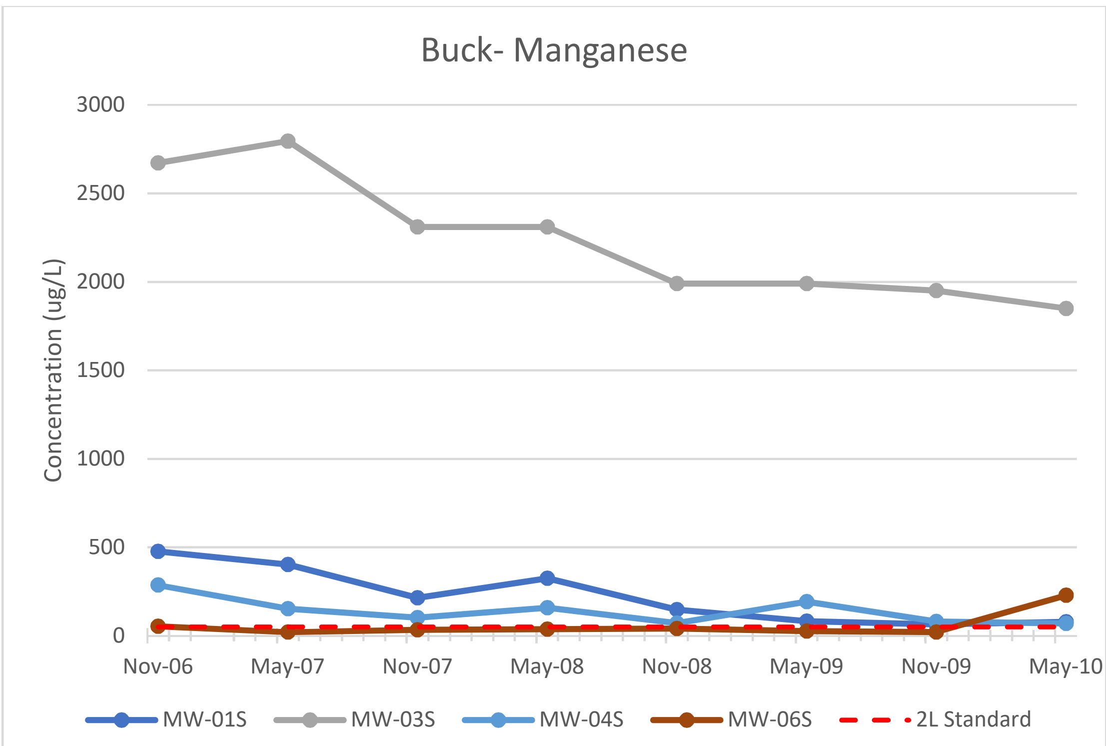
- Groundwater monitoring along the compliance boundary began in 2011. Sulfate (up to 410 mg/L versus the 2L Standard of 250 mg/L), total dissolved solids (up to 700 mg/L versus the 2L Standard of 500 mg/L), boron (up to 1,320 µg/L), iron (up to 7,340 µg/L), and manganese (up to 1,130 µg/L) were detected in the downgradient compliance boundary wells at concentrations exceeding the 2L Standards and Site-specific background concentrations.
- PBTVs established in 2017 for iron was up to 646.9 µg/L and for manganese was up to 197.9 µg/L. The PBTVs for boron, sulfate, and TDS were all less than 2L Standards.

Groundwater monitoring at the Buck facility began in 2006 with monitoring wells MW-01D/S through MW-06S/D. Site maps showing the well locations and groundwater flow are included as Hart Exhibit 42A and as Excel spreadsheet of groundwater data (and other sampled media data) is included as Hart Exhibit 42B.

MW-01S is located to the northwest and downgradient of Basin 1, and MW-03S/D and MW-04S/D are located to the north and downgradient of Basins 2 and 3. All the wells were located within the compliance boundary. In MW-01S, iron was initially detected at 4,682 µg/L versus the 2L Standard of 300 µg/L, and manganese was detected at 476 µg/L versus the 2L Standard of 50 µg/L. In MW-04S iron was detected initially at 404 µg/L but increased to 9,210 µg/L by 2009, and manganese concentrations were initially 286 µg/L but generally decreased although remained above the 2L Standard through 2010.

MW-03S, downgradient of the ash basin to the north, indicated boron (up to 1,309 µg/L), iron (up to 6,900 µg/L), and manganese (up to 2,796 µg/L) concentrations above the 2L Standards from 2006 through 2019.

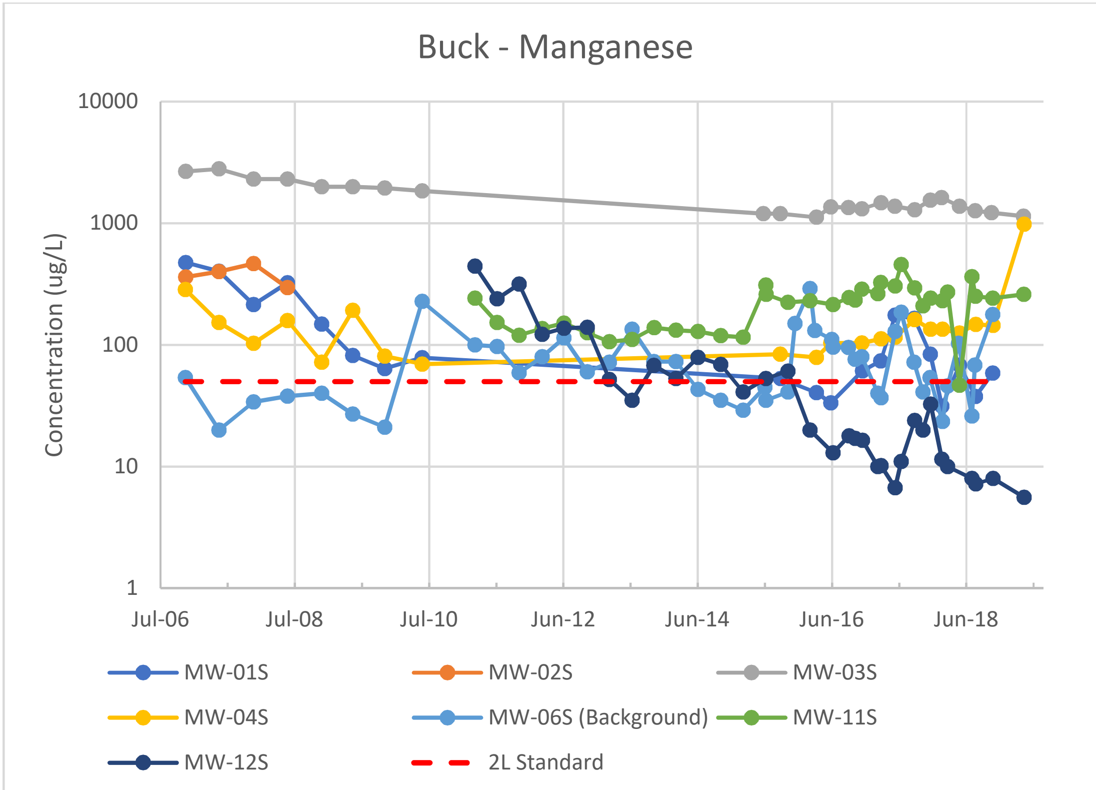
Upgradient wells MW-06S and MW-06D were identified as background wells, and these wells are reasonably located in background locations. Historical sampling events indicate that although MW-6S had 2L exceedances of iron and manganese, the concentrations of iron and manganese were generally higher in the downgradient wells as compared to the upgradient wells. A plot of manganese concentrations from 2006 to 2010 in these wells is shown below in comparison to background well MW-06S.



Downgradient well MW-03S indicated 2L exceedances of boron, and boron was not detected in the background wells MW-06S/D.

Analytical data from the wells installed along the ash waste boundary, but within the compliance boundary, showed 2L Standard exceedances as well as concentrations above background concentrations. DEC did not complete additional sampling along the compliance boundary to evaluate if impacts were present at the compliance boundary until DEQ required additional wells to be installed.

As required by DEQ, monitoring wells MW-07S/D through MW-13D were installed along the compliance boundary and first sampled in 2011. The wells located directly downgradient of the ash basins include MW-9S/D, MW-10D, and MW-11S/D. From 2011 to 2018, sulfate (up to 410 mg/L) and TDS (up to 700 mg/L) were above the 2L Standard in MW-10D, boron (up to 1,320 µg/L) and iron (up to 3,810 µg/L) were detected above the 2L Standard in MW-11D, and manganese (up to 458 µg/L) was detected above the 2L Standard in MW-11S. Manganese concentrations from 2006 to 2019 for downgradient wells compared to the background well are shown on the graph below. Please note the Y-axis is set as a logarithmic scale because of the high concentrations detected in well MW-03S.



PBTVs were established in 2017 for the facility. PBTVs established in 2017 for iron was up to 646.9 µg/L and for manganese was up to 197.9 µg/L. The PBTVs for boron, sulfate, and TDS were all less than 2L Standards. A review of historical data indicates that concentrations of multiple metals exceed the PBTVs.

VIII. CLIFFSIDE STEAM STATION

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The Cliffside facility operated three coal ash basins over time for the disposal of sluiced CCRs and other wastewaters. The initial ash basin, referred to as the Units 1-4 Inactive Basin, was approximately 14 acres and operated from 1957 to 1977 when it reached capacity. This basin was excavated in 2016 for construction of a stormwater pond. It is unclear if any type of "closure" was performed on the basin between 1977 when it reached capacity and 2016 when the pond was excavated. A second basin was constructed in 1970 in advance of operation of Unit 5 and is referred to as the Unit 5 Inactive Basin. This basin was approximately 46 acres and operated until 1980 when it reached capacity. It is unclear what, if any, type of closure was performed on the basin when it reached capacity.

A third basin was constructed in 1975 and was expanded in 1980. This basin is approximately 84 acres and also received CCRs from Unit 5. The facility converted to dry ash handling in 2018 and CCRs are no longer placed in the ash basin. Approximately 6.5 million cumulative cubic yards of ash were placed in the three ponds over time.

In addition to CCRs, other wastewater streams placed in the basins include coal pile runoff, metal cleaning wastes, treated domestic wastewater, water treatment system wastewaters, landfill leachate, runoff from stacking areas, cooling tower blowdown, and FGD wastewater.

Q: PLEASE DISCUSS WHEN DEC BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

- Voluntary groundwater monitoring was performed in 2008 at wells located along the ash basin waste boundary. Concentrations in downgradient wells indicated 2L Standard exceedances of manganese (up to 33,300 µg/L versus 2L Standard of 50 µg/L) and iron (up to 3,730 µg/L versus the 2L Standard of 300 µg/L). Background concentrations were not established until 2011 at the facility.
- Although concentrations within the compliance boundary indicated 2L Standard exceedances, no additional sampling or installation of wells along the compliance boundary was completed by DEC until required to do so by DEQ.
- In 2011, monitoring wells MW20D/DR through MW-25DR wells installed along the compliance boundary, including background wells MW-24D/S. Iron (up to 9,890 µg/L) and manganese (up to 683 µg/L) were detected along the downgradient compliance boundary above 2L Standards and the background values in multiple monitoring wells. Additionally, TDS (up to 430 mg/L versus 2L Standard of 250 mg/L), and sulfate (up to 820 mg/l versus 2L Standard of 500 mg/L) exceeded 2L Standards and background levels in downgradient compliance well MW-23D.
- Monitoring wells MW-02DA, MW-20DR, MW-22DR, MW-23DR were installed in bedrock and indicate 2L exceedances of iron and/or manganese. In accordance with the 2L Rules, the compliance boundary

does not apply to bedrock contamination and contamination within the bedrock must be remediated.

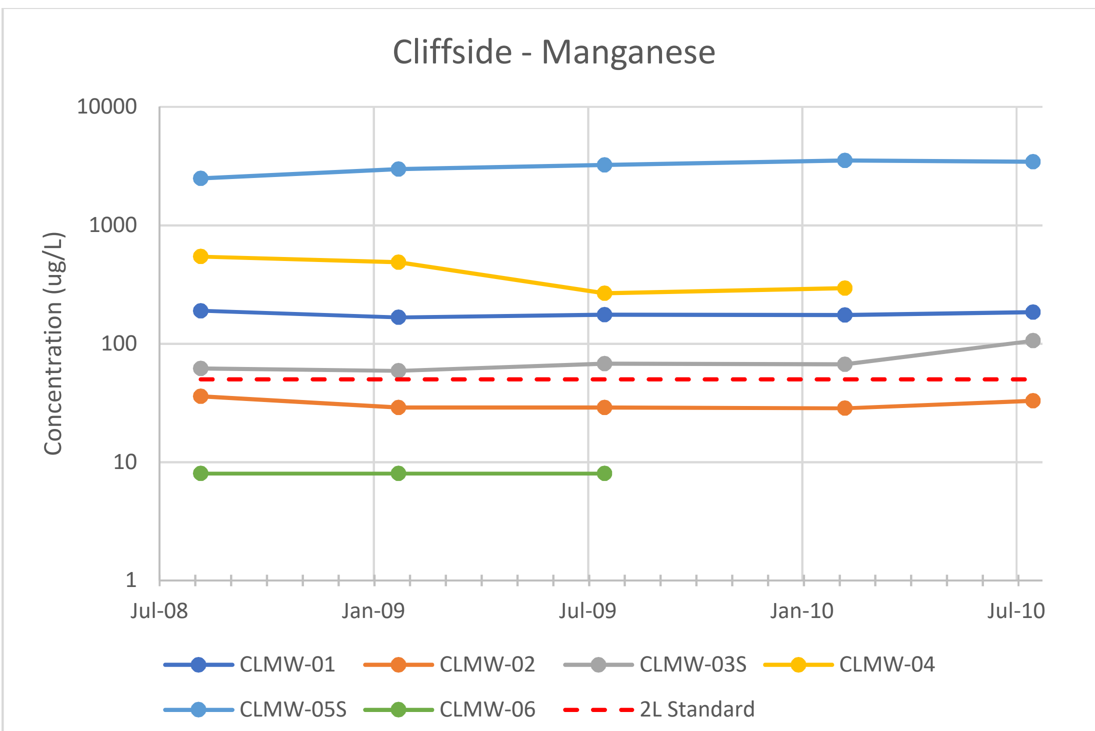
- Since at least 2015, boron concentrations have been increasing with time in multiple wells inside the compliance boundary, potentially because of the addition of FGD wastewaters.

Groundwater monitoring began at the Cliffside facility in 2008 in monitoring wells CLMW-01 through CLMW-06, MW-02D, MW-04D, MW-08S/D, MW-10S/D, and MW-11S/D. With the exception of CLMW-06, all wells monitored between 2008 and 2010 were on the downgradient side of the active ash basin and inside of the compliance boundary. Site maps showing the well locations and groundwater flow are included as Hart Exhibit 43A and an Excel spreadsheet of groundwater data for the Site is included as Hart Exhibit 43B. CLMW-06 was located along the southern boundary of the active ash basin, within the compliance boundary and crossgradient of the basin.

Manganese (up to 230 µg/L) was detected in CLMW-01 exceeding the 2L Standard in each sampling event in which it was analyzed between 2008 and 2019, and boron (up to 1,850 µg/L versus 2L Standard of 700 µg/L), cobalt (up to 2.8 µg/L versus IMAC of 1 µg/L), and thallium (up to 0.63 µg/L versus the IMAC of 0.2 µg/L) were detected above the 2L Standard or IMAC from 2015 to 2019. Manganese was also detected above the 2L Standard in CLMW-03S (initially at 62 µg/L in 2008 but increasing to 4,830 µg/L by 2019) and CLMW-05S (initially 2,490 µg/L in 2008 and increasing to 5470 µg/L in 2019). CLMW-4 indicated iron (up to 62,200 µg/L) and manganese (up to 545 µg/L)

2L Standard exceedances during the six sampling events in which it was sampled between 2008 and 2015. MW-04D, MW-08D, and MW-08S indicated significant iron and manganese 2L exceedances (up to 37,500 µg/L manganese and 5,620 µg/L) for the sampling events between 2008 and 2019.

Concentrations of manganese in shallow wells located within the compliance boundary between 2008 and 2011 are shown on the graph below. Please note, the Y-axis is shown on a logarithmic scale due to the high concentrations in well CLMW-05S (greater than 5,000 µg/L). As indicated in the graph, concentrations of manganese were above the 2L standard in CLMW-01, CLMW-03S, CLMW-04S, and CLMW-05S.



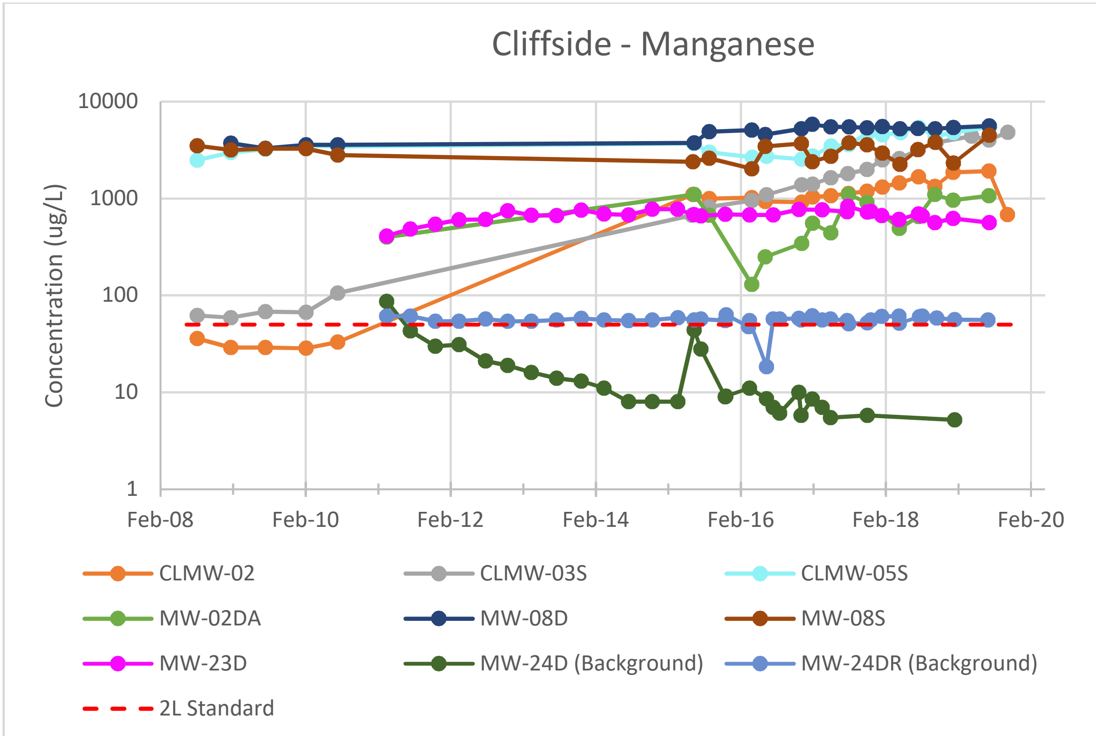
Concentrations of chromium (up to 70.7 µg/L) were detected in deeper well MW-2D above the historical 2L Standard of 50 µg/L from 2009 to 2010.

In correspondence with DEQ dated April 2009, Duke identified MW-2D and CLMW-02 as background monitoring wells to assess naturally occurring conditions at the Site. However, DEQ indicated that it did not consider these wells background. Background wells for the Site were not established until wells MW-24D and MW-24DR were installed and first sampled in 2011.

Although concentrations within the compliance boundary indicated 2L Standard exceedances (as shown in the graph above), no additional sampling or installation of wells along the compliance boundary was completed by DEC. Only after DEQ required wells be installed along the compliance boundary, did DEC install additional monitoring wells. Monitoring wells MW20D/DR through MW-25DR were installed along the compliance boundary and sampled from 2011 through 2019. MW-24D and MW-24DR were installed on the southern end of the Site, outside of the compliance boundary to establish background concentrations for the Site. With the exception of inconsistent 2L Standard exceedances of iron and concentrations of vanadium exceeding the IMAC in some sampling events (maximum of 2.77 µg/L), concentrations detected in MW-24D were typically below the 2L Standards or IMAC between 2011 and 2019. MW-24DR indicated 2L exceedances of iron and manganese from 2011 to 2019. In MW-24DR, iron concentrations ranged from 395 to 2,320 µg/L, and manganese concentrations ranged from 18.4 to 61.4 µg/L.No other compounds were detected above the applicable 2L Standards or IMAC in the MW-24DR background well.

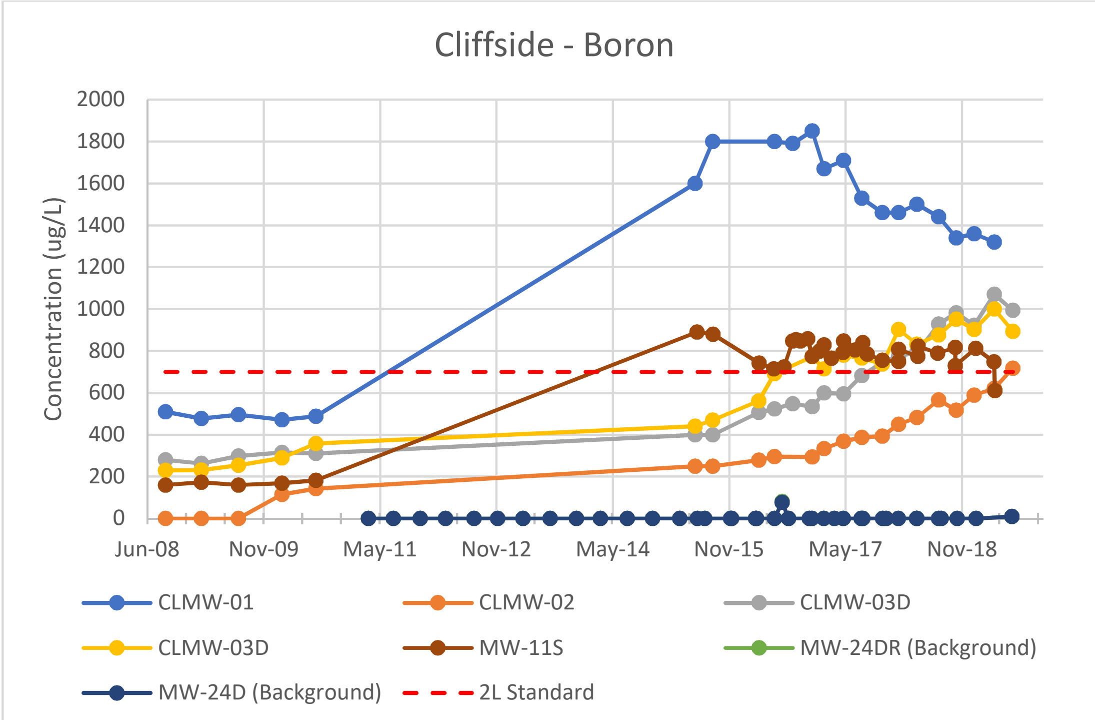
Compliance boundary wells MW-20D and MW-20DR, located downgradient of the ash basin, indicated concentrations of manganese up to 704 µg/L from 2011 through 2019 above the 2L Standard, and significantly greater than background concentrations. Iron was also detected in MW-20D at concentrations exceeding the 2L Standard and background levels, with a maximum concentration of 10,600 µg/L. MW-22DR, installed to the east and downgradient to crossgradient of the ash basin, indicated similarly elevated concentrations of iron as MW-20D (up to 9,890 µg/L), well above the 2L Standard and background concentrations. MW-23D/DR were installed on the western compliance boundary, crossgradient of the ash basin, and indicated elevated levels of iron (up to 1,370 µg/L) compared to background concentrations. Additionally, manganese (up to 831 µg/L), sulfate (up to 420 µg/L), and TDS (up to 820 µg/L) were detected above the 2L Standards and background concentrations.

A graph of manganese concentrations with time as compared to background and the 2L Standards is provided below. Note that vertical axis is on a logarithmic scale.



In addition to the 2L exceedances detected in wells installed prior to 2011, additional compounds were detected above 2L Standards when the well samples were analyzed for additional compounds in 2015. Concentrations in wells CLMW-01, CLMW-02, CLMW-03S, CLMW-05S, CLMW-06, MW-08D, MW-08D, MW-10D/S, MW-11S, and MW-22DR indicated IMAC exceedances for cobalt between 2015 and 2019. Boron concentrations in MW-11S increased to concentrations exceeding the 2L Standard in 2015.Sulfate and total dissolved solids in MW-23D exceeded the 2L Standards from 2011 through 2019 in MW-23D.

A graph of boron concentrations with time is provided below and indicates boron concentrations have been increasing with time in multiple wells, potentially because of the addition of FGD wastewaters as noted by DEC. A wet scrubber was installed at the Cliffside facility in October 2010.



Monitoring wells MW-02DA, MW-20DR, MW-22DR, MW-23DR were installed in bedrock and indicate exceedances of iron and manganese. In accordance with the 2L Rules, the compliance boundary does not apply to bedrock contamination and contamination within the bedrock must be remediated.

In 2015, Duke installed additional groundwater monitoring wells BG-1S/D/BR, BG-2D, MW-30S/D, and MW-32S/D/BR. The newly installed wells along with the MW-24D/DR and CCMPW-1S and CCPMW-1D wells were used in 2017 to statistically determine BTVs for the site. Historical data were above the BTVs for multiple metals.

IX. DAN RIVER STEAM STATION

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. At the Dan River facility, two ash basins were used to dispose of CCRs. A single ash basin was constructed in 1956 and that area was expanded in 1968. In the mid-1970s, DEC modified the expanded basin to increase storage capacity and two basins referred to as the Primary and Secondary Basins were formed. The two basins are approximately 33 acres and during operation received a cumulative total of approximately 1.5 million cubic yards of CCRs. The facility was never converted to dry ash handling and the use of coal at the facility ceased in 2012.

In addition to CCRs, wastewaters that were managed in the basins included stormwater, fuel oil storage runoff, floor drains, make up water process wastes, boiler cleaning wastewater, treated sanitary wastes, lab wastes, and flocculation chemicals such as ferric sulfate.

In February 2014, DEC released between approximately 30,000 and 39,000 tons of CCRs from the Primary Basin as a result of failure of an underlying stormwater pipe. DEC pleaded guilty to criminal negligence in Federal Court for violating the Clean Water Act due to its negligent operation of the Dan River facility which led to this release. Subsequently, DEQ requested that DEC submit a closure plan for excavation of the ash by November 2014. Excavation of ash from the basins began in 2015 and was completed in 2019.

Q: PLEASE DISCUSS WHEN DEC BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE

RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

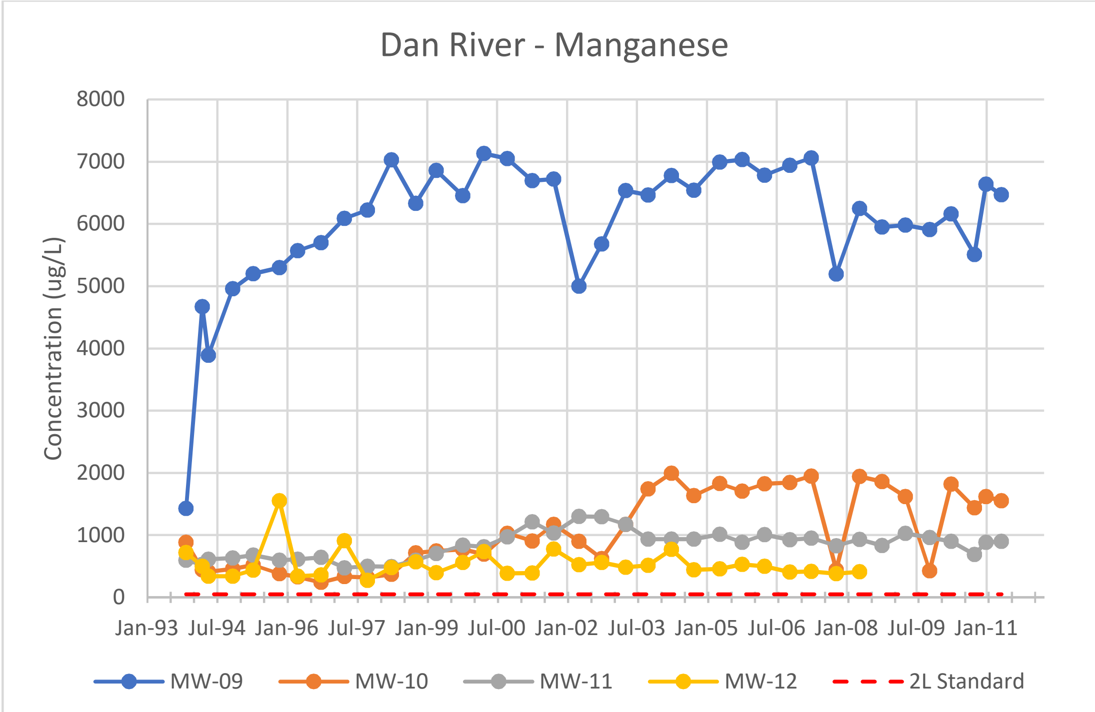
A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

- Groundwater sampling was initially completed at Dan River in 1993. Concentrations from wells located within the compliance boundary indicated concentrations of iron (up to 5,678 µg/L versus the 2L Standard of 300 µg/L), sulfate (up to 582 mg/L versus 2L Standard of 250 mg/L), and manganese (up to 2,133 µg/L) exceeding the 2L Standard. DEC did not install a background well until 2011.
- Although 2L Standard exceedances were detected at the Site as early as 1993, DEC never completed additional monitoring to determine compliance at the compliance boundary or the extents of groundwater impacts until requested to do so by DEQ in 2011.
- In 2011/2012, groundwater monitoring along the compliance boundary was completed and concentrations of iron (up to 2,890 µg/L), manganese (up to 934 µg/L), arsenic (up to 32.2 µg/L versus the 2L Standard of 10 µg/L), boron (up to 743 µg/L versus the 2L Standard of 700 µg/L), sulfate (up to 310 mg/L) and TDS (up to 643 µg/L) were detected above the 2L Standards and background at that time.
- After being added to the analyst list in 2015, cobalt (up to 7.8 µg/L versus the 1MAC of 1 µg/L) and vanadium (up to 2.42 µg/L versus the

IMAC of 1 µg/L) were also detected above IMACs and background levels.

DEC began monitoring groundwater at the Dan River facility as early as 1993 as part of an NPDES permit requirement. Site maps showing the well locations and groundwater flow are included as Hart Exhibit 44A and an Excel spreadsheet of groundwater data for the Site is included as Hart Exhibit 44B.

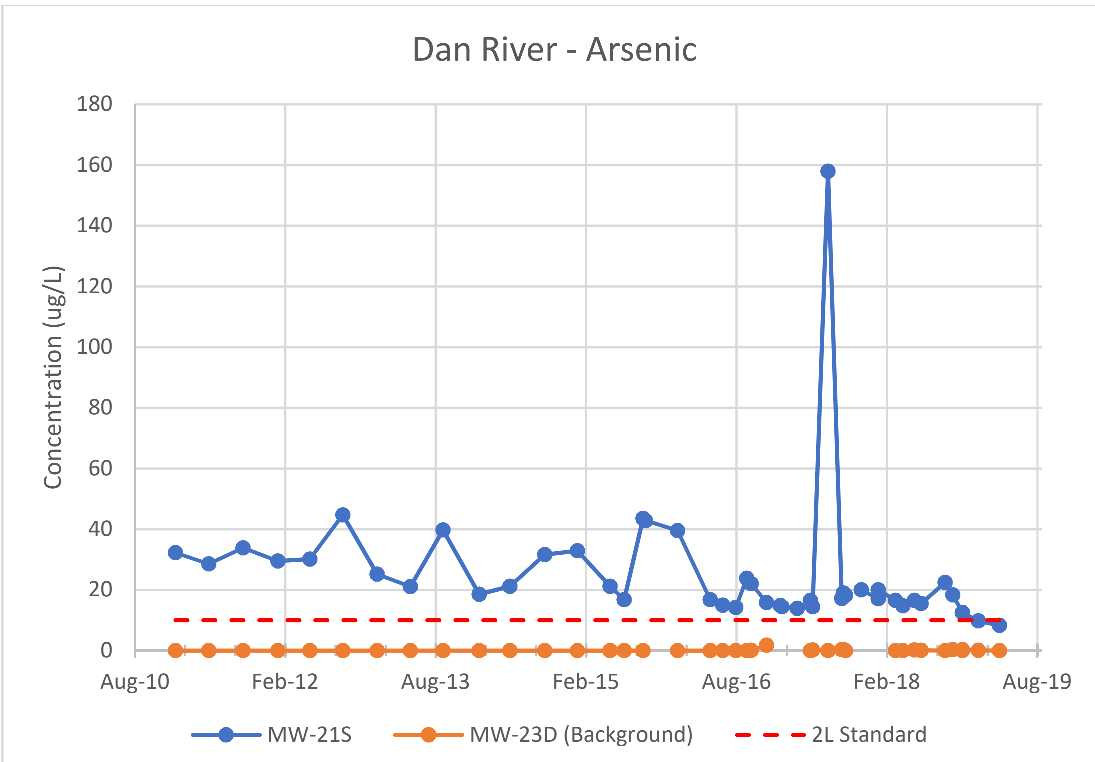
MW-08 was sampled from 1993 to 1996 for a select list of metals including sulfate, iron, and manganese which were all detected above the 2L Standards during that time period. MW-08 was located to the north of the Secondary Ash Basin, cross to downgradient of the ash basin, and was abandoned sometime after 1996. In MW-08, iron was detected up to 5,678 µg/L, sulfate up to 582 mg/L, and manganese up to 2,133 µg/L). MW-09 and MW-10 were sampled from 1993 to 2015 and manganese in both wells (up to 10,000 µg/L) and iron in MW-09 (up to 7,132 µg/L) were detected above the 2L Standards for the sampling period. MW-09 is located to the south of the Primary Ash Basin, and MW-10 is located to the west of the Primary Ash Basin. Both wells are located downgradient and within the ash basin waste boundary. MW-11 is located downgradient of the Secondary Basin, within the waste boundary, and indicated concentrations of manganese (up to 1,300 µg/L) exceeding the 2L Standard from 1993 to 2016 and iron above 2L Standard (up to 15,070 µg/L) from 1993 to 2004. A graph showing manganese concentrations detected at the facility between 1993 and 2011 is shown below. Concentrations in MW-09 were substantially greater than the 2L Standard.



In 2009, DEC identified MW-12 and MW-12D as background wells. However, the wells are located to the northwest and downgradient of the Primary Basin and therefore are not suitable for background evaluation.

Although 2L Standard exceedances were detected at the Site as early as 1993, DEC never completed additional monitoring to determine the extent of groundwater impacts. In 2009, DEQ required that DEC install wells along the compliance boundary. In 2010, background well MW-23D was installed on the western side of the Site. Iron was detected in MW-23D at concentrations above 2L Standards from 2011 through 2017, with a maximum concentration of 2,890 µg/L, and manganese was detected above 2L Standards between 2011 and 2019 in MW-23D, with a maximum concentration of 566 µg/L. Iron and manganese in multiple downgradient wells were detected above background. Iron in compliance boundary well MW-22S reached a maximum concentration of 19,400 µg/L, well above the maximum background concentration.

A graph comparing arsenic concentrations at the downgradient well MW-21S to the background concentrations detected at MW-23D from 2011 through 2018 is shown below and indicates that arsenic has been detected in the well above background and the 2L standard.



Sulfate was detected above the 2L Standard in the few sampling events completed at MW-8 and was also detected above the 2L Standard in MW-21D from 2011 through 2016 and again in 2019. TDS in MW-21D also exceeded the 2L Standard during that time period. Boron was detected at consistently elevated concentrations in MW-9D (up to 1,110 µg/L), downgradient of the Primary Basin, from 2008 through 2018. Similar to other facilities, cobalt was not added to the analyte list until 2015 at which time it was detected above the IMAC in MW-12, MW-12D, MW-20S, and MW-21S. Vanadium was also detected above the 2L Standard in well MW-21S. Compliance boundary monitoring well MW-21S, located downgradient of the Secondary Basin along the stream on the northeastern part of the Site, indicated arsenic concentrations (up to 44.7 µg/L) from 2011 to 2019 exceeding the 2L Standard. Arsenic, boron, cobalt, and sulfate were not detected above the 2L or IMAC in any sample collected from the background monitoring well.

In 2015, additional background monitoring wells BG-5S/D, BG-10S/10D, and GWA -9S/D were installed at the facility in addition to the MW-23D/BR wells previously installed. In 2017, the wells were used to determine the PBTVs. In shallow wells, concentrations of historical downgradient samples exceed the BTVs.

X. MARSHALL STEAM STATION

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The Marshall facility began operation in 1965 and has one coal ash basin referred to as the Ash Basin that is approximately 450 acres in area. The Ash Basin received sluiced fly ash and bottom ash from 1965 to 1984 when the facility converted to dry fly ash handling. Dry fly ash was subsequently placed in an on-site landfill. Bottom ash continued to be placed in the Ash Basin until 2018 when the facility converted to dry bottom ash handling. A cumulative 14 million cubic yards of CCRs were placed in the Ash Basin over time.

In addition to CCRs, the Ash Basin received other waste streams including metal cleaning wastewater, coal pile runoff, stormwater, low volume wastes, landfill leachate, treated domestic wastewater, boiler blowdown, oily wastewater, water treatment process water, and FGD wet scrubber wastewater (added to permit in 2004). The April 2018 NPDES permit indicates that the non-coal ash wastewaters will continue to be discharged to the Ash Basin until construction of a new retention basin.

Q. PLEASE DISCUSS WHEN DEC BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

- Groundwater monitoring began at Marshall in 1989 and included monitoring wells for the on-Site landfills that are also located in the ash basin boundary. No significant concentrations above background were detected in these wells until a broader list of analytes were included. In 2006, concentrations of boron (up to 1,206 µg/L versus the 2L Standard of 700 µg/L) and selenium (up to 44.05 µg/L versus the 2L Standard of 20 µg/L) were detected above 2L Standards in two of these wells.
- In 2007, additional wells (MW-06S/D through MW-09S/D) within the compliance boundary were included in sampling events and indicated

concentrations of boron, cobalt, TDS, iron, and manganese above the 2L Standards, IMAC, and background.

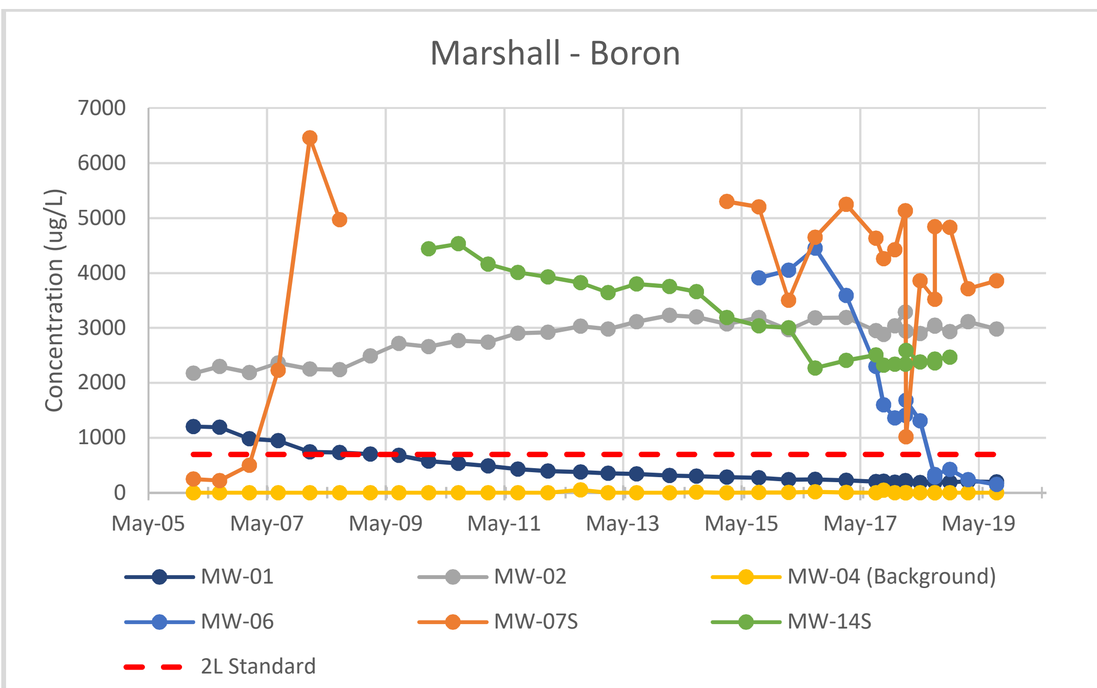
- There was a significant increase in boron concentrations in MW-07S, which is located along the downgradient ash basin boundary during the 2007 to 2010 timeframe (increase from 249 µg/Lin 2006 to 6,460 µg/L in 2009). Three wet scrubbers were added at the Marshall facility in October 2006 through May 2007 which corresponds with the increase in boron concentrations. Such a sharp increase in concentration should have been a warning to DEC of groundwater deterioration during this timeframe which should have resulted in evaluation of the source and extent of the impacts.
- Although concentrations within the compliance boundary indicated significant 2L Standard exceedances and increasing concentrations of boron, no additional sampling or installation of wells along the compliance boundary was completed by DEC until requested to do so by DEQ.
- In 2011, additional wells were sampled over time along the compliance boundary and iron (up to 2,740 µg/L), manganese (up to 130 µg/L), boron ((up to 4,530 µg/L), sulfate (up to 310 mg/L), TDS (up to 540 mg/L), and cobalt (up to 11.1 µg/L) were detected above 2L Standards, IMAC, and background concentrations.

Groundwater monitoring began at the Marshall facility in 1989 with monitoring wells MW-01 through MW-04. Site maps showing the well locations and groundwater flow are included as Hart Exhibit 45A and an Excel spreadsheet of groundwater data for the Site is included as Hart Exhibit 45B.

Monitoring well MW-01 is located in the southeastern landfill boundary and downgradient of the ash basin waste boundary, MW-02 and MW-03 are located around the northern landfill boundary located within the ash basin waste boundary, and MW-04 was located upgradient of the ash basin on the northern compliance boundary. MW-04 was designated the background monitoring well in 2010. The well is located downgradient of the northernmost landfill boundary; however, groundwater concentrations do not appear to have elevated concentrations. With the exception of limited sampling events indicating concentrations of iron and manganese above 2L Standards, MW-04 and MW-04D did not indicate elevated concentrations of iron and manganese in background groundwater. In the 2010 response from DEC to DEQ, DEC identified monitoring wells MW-04 and MW-04D as the background wells for the Site.

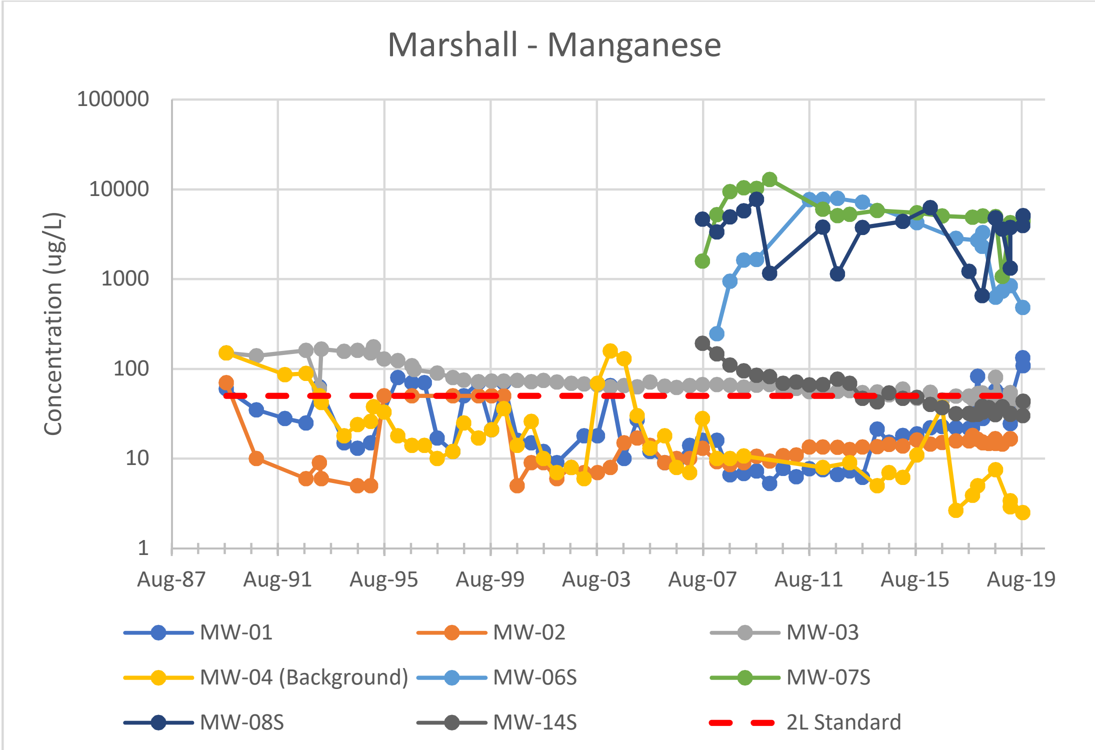
Iron was detected in MW-01 above 2L Standards but generally consistent with background values in various sampling events between 1989 and 2019. From 1989 to 1999, chromium concentrations in MW-01 were above the current 2L Standard of 10 µg/L, but below the historical standard of 50 µg/L. However, compared to background concentrations and other concentrations detected at the Site during that time period, the concentrations were elevated and showed an increasing trend. Boron concentrations in 2006, the first year in which the compound was included as an analyte, were detected above the 2L Standards in MW-01 from 2006 to 2009, and in MW-02 from 2006 to 2019. Selenium was also detected above the 2L Standard and background in well MW-02 when sampled in 2006.

Boron concentrations are shown on the graph below. Based on concentrations detected in background wells, the downgradient 2L Standard exceedances cannot be attributed to naturally occurring concentrations. Note the significant increase in boron concentrations in MW-07S during the 2007 to 2010 timeframe. Three wet scrubbers were added at the Marshall facility in October 2006 through May 2007 which corresponds with the increase in boron concentrations. Such a sharp increase in concentration should have been a warning to DEC of groundwater deterioration during this timeframe which should have resulted in evaluation of the source and extent of the impacts.



In 2007, wells MW-06S/D through MW-09S/D were included in the sampling events. MW-07S and MW-07D were installed downgradient of the ash basin, along the ash basin waste boundary. Iron and manganese in MW-07D and boron, total dissolved solids, cobalt, and manganese in MW-07S were detected above the 2L Standards and IMAC since the first sampling event in which the compounds were included. Chloride was also detected in MW-07S above the 2L Standards from 2008 through 2010, and remained at elevated concentrations comparable to the 2L Standard through 2019. Similarly, elevated concentrations of chloride were also detected in MW-07D.

MW-10S/D through MW-14S/D were installed along the compliance boundary in 2011. Iron and manganese in MW-8D, MW-8S, and MW-14S, and manganese in MW-06S and MW-09D were detected at concentrations exceeding the 2L Standards from the initial sampling event in each well to 2019. Manganese concentrations in Site wells are shown on the graph below in comparison to background and the 2L Standard. Please note, the concentrations on the vertical axis are show on a logarithmic scale.



Cobalt was detected in compliance boundary wells MW-14D and MW-14S from 2015 to 2019 above 2L Standards, and boron in MW-14D and MW-14S and sulfate in MW-14S were detected above 2L Standards from 2011 through 2019. TDS was also detected in MW-14S above 2L Standards from 2011 through 2015. Iron, manganese, boron, sulfate, and cobalt were all detected below 2L Standards or the IMAC in the background monitoring wells.

In 2015, additional background wells were installed at the site including BG-1S/D, BG-2S/BR, BG-3S/D/BR, BWA-4S/D through GWA-6S/D, GWA-8S/D, GWA-12S/BR. In 2017, DEC established BTVs for the Site. Historical concentrations exceeded the BTVs for multiple metals.

XI. RIVERBEND STEAM STATION

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The Riverbend facility began operation in 1929. In 1957, the plant began wet sluicing CCRs to an ash basin. In 1979, the ash basin was divided and vertically expanded to form what are known as the Primary Ash Basin and the Secondary Ash Basin which total approximately 69 acres. During operation, the ash basins received sluiced CCRs until the plant was retired in 2013. The facility never converted to dry ash handling. A cumulative amount of approximately 3 million cubic yards of CCR materials were placed in the basins.

As a result of the Dan River release, DEQ issued a directive for an excavation plan to close the ash basins at the Riverbend facility on August 13, 2014, and basin closure was completed in March 2019. In March 2015, DEC pleaded guilty to criminal negligence in Federal Court for violating the Clean Water Act by allowing discharge of contaminated water with elevated levels of arsenic, chromium, cobalt, boron, barium, nickel, strontium, sulfate, iron, manganese and zinc from a coal ash basin at the Riverbend facility into an unpermitted channel which was discharged to the Catawba River from at least November 2012 to December 2014.

In addition to CCRs, prior to closure, the ash basins managed other wastewaters including metal cleaning wastes, other cleaning waters, coal pile runoff, groundwater remediation wastewater, cooling water, stormwater, groundwater from a track hopper sump, lab drain and chemical makeup water, tank and drum rinse waters, treated sanitary wastewater, and vehicle rinse water.

Q. PLEASE DISCUSS WHEN DEC BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY? PLEASE BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY (METALS OF CONCERN, GROUNDWATER FLOW, CONCENTRATION TRENDS OVER TIME, ETC.).

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

- Groundwater sampling began in 2008 at voluntary wells within the compliance boundary. Manganese (up to 33,800 µg/L) and iron (up to 3,300 µg/L) were detected at concentrations substantially exceeding the 2L Standards in multiple wells. No background well was installed at this time.
- Although concentrations within the compliance boundary indicated 2L Standard exceedances, no additional sampling or installation of wells along the compliance boundary was completed by DEC until requested to do so by DEQ.
- In 2010, wells were installed along the compliance boundary and sampling over time indicated that concentrations of iron (up to 37,700 µg/L) and manganese (up to 11,200 µg/L) were detected above 2L Standards and background levels in downgradient compliance boundary wells.

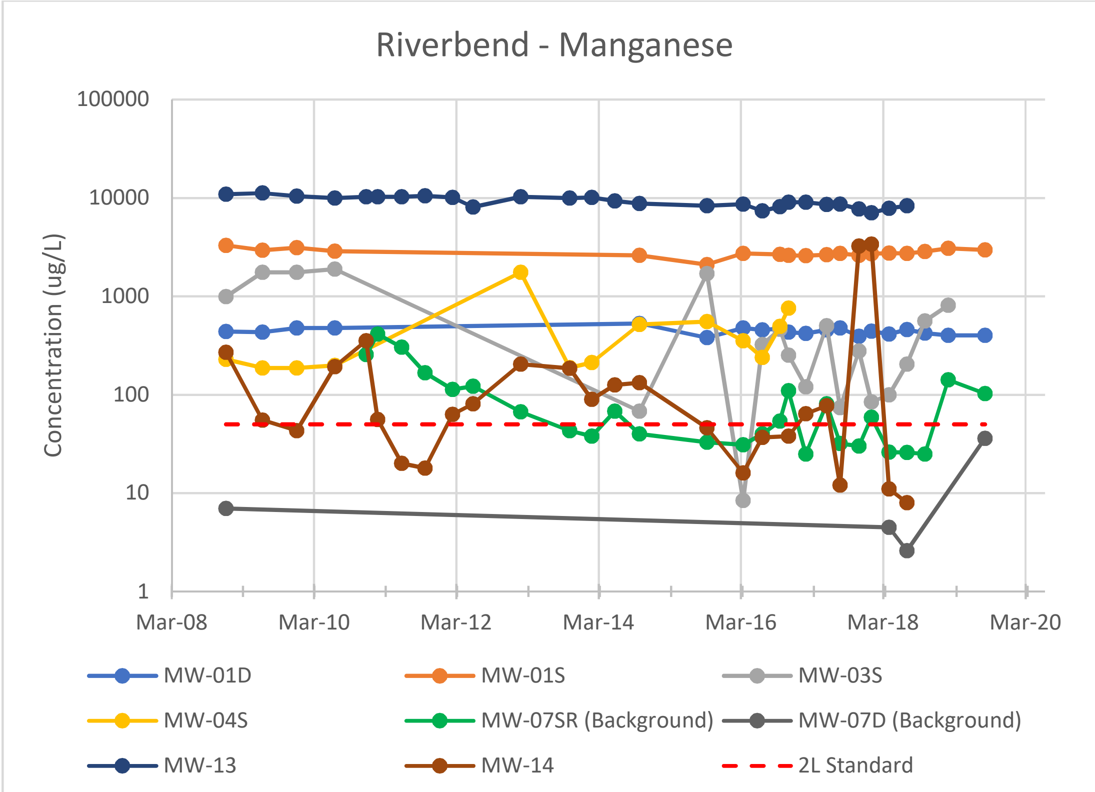
- In 2015, cobalt and vanadium were added as analytes and detected at concentrations exceeding the IMACs. Cobalt was detected at concentrations up to 29.2 µg/L versus the IMAC of 1 µg/L and vanadium was detected at concentrations of 2.7 µg/L versus the IMAC of 1 µg/L.

Voluntary groundwater monitoring began at the Riverbend facility in 2008 in wells MW-1S/D through MW-6S/D. Site maps showing the well locations and groundwater flow are included as Hart Exhibit 46A and an Excel spreadsheet of groundwater data for the Site is included as Hart Exhibit 46B.

All the wells were located along or slightly outside the ash basin waste boundary and downgradient of the Primary and Secondary Basins. Manganese was detected in MW-1D, MW-1S, MW-03S, and MW-04S at concentrations exceeding the 2L Standard between 2008 and 2019. In addition, iron in MW-01S from 2008 through 2019 and in MW-04D and MW-04S at multiple sampling events between 2008 and 2017 was detected at concentrations exceeding the 2L Standards. No background wells were installed at this time.

In 2010, wells MW-7SR and MW-7D through MW-15 were installed along the compliance boundary. MW-7SR and MW-7D were installed on the upgradient side of the compliance boundary to establish Site-specific background concentrations for the Site. Isolated 2L exceedances of iron and manganese were detected in MW-07SR with a maximum iron concentration of 6,500 µg/L and a maximum manganese concentration of 413 µg/L.

Concentrations of iron and manganese in MW-01S and MW-04S and manganese in MW-01D and MW-03S exceeded the 2L Standards from 2008 through the most recent sampling event at each well and were higher than background concentrations between 2015 and 2019. Additionally, iron was detected in MW-09 inconsistently from 2010 through 2019 at concentrations above the 2L Standard and background concentrations. Iron and manganese were detected in MW-13 at concentrations above 2L Standards and substantially greater than background concentrations between 2010 and 2019. Iron was detected at a maximum concentration of 37,700 µg/L and manganese was detected at a maximum concentration of 11,200 µg/L in MW-13. Manganese concentrations detected at the Site are shown on the graph below. Please note, the concentration scale on the vertical axis is a logarithmic scale because of levels greater than 10,000 µg/L in well MW-13.



Cobalt was detected in MW-01S, MW-05S, and MW-13 at concentrations exceeding the 2L Standard from 2015 to 2019, and well above background concentrations during that time period. MW-14 indicated concentrations of iron and manganese at concentrations exceeding the 2L Standard, but consistent with background concentrations. Vanadium was included as a sample analyte from 2015 through 2019, and was detected above the IMAC and background concentrations in MW-01D, MW-02D, MW-03D, MW-04D, MW-05D, MW-06D, MW-08D, MW-09, and MW-14.

In 2015, additional background wells including BG-1, BG-4, BG-5, and GWA-14S were used along with MW-7SR/D to determine BTVs. Historical downgradient concentrations were in excess of the BTVs.

XII. WS LEE STEAM STATION

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The initial ash basin at the WS Lee facility was constructed in 1951 and is referred to as the Inactive Ash Basin. This basin is approximately 17 acres and received approximately 1 million cubic yards of sluiced CCRs cumulatively from 1951 to 1974 when it reached capacity. Additional ash basins, referred to as the Primary and Secondary Ash Basins, were constructed in 1974 and 1978, respectively. These basins were approximately 41 acres and 23 acres respectively and received sluiced CCRs until November 2014. The cumulative amount of CCRs placed in these basins were approximately 1.9 million cubic yards.

In 2014, DEC entered into a Consent Agreement with DHEC to close the ash basins and an old ash fill area. In 2015, DEC began to excavate CCRs from the Inactive Ash Basin to dispose of it off-site. The closure plans for the other two basins include the removal of CCRs from the Secondary Ash Basin and placement in the Primary Ash Basin; the construction of a permitted landfill in the footprint of the Secondary Ash Basin, and then the excavation of the CCRs from the Primary Ash Basin and placement of it into the new landfill. Preparation work for these activities is on-going.

In addition to CCRs, the ash basins received other wastewaters including chemical metal cleaning waste, coal pile runoff, blowdowns, water treatment system waters, and pollution control wastewaters. After 2014, the

Primary and Secondary Ash Basins only received wastewater from the active combined cycle plant and other facility wastewater.

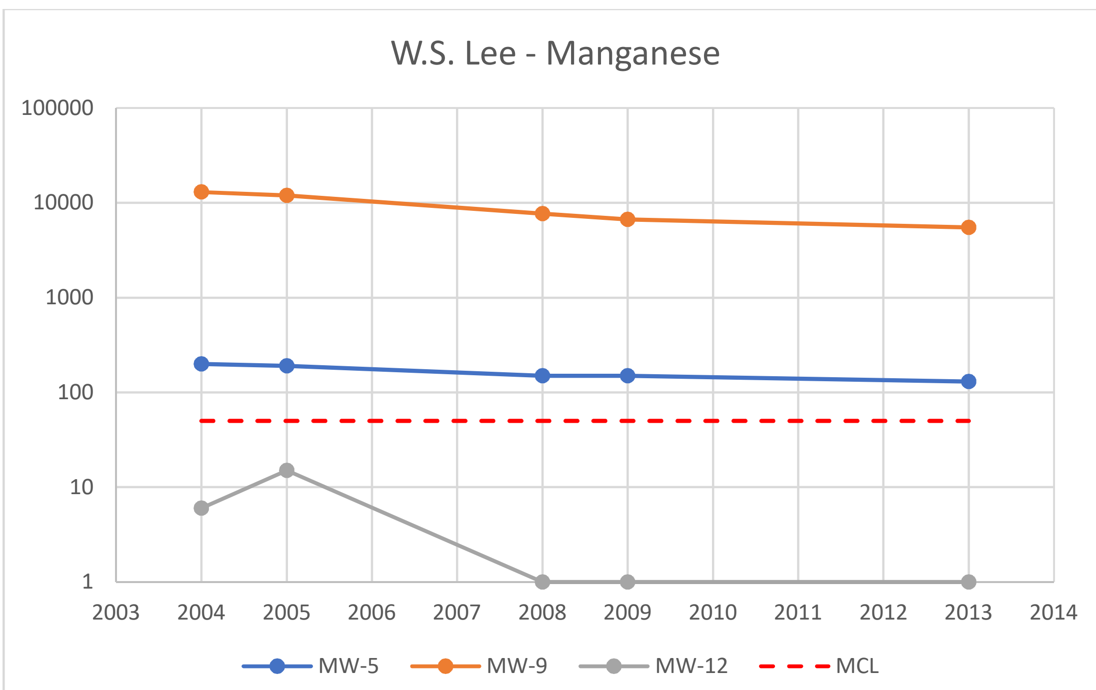
Q. PLEASE DISCUSS WHEN DEC BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

- The WS Lee began groundwater sampling in 1993. In the earliest reviewed data from 2004, sulfate (up to 273 mg/L), iron (up to 21,000 µg/L), and manganese (up to 13,000 µg/L) were detected downgradient of the ash basin at concentrations exceeding the MCLs.
- Sometime before 2009, additional wells were installed around the ash basin. Manganese (up to 6,700 µg/L) was detected above the MCL in wells located crossgradient and downgradient of the basin.
- Boron (up to 2,200 µg/L) was also detected at elevated concentrations in wells downgradient of the ash basin.
- Although concentrations in downgradient wells exceeded MCLs and were elevated when compared to concentrations in upgradient wells, DEC did not take any voluntary steps to reduce groundwater impacts.

Groundwater monitoring at the WS Lee Station began in 1993 with four groundwater monitoring wells. In 2009, additional groundwater wells were installed. Site maps showing the well locations and groundwater flow and data summary tables from the reviewed reports are included as Hart Exhibit 55.

In the earliest reviewed groundwater data from 2004, iron and manganese in MW-9 and manganese in MW-5 were detected above the MCL. The wells are located downgradient of the active ash basins. The iron (21,000 µg/L) and manganese (13,000 µg/L) concentration in MW-9 was substantially higher than the concentration in upgradient well MW-12 (6 µg/L). In following years, concentrations of iron and manganese in MW-9 and manganese in MW-5 continued to exceed the MCLs and were significantly higher than upgradient concentrations. A graph of manganese concentrations in MW-5 and MW-9 compared to concentrations in upgradient well MW-12 is included below. Please note the vertical axis is shown with a logarithmic scale.



Sulfate was also detected at concentrations exceeding the MCL in MW-9 from 2004 to 2008. Concentrations remained elevated until 2013. Similarly, high concentrations were detected in MW-5 from 2004 to 2013, although the concentrations did not exceed the MCL.

In data reviewed from 2008, boron was included as an analyte. Although no MCL is established for boron, the concentrations in upgradient and downgradient wells could be compared. Boron was not detected in the upgradient well MW-12, but it was detected at concentrations up to 1,600 µg/L(MW-17) in downgradient wells in 2008. Concentrations in downgradient wells remained elevated until 2013. In cases where there is no MCL, DHEC typically uses the EPA tap water Regional Screening Level (RSL)[9] to evaluate if compounds are present at levels of concern. The EPA tap water RSL for boron is 400 µg/L.

When additional wells were installed in 2009, manganese was detected above the MCL in the new wells located crossgradient or downgradient of the ash basins. Although concentrations in downgradient wells exceeded MCLs and were elevated when compared to concentrations in upgradient wells, DEC did not take any voluntary steps to reduce groundwater impacts.

XIII. RESPONSE ACTIONS

Q. BASED UPON YOUR ANALYSIS, BEFORE THE DAN RIVER SPILL HAPPENED, DID DEC UNDERTAKE REASONABLE AND PRUDENT

[9] https://semspub.epa.gov/work/HQ/199628.pdf

ACTIONS AND PRACTICES IN A TIMELY MANNER TO RESPOND TO GROUNDWATER CONTAMINATION AT ITS ASH BASINS AND ADDRESS CLOSURE OF ITS COAL ASH BASINS?

A. No. A summary of my conclusions regarding this question is provided below.

1. The utility industry, including DEC, knew about the potential for contamination of groundwater from coal ash basins as early as the 1980s.
2. At some DEC facilities, groundwater monitoring had been conducted as early as the early 1990s which indicated groundwater contamination issues with coal ash basins.
3. By the early 2000s, as a result of EPA's Regulatory Determination, it was clear that there were documented damage cases from coal ash basins and that EPA assessments of environmental impact would lead to potential closure of ash basins.
4. DEC documents indicate that by 2003, DEC knew about the changing regulatory environment with regard to coal ash basins and that addressing the basins by performing groundwater monitoring and considering dry ash conversions would reduce long term risks and liabilities and identify problems up front, but would also result in increased costs.
5. In addition to sluicing coal ash, DEC directed other wastewater streams to the basins over time so that the basins became a favored location to discharge its wastewaters, and it did so without evidence of how some

of those additional waste streams, such as advanced air pollution control equipment, would impact the basins and groundwater. For example, there is evidence that the later addition of FGD wastewaters contributed to additional groundwater impacts.

6. In 2004 through 2008, DEC implemented voluntary groundwater monitoring at its ash basins as part of the USWAG effort to address EPA's concern about coal ash basins. DEC indicated to DEQ that it wanted to be proactive and address groundwater concerns up front in advance of the USWAG action plan and indicated that groundwater monitoring wells would be installed by 2006. DEC's participation in this program should be acknowledged as a responsible step; however, implementation of groundwater monitoring was not performed at several facilities until 2008 despite the fact that data collected from the initial facilities in 2004 to 2005 as part of USWAG indicated groundwater impacts at the coal ash basins.

7. Even after the groundwater data was collected, DEC did not follow the USWAG action plan about how to respond if, after evaluating the data against background, groundwater impacts were detected. The USWAG action plan indicates that, on detecting groundwater impacts, DEC should have worked with the regulatory agency to further assess conditions and, as needed, develop corrective action programs. Instead, DEC just submitted the data to DEQ without evaluation and implied in the reports that the data were consistent with background conditions.

8. The detections above 2L Standard exceedances within the compliance boundary at North Carolina DEC facilities or MCLs at the South Carolina DEC facility should have triggered a real evaluation of background conditions, installation of wells at the compliance boundary (which is the only way to determine compliance with the groundwater standards), and additional monitoring wells to define the extent of impacts once detections above the 2L Standards were confirmed. This should have started for multiple facilities by the 2005/2006 timeframe. However, rather than being proactive with regard to groundwater contamination at its coal ash basins, DEC chose to wait until regulatory agencies identified groundwater contamination concerns from the brief DEC data submittals. Even after wells were installed along compliance boundaries at DEQ's direction in 2011, DEC continued to indicate as late as 2013 that it strongly believed that the iron and manganese exceedances were the result of background concentrations and that these compounds only had secondary MCLs (implying that they were not a concern), despite the fact that the actual data did not support them being consistent with background and that secondary MCLs have no relevance to groundwater standards.

9. Despite knowledge of groundwater contamination at its coal ash basins and the changing regulatory environment which would almost certainly require closure of the basins if groundwater impacts were identified, DEC made little effort to develop plans and preparation for closing the

ash basins until it was forced to do so after the Dan River release and subsequent CAMA and CCR regulations.

Q. MR. HART, WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to provide my analyses regarding system costs that should be disallowed for 1) costs related to connections to alternate water supplies and 2) a minimum adjustment for several points of time by estimating the inflation in cost between the time DEC knew or should have known to take further action to address groundwater contamination at the basin.

Q. HOW WOULD COSTS THAT DEC IS SEEKING FOR COAL ASH RELATED ACTIVITIES LIKELY BE DIFFERENT TODAY IF DEC HAD INITIATED ACTIONS SOONER TO ADDRESS ITS ASH BASIN PRACTICES?

A. Based upon the identification of groundwater impacts associated with the coal ash basins, DEC should have taken prompt action to increase monitoring and responsive action at specific sites. Further, with the changing regulatory environment, and Duke Energy's stated policy regarding the CCR rules and corrective action associated with ash basins that had groundwater contamination, DEC should have initiated a systematic plan much sooner than it did to address its coal ash basins by beginning the process of converting facilities to dry ash handling, eliminating other wastewater streams that were being placed into the basins, developing basin closure plans, and evaluating methods to reduce the environmental impact while the basins were still operational. Duke Energy's own position in 2011 comments on the 2010 draft CCR rules indicated that it supported groundwater monitoring at facilities, and any unit not in compliance would need to take corrective action to come into compliance or implement a closure plan. However, this did not occur within a reasonable timeframe after groundwater contamination was identified at its facilities.

DEC's inattention to problems and delay in responsive actions increased the cost today:

- DEC's actions and failure to take actions before the Dan River spill prompted the adoption of environmental requirements that imposed accelerated schedules to address coal ash basin problems, particularly at Dan River and Riverbend, and costs for accelerated actions are almost always greater than costs under non-accelerated timeframes.
- Further, DEC's admission that it was criminally negligent in how it managed some sites likely prompted a lack of confidence by regulators and the public that less costly actions would be effective, and prompted requirements that DEC take more extensive and high-cost approaches, such as the high-cost beneficiation requirement.
- Most of the expenditures that DEC seeks to recover for coal ash basin closures and CCR disposal were incurred at coal plants that are retired and have not been used for several years to produce power for ratepayers. Had DEC taken actions sooner to address its coal ash basins

by engaging in reasonable monitoring and taking adequate responsive actions, some of the costs would have been included in the cost of service for customers while the coal plants were in use.

- DEC's costs are higher today due to inflation.
- The requirement that Duke connect all households to alternate water supplies was likely a result of DEC's delay in addressing groundwater impacts. It is unheard of for a company to have to connect properties to alternate water when those water supplies are not impacted, as is maintained by DEC. In my opinion, this was warranted by law because DEC, once it knew it had groundwater issues, failed to determine the extent of groundwater impacts, reliably establish background concentrations, and perform adequate receptor evaluation. Instead, DEC contended that there were no water supply well receptors in the area of its facilities and maintained that position despite there being no indication that it performed comprehensive receptor surveys until required to do so under CAMA. Thus, it appears that these costs were directly related to DEC's delay in evaluating groundwater impacts. Therefore, I believe that $17,527,070 related to connection to alternate water supplies should not be included in the recovered costs.
- The analysis of specific costs that DEC would have incurred had it responded earlier to the presence of groundwater impacts at its coal ash basins is difficult. This is because it is difficult at this point in time to retroactively determine what costs would have been incurred 10 or more

years ago and because some of the costs would have resulted in additional costs that would also have to be accounted for. For example, conversion to dry ash handling would have led to increased costs to transport ash to an off-site or on-site landfill. Therefore, I cannot provide line-by-line estimates of earlier costs. However, I can reasonably estimate the reduction in costs if DEC had responded earlier to the presence of groundwater impacts at its coal ash basins by assuming the activities that DEC is requesting cost recovery for at this time are similar to the activities that would have been conducted at an earlier time and then considering the time value of money between the time when DEC knew it had issues with groundwater contamination and when it started planning for basin closure in 2014. These calculated costs are likely to underestimate the actual potential cost reduction because lower cost options would likely have been available at those earlier times than are being implemented at present. Because DEC was aware of the issues with groundwater contamination at its ash basins as early as the late 1980s and continued through 2014 and beyond when it started substantial planning for basin closure, I calculated the approximate reduction in costs from the current requested costs considering 1) removal of the water supply connection costs of $17,527,070 as discussed above, and 2) the time value of money starting at different points from the late 1980s until 2010:

- 1989 (groundwater contamination was first documented)- $190 million (MM)
- 1993 (groundwater contamination detected at two additional facilities (Dan River and WS Lee) and just before notice to insurance carriers of contamination above standards at Allen, Belews Creek, Dan River, Marshall, and WS Lee) - $140MM
- 2003 (internal documents demonstrating DEC's knowledge of groundwater contamination issues, possible need to limit or stop sluicing ash to basins, and need to develop consistent and measured approach to address groundwater contamination) - $100MM
- 2010 (DEQ's intervention to groundwater data collected by DEC as part of USWAG action plan) - $50MM

- The above costs are calculated by taking the entire requested amount for coal ash basin closure of $405,957,531 and removing the alternate water supply costs mentioned above and the Charah contract termination fee of $46,329,946 (the Charah costs are a contract issue so I am not indicating that it should or should not be included; I simply excluded it from my analysis). This results in a cost of $342,100,515. I then used the average inflation rate from the particular start time noted above to 2014 to account for the DEC delay in addressing the ash basins until 2014. The average rates of inflation used in the calculations are as follows:

- 1989-2015: 2.7%
- 1993-2015: 2.3%
- 2003-2015: 2.2%
- 2010-2015: 1.8%

This results in the above-mentioned reduction of costs.

- Please note that the starting point for my evaluation of $405,957,531 is for DEC's system costs related to coal ash basin closure according to Ms. Bednarcik's direct testimony. These costs do not include costs for capital expenditures that are required for coal ash basin closure such as dry ash conversion costs, installation or rerouting of piping for other wastewater streams prior to closure, retention ponds for other wastewaters, and/or treatment systems for wastewaters that could no longer be placed in the ash basin ponds, etc.
- In summary, at a minimum, if DEC had started the process of closing its ash basins earlier as a result of the identification of groundwater contamination, DEC's recoverable costs for the system would be reduced by approximately $50MM to $190MM.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1214A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	)	**ATTORNEY GENERAL'S OFFICE'S CORRECTIONS TO DIRECT AND SUPPLEMENTAL TESTIMONY OF STEVEN C. HART, PG**

CORRECTIONS TO THE DIRECT AND SUPPLEMENTAL TESTIMONY OF STEVEN C. HART, PG

Mr. Hart's direct testimony should be corrected as follows:

1. Page 14, line 16 – "corrective action plans" should be changed to "groundwater assessment report."
2. Page 31, line 23 – the word "NOT" should be inserted between the words "were" and "upgradient."
3. Page 57, line 8 – the word "be" should be changed to "by."
4. Page 73, line 4 – the number "40B" should be changed to "48" and the number "46B" should be changed to "55."
5. Page 78, line 1 – the number "200" should be changed to "300."
6. Page 81, line 7 – the word "fly" should be changed to "bottom."
7. Page 122, line 2 – the number "55" should be changed to "47."

Mr. Hart's supplemental testimony should be corrected as follows:

1. Supplemental pages 126-131 should be renumbered as pages 127-132 and should be substituted for the pages at the end of Mr. Hart's direct testimony,

starting with page 127 and going to the end, in order to constitute Mr. Hart's entire written testimony.

Summary of STEVEN C. HART, PG
in
Duke Energy Carolinas, Docket No. E-7, Sub 1214

My name is Steven Hart and I am testifying on behalf of the North Carolina Attorney General's Office with regard to coal ash basin closure-related costs incurred in the timeframe for which Duke Energy Carolinas (DEC) is seeking cost recovery in this rate case – January 2018 through January 2020. I am the President and Principal Hydrogeologist of the environmental consulting and engineering firm Hart & Hickman, PC, which has offices in Charlotte and Raleigh. I am, by education, training, and experience an environmental scientist and hydrogeologist. I am a Licensed or Professional Geologist in a number of states including North Carolina and South Carolina. I have over 30 years' experience assessing and remediating contamination of environmental media such as soil and groundwater primarily in North Carolina and South Carolina, but also throughout the United States. I frequently provide consulting services to clients on regulatory compliance issues with regard to soil, sediment, surface water, and groundwater contamination.

My testimony focuses primarily on answering the following questions:

First, given the information that DEC knew or that was reasonably discoverable to DEC with regard to groundwater conditions at its coal ash basins prior to the adoption of specific regulatory requirements in North Carolina's Coal Ash Management Act ("CAMA") in 2014 and the Environmental Protection Agency's (EPA's) Coal Combustion Residuals (CCR) regulations in 2015, did DEC undertake reasonable and prudent actions and practices in a timely manner to address storage and disposal of CCR and closure of its coal ash basins before the Dan River release occurred in 2014?

Second, how would costs that DEC is seeking for coal ash-related activities likely be different today if DEC had initiated actions sooner to address its ash basin practices?

Groundwater contamination from unlined coal ash basins such as those present at the DEC facilities results from multiple factors, including the presence of high concentrations of metals which can leach from the coal ash into groundwater, the presence of a higher hydraulic head in the ash ponds as compared to groundwater which drives metals present in the coal ash basins into groundwater, and changes in groundwater chemistry that occur from the presence of the ash basin which can enhance the solubility and mobility of metals.

Once groundwater contamination is detected, North Carolina has specific rules that address the assessment and remediation of contamination known as the "2L Rules". The 2L Rules were first promulgated in 1979 and include numerical standards for compounds known as the "2L Standards". In accordance with the 2L Rules, concentrations above the 2L Standards warrant action including notification to the Department of Environmental Quality ("DEQ"), establishing background concentrations for naturally occurring compounds, termination and control of the source or sources causing the violation, mitigation of hazards from exposure to the pollutants, and corrective action to restore the quality of groundwater to the standards.

The knowledge base concerning the impact to groundwater from unlined coal ash basins increased over time from the 1980s to the mid-2000s. The utility industry, including DEC, knew about the reasonable potential for contamination of groundwater from coal ash basins as early as the 1980s. At the Belews Creek and Dan River DEC facilities, groundwater monitoring was conducted in the early 1990s and indicated groundwater contamination issues with coal ash basins at those facilities. By the early 2000s, as a result of an EPA Regulatory Determination concerning the management of CCRs, it was clear that EPA's documentation of damage cases from coal ash basins and their assessments of environmental impact would lead to increased scrutiny, environmental sampling, and potential closure of ash basins. DEC documents confirm that, by 2003, DEC knew about the changing regulatory environment with regard to coal ash basins and that addressing the basins by performing groundwater monitoring and considering dry ash conversions would reduce long term risks and liabilities and identify problems up front.

In 2006, the Utility Solid Waste Activities Group (USWAG), of which DEC was a part, issued an "action plan" to address EPA's concern about groundwater impacts from coal ash basins. The USWAG action plan was the electric utility industry's <u>commitment</u> to adopt groundwater performance standards at facilities that manage CCRs and to implement a comprehensive monitoring program to measure conformance with the groundwater standards at facilities that managed CCRs in an effort to avoid mandatory federal requirements..

In 2004 through 2008, DEC implemented groundwater monitoring at its ash basins as part of the USWAG action plan. Most of the groundwater monitoring was performed within the compliance boundary of the coal ash basins at the North Carolina facilities. The results of this monitoring provided irrefutable evidence of groundwater impacts associated with the coal ash basins. The USWAG action plan indicates that, on detecting groundwater impacts, DEC should have worked with the regulatory agency to further assess conditions and, as needed, develop corrective action programs. Instead, DEC submitted the data to DEQ without evaluation or responsive action and implied that the data were consistent with background conditions, even though that implication was not supported by the data.

The detection of compounds above 2L Standards in groundwater near the coal ash basins at North Carolina DEC facilities or MCLs at the South Carolina DEC facility should have triggered a real evaluation of background conditions, installation of wells at the compliance boundary for the North Carolina facilities, and additional monitoring wells to define the extent of impacts. However, rather than being proactive with regard to groundwater contamination at its coal ash basins, DEC chose to wait until regulatory agencies noted groundwater contamination concerns from DEC's data submittals in the 2009 to 2010 timeframe. This is despite that fact that, at several facilities, there were dramatic increases in concentrations of compounds in groundwater between the initial well sampling and the 2010 timeframe.

Even after wells were installed along the mandatory compliance boundaries of the ash basins at DEQ's direction in 2011, DEC continued to indicate as late as 2013 that it strongly believed that the iron and manganese exceedances were the result of background concentrations. However, the actual data did not support the conclusion that the exceedances were consistent with background concentrations.

It is evident from my analysis that, as a result of groundwater monitoring data and increased concern with groundwater contamination from coal ash basins, DEC should have taken responsive action sooner and initiated a systematic plan to address its coal ash basins by converting facilities to dry ash handling, eliminating other wastewater streams, closure planning, and evaluating methods to reduce environmental impact while the basins were still operational. This would have required an expenditure of funds earlier, but would have reduced long term risks and liabilities which would have led to lower costs being requested at this time and the imposition of those costs on DEC's ratepayers at that time.

In 2013 and 2014, Duke Energy documents acknowledged that DEC did not yet have any approved closure plans and that it had failed to make "reasonable efforts" toward the closure of ash basins. It was not until after the Dan River release in February 2014 that DEC committed, under regulatory pressure, to implement full assessments, closure evaluations, some dry ash handling conversions, and closure activities on an expedited basis.

As a result of the Dan River release, North Carolina enacted CAMA in 2014. Soon thereafter, in 2015, EPA issued its CCR Rule. Both of these regulations address closure of coal ash basins and bring greater certainty about the management and closure of coal ash ponds in compliance with Groundwater, Surface Water, and Solid Waste requirements. However, for many years prior to these newer requirements, there was no ambiguity about the requirements of North Carolina's 2L Rules. When groundwater contamination is detected in association with a permitted ash pond – i.e., .if a 2L Standard for a compound is exceeded -- the 2L Rules require that the responsible party determine the nature and extent of the contamination, terminate and control the discharge, mitigate hazards, perform receptor surveys to identify potential receptors of the contamination, and propose and implement corrective actions.

DEC's inattention to groundwater contamination issues and delay in responsive actions to its coal ash basins prior to the Dan River release increased the cost today as follows:.

1) DEQ imposed accelerated schedules to address coal ash basin problems, particularly at Dan River and Riverbend, and costs for accelerated actions are almost always greater than costs under non-accelerated timeframes.
2) Most of the expenditures that DEC seeks to recover for coal ash basin closures and CCR disposal were incurred at coal plants that are retired and have not been used for several years to produce power for ratepayers. Had DEC taken actions sooner to address its coal ash basins by engaging in reasonable monitoring and taking adequate responsive actions, some of the costs would have been included in the cost of service for customers while the coal plants were in use.

3) The requirement that DEC connect all households to alternate water supplies within the area of each North Carolina plant was likely a result of DEC's delay in addressing groundwater impacts. Although DEC maintains that those water supplies were not impacted by groundwater contamination from ash ponds, it is unheard of for a company to have to connect properties to alternate water when the water supplies have not been impacted. In my opinion, the requirement that DEC provide alternate water supplies was warranted because DEC, once it knew it had groundwater issues, failed to determine the extent of groundwater impacts, reliably establish background concentrations, and perform an adequate receptor evaluation.
4) In the absence of an indication that DEC accrued and set aside monies for these activities, DEC's costs are higher today due to inflation.

The determination of the increased costs that DEC incurred as a result of its delays in corrective action is difficult to determine because of the number of factors involved. Therefore, I used a simplified approach by 1) removing the water supply connection costs as discussed above, and 2) assuming the activities that DEC is requesting cost recovery for at this time are similar to the activities that would have been conducted at an earlier time. Then I de-escalated the cost by considering the inflation rate between the time when DEC knew it had issues with groundwater contamination and when it started planning for basin closure in 2014. These calculated costs are likely to underestimate the cost reduction because lower cost options would have been available at those earlier times than are being implemented at present. The calculated cost reduction ranges from $50 million if DEC had started closure planning in 2010 to $190 million if DEC had started planning in 1989.

This concludes my summary. Thank you very much.

MS. TOWNSEND: Madam Chair, Mr. Hart is now available for cross examination.

CHAIR MITCHELL: All right. Public Staff?

MS. LUHR: Apologies. The Public Staff has no questions for Mr. Hart.

CHAIR MITCHELL: All right. Duke?

MR. MEHTA: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. MEHTA:

Q Good morning, Mr. Hart.

A Good morning.

Q Mr. Hart, we'll be referring to a number of exhibits, but one I know we'll be referring to in particular is your -- a transcript of your deposition which was taken on, I think, the second of March, which was previously marked as Duke Exhibit 4, DEC Exhibit 4. So if you could just have that handy, that would be really good.

MR. MEHTA: And Chair Mitchell, I would like to go ahead and identify for the record DEC Exhibit 4 as Hart DEC Cross Examination Exhibit Number 1.

CHAIR MITCHELL: All right. Bear with me one minute, Mr. Mehta, while I get the document. All right. The document will be so marked.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, DEC Hart Cross Examination Exhibit Number 1 was marked for identification.)

Q Mr. Hart, this is your first appearance before the North Carolina Utilities Commission, right?

A That is correct.

Q And I'm going to refer to it, I think, probably throughout this examination as the Commission, and you'll understand what I mean when I say the Commission, correct?

A Yes, I will.

Q And you understand, Mr. Hart, that the Commission is not an environmental regulator; is that right?

A That is my understanding, yes.

Q And, in fact, Mr. Hart, in -- in North Carolina, the environmental regulator for Duke Energy Carolinas is the North Carolina Department of Environmental Quality, correct?

A That and EPA, yes.

Q And if I refer to the North Carolina Department as the DEQ, no matter what its name was at whatever the time frame was in which we're talking about it, you will understand what I'm talking about, correct?

A Correct.

Q The Utilities Commission does not regulate coal ash storage or disposal, does it?

A I don't know that.

Q Well, look, if you would, Mr. Hart, at DEC Exhibit 7.

MR. MEHTA: Chair Mitchell, I would like for DEC Exhibit 7 to be identified for the record as Hart DEC Cross Examination Exhibit 2.

CHAIR MITCHELL: All right, Mr. Mehta. We will identify the document as DEC Hart Cross Examination Exhibit 2.

(Whereupon, DEC Hart Cross Examination Exhibit Number 2 was marked for identification.)

Q Mr. Hart, what is now marked and identified as DEC Cross Examination Exhibit 2 is actually directly from the Commission's website. Do you see that?

A I see a copy of it, yes.

Q And there's two columns at the top of the page under the heading Electricity. Do you see that?

A Yes.

Q The one on the left says the NCUC, which is the Commission, Regulates, and the one on the right says the

NCUC Does Not Regulate. Do you see that?

A Yes. I do see that.

Q And there is a number of bullets under the heading that it Does Not Regulate. The second-to-last bullet is that the Commission does not regulate coal ash storage or disposal. Do you see that?

A Yes.

Q And right under that, the Commission also does not regulate air or water emissions from power plants. Do you see that?

A Yes.

Q And both of those things, Mr. Hart, are the responsibility, in terms of regulation of DEC in North Carolina, the responsibility of the DEQ, correct?

A I would say the DEQ and the United States Environmental Protection Agency, yes.

Q Okay. And just to be clear, I guess the EPA delegates to the DEQ watch authority that the EPA has with respect to coal ash or water emissions from power plants. Am I understanding that correctly or am I wrong about that?

A Well, they do for the most part, but, for example, the Dan River spill, of course, EPA was heavily involved with, and it's certainly related to coal ash storage and disposal and releases. So there are cases where the EPA feels like they need to be involved, and they may come and join in with the DEQ to address certain issues.

Q I understand, but in the sort of normal everyday run-of-the-mill operation of the power plants that are run by DEC, the DEQ has delegated authority from the US EPA to oversee and regulate the operation of the power plants, correct?

A I would say from an environmental standpoint, for the most part, yes.

Q And in terms of water emissions from the power plants, that regulation occurs in the context of a permit program, correct?

A Could you explain what you mean by "water emissions"?

Q Well, I guess what I mean is the -- let me back up and say it this way. There is a program called the National Pollutant Discharge Elimination System, or NPDES, correct?

A That is correct.

Q And that program is administered in North Carolina by the DEQ, correct?

A Correct.

Q And the Duke Energy Carolinas power plants, and we're really talking about the coal-fired power plants in terms of what we're talking about today, to the extent that they operate with NPDES permits, that program is administered and regulated by the DEQ; is that correct?
A Yes, with authority from the EPA.
Q And that's a direct delegation of authority from the EPA, correct?
A That's my understanding, yes.
Q Now, Mr. Hart, the Utilities Commission does not regulate groundwater quality, does it?
A I don't believe so.
Q And that also is the responsibility of the DEQ, correct?
A Correct.
Q And the Utilities Commission does not regulate when groundwater monitoring wells should be installed, where and to what depth they should be installed, or how frequently and for what parameters those wells should be sampled, does it?
A I don't believe so, no.
Q And those things also are the responsibility of the DEQ, correct, in North Carolina?
A Well, they would be the responsibility of the

Companies that are responding or addressing the environmental issues in accordance with the laws of the State of North Carolina, the environmental laws, which are overseen and -- by the DEQ.

Q Okay. So the DEQ is the regulator involved in issues of when groundwater -- groundwater monitoring wells should be installed, where and to what depth they should be installed, or how frequently and for what parameters those wells should be sampled, isn't it?

A No. I would disagree with that.

Q And you would disagree with that why?

A Well, the DEQ doesn't necessarily make those decisions. It's up to the individual company to make those decisions. In some cases, DEQ isn't involved at all in some of those decisions, except to the individual companies that are regulated by the groundwater standards or the surface water standards or something of that nature to determine, if we're talking about a groundwater issue, where to put wells, how deep to put wells, in accordance with the rules and in order to comply with the rules.

Q Do you -- are you saying that the DEQ has no involvement in those kinds of issues, Mr. Hart?

A No, I didn't. What I'm saying is, is that the

Companies have primary responsibility. The regulated people of the state have the primary responsibility to determine where to put wells, how deep to put the wells and those kind of things. The state might oversee and provide comments, but in most cases it's not a dictation of thou shalt do this. It's a self-implementing in some cases -- a groundwater assessment or remediation can be self-implemented. Certainly, there are procedures in place for the State to provide feedback, comments, and if not in compliance, notice of regulatory requirements or notices of violation, but it's not the sole responsibility of DEQ to make those decisions.

Q No. I understand, Mr. Hart, that it's not the sole responsibility of the DEQ to make those kinds of decisions, but it would be very foolish of a company to make those decisions on its own without involving the DEQ, would it not?

A No. In fact, there's certain programs within North Carolina like the Inactive Hazardous Sites Program, the Registered Environmental Consultant Program, where you get no feedback from DEQ with regard to where to put wells and you don't involve DEQ at all. And so it is not necessarily prudent to do that because you have an obligation to define the horizontal and vertical extent of groundwater contamination, you have an obligation to clean that groundwater contamination up, and so you may want to accrue those along the way, but it's not necessarily prudent to get approvals from the State in all steps of what you're doing.

Q Well, Mr. Hart, if you set aside the Inactive Hazardous Waste Program and the -- whatever you mentioned in terms of the -- of the process by which those decisions are made, and you just talk about the monitoring of groundwater in conjunction with NPDES permits that the DEQ has issued, which occurred at Duke Energy power plants, did it not?

A I'm sorry, I wasn't talking -- were you asserting I was talking about NPDES permits?

Q No. I think you said -- you mentioned that you were talking about there are programs in which the DEQ is not involved at all, like the Inactive Hazardous Waste Program, correct?

A Correct.

Q Okay. The Inactive Hazardous Waste Program has nothing to do with any of the groundwater monitoring that DEC did at its power plants, you know, back from the mid-1980s forward, does it?

A Not that I'm aware of, not DEC, no.

Q Okay. So if you set aside that self-executing program, the Inactive Hazardous Waste Program that you talked about, Mr. Hart -- and I take it you've advised clients in your -- in your role as a consulting hydrogeologist how to run a groundwater monitoring program, haven't you?
A Certainly, yes.
Q And you've done that in the -- in the context of the groundwater monitoring -- the same type of context of the groundwater monitoring that has gone on at DEC power plants since the mid-1980s, correct?
A Correct. Similar context, yes.
Q And is it your practice, Mr. Hart, to advise clients that in setting up a monitoring program in that context that they should ignore the environmental regulator?
A No. I never said they should ignore the environmental regulator, but you don't have to, every step along the way, get approval from DEQ. If you have a groundwater contamination, for example, you determine where the wells go, you determine where the spring intervals are, you determine the analyses. Now, that may be, in some cases, done in conjunction with DEQ, but if you find an issue, you send those in in a report,

typically, that identifies where you have contamination and it may recommend some additional assessment that needs to be done, but you, in general, in my experience, try to proactively deal with these issues. You don't just send in data and then sit back and wait for the regulars (sic) to come -- the regulators to come back and review it.

Q Mr. Hart, would you look at your Exhibit 28?

A One second. Okay.

Q Just tell me when you're there.

A Yes. I'm there.

Q And Exhibit 28 is an email from Allen Stowe at Duke Energy to various people reporting on groundwater well installation at the Allen Steam Station, and the email is dated August 13, 2004, correct?

A Correct.

Q And this -- this email is in the context -- and we'll get to this later, I think, in the examination, Mr. Hart, but in the context of the voluntary groundwater monitoring program that Duke Energy Carolinas implemented as part of the USWAG, and that's U-S-W-A-G, and you can remind me what the acronym stands for, if you would, Mr. Hart.

A It's the Utilities Solid Waste Activities

Group.

Q Thank you. So as part of that voluntary USWAG groundwater monitoring program, correct?

A Well, the -- as I understand it, the work they were doing at the Allen plant in 2004 was as part of the USWAG action plan.

Q Okay. And if you would, Mr. Hart, the second paragraph of the email notes -- well, actually, I believe the first paragraph, the very first line, notes that various people met with Bill Goforth of the DEQ, correct?

A Yes.

Q On August 12, 2004, correct?

A Correct.

Q And Mr. Allen (sic), in the second paragraph, you know, reports on that meeting, correct?

A Mr. Stowe?

Q Mr. Stowe. Excuse me.

A That's all right. Yes. Yes, he does.

Q And he says, "After a brief review of site maps by Bill Miller and Don Scruggs, a tour of the ash basin and the surrounding areas was given," correct?

A Yes. That's correct.

Q And he says, going forward, Mr. Goforth stated that the Company could, you know, investigate a certain area at the -- at the -- of the plant with -- "with minor modifications," correct?

A Well, he said, too, there are preexisting wells, so obviously there are wells already there that DEQ apparently didn't have any say in previously. So he says there are preexisting wells that could potentially be used in the USWAG monitoring plan, but also that he concurred with the location and proposed depths of some additional monitoring wells.

Q So that -- and that's in the following sentence. "Mr. Goforth concurred with the location and the proposed depths (well pair - one shallow, one deep) for the background and the two monitoring wells located closest to the locations where the ash basin is located near residences," correct?

A Correct. That's what it says, yes.

Q And it goes on to say that "Mr. Goforth requested that two additional monitoring wells be sited between the western side of the ash basin and the housing development" -- that NC; well, we'll just call it DEQ -- "and Gaston County officials will be contacted to ascertain" -- "permit requirements," et cetera. Do you see that?

A Yes.

Q So Mr. Goforth was consulted about the location of wells approved --
A Yes, yes.
Q -- in some -- in some fashion about the location, depth of the wells, correct?
A Yes, yes.
Q And suggested additional wells be placed in an additional site, correct?
A Correct.
Q And this is a very normal way that regulated entities interact with their regulators when deciding on a groundwater monitoring program, isn't it?
A It can be, yes. I think this is the only facility that they met with DEQ. That's the only facility that I have seen where they met with DEQ and discussed the well installation --
Q But you don't -- you don't --
A -- is the Allen plant.
Q You don't know if they also discussed the well placement with DEQ at the other facilities, do you? You don't know one way whether or not they ever met with DEQ with regard to well placement at the other facilities, do you?
A Well, like I said, I've seen no indication of

it, no. And, in fact, DEQ had a number of issues with the well placements when they submitted data in 2009. Some of the wells were not installed in upgradient locations. Some of the wells that DEC claimed were up -- back -- downgradient wells were actually upgradient. So it's hard for me to believe that DEC did, in fact, know about the location of all the wells that were installed because DEC -- DEQ, I'm sorry, actually asked for maps that shows where the well -- the locations of the wells were in 2009. They didn't know where these wells were being installed.

Now, they did get Mr. Goforth's opinion in 2004, which was a good procedure. They also told him that they were going to install monitoring wells at the rest of the facilities in 2005 and 6, which did not occur. In fact, some of the wells at some of the DEC facilities were not installed in 2008. And --

Q They were -- they were --

A -- not only that, but the wells that were installed near the residences showed contamination, and DEC did nothing about it.

Q Okay. The wells that you say should have been installed in 2006 were ultimately installed, were they not?

A They were installed as late as 2008, yes.

Q Okay.

A And then they didn't follow the USWAG action plan when they had data. The USWAG action plan was very specific about what to do. It said if you have groundwater exceedances, you're supposed to work with the State regulatory program to come up with a plan and do corrective action. And they, in 2004, in this very email that you -- said we want to be proactive about this issue, and that's not what happened.

Q Yeah. We'll get -- we'll get there, Mr. Hart. Don't worry.

A Well, I already got there.

Q You'll have your opportunity to wax eloquent and all that, but let me -- let me circle back for a moment. And we were talking about the various responsibilities of the DEQ involving coal ash storage and NPDES permits and things of that nature, and that's, of course, in North Carolina, correct?

A That's correct.

Q And the equivalent agency for South Carolina is the South Carolina Department of Health and Environmental Control, correct?

A That's correct.

Q Which is called DHEC, right? Is that what you call it?
A Yes. That's correct.
Q Now, Mr. Hart, you are a, I think, a hydrogeologist by training, correct?
A By education and training and experience, yes.
Q You're not a utility engineer, correct?
A No, I am not.
Q And, in fact, you're not an engineer at all, correct?
A That's correct.
Q And you've never designed a coal ash basin or a power plant associated with a coal ash basin, have you?
A No.
Q And you've never operated a coal ash basin or its associated power plant, have you?
A No.
Q And you are aware, are you not, Mr. Hart, that each of the coal ash basins for which the Company is seeking cost recovery in this proceeding was unlined when it was constructed, correct?
A That's my understanding, yes.
Q And if you would, Mr. Hart, go to your deposition which we marked for purposes of this

proceeding as Cross Examination Exhibit 1, and particularly to page 6 of that deposition.
A Okay.
Q And I asked you at line 16 of page 6 about testimony received in the -- in Duke Energy Carolinas last rate case from the Attorney General witness Dan Wittliff. Do you see that?
A Yes, I do.
Q And you indicated that you, in fact, had not reviewed the testimony of Mr. Wittliff, correct?
A That is correct.
Q And if you go on to page 7 of the deposition, Mr. Hart, I asked you if you were aware that Mr. Wittliff was asked by the then Chair of the Utilities Commission about whether it was his view that the Utility that used unlined ponds, if that Utility was imprudent when it first sluiced coal ash to the impoundments that were unlined. Do you see that?
A Yes.
Q And you -- after a lot of back and forth with Ms. Townsend, I think if you flip over to page 8 of your deposition --
A Okay.
Q -- and I asked you on line 5 if you would

accept, subject to check, that the Chairman of the Commission did ask that question of Mr. Wittliff. Do you see that?

A Yes.

Q And that Mr. Wittliff responded, this is line 12, "...no, the law allowed them to do it and the law continued to allow them to do it, even though there was" -- a -- "concern." Do you see that?

A Yeah. Do you have the actual testimony that I could review? I believe that is something that Mr. Marzo asked for yesterday, the actual testimony, rather than just a subject to check?

Q Well, we can get it for you if you'd like, but that really wasn't the purpose of my question. I'm not -- let me ask you this, did you check after the deposition whether or not Chairman Finley at the time asked the question and Mr. Wittliff answered it in that way?

A I did not.

Q Okay. And then I asked you, Mr. Hart, at line 17 if you agreed or disagreed with Mr. Wittliff, correct?

A Yes, subject to check, that's exactly what he said, which I don't have it in front of me and never have been shown.

Q And, actually, your answer to that question, Mr. Hart, was that you hadn't formulated an opinion about that, correct?
A That's correct.
Q And I asked you if there was a reason you hadn't formulated an opinion about that, correct?
A That's correct.
Q And on line 22 you said "It wasn't part of my scope of work," correct?
A Correct. What I looked at was when DEC was aware of groundwater contamination, violation of the 2L standards and the 2L rules, what actions did it take, and when there was -- you know, after they first determined that there was contamination associated with the ash basins.
Q And that's essentially what you said. Following "my scope of work," you said, "I looked at groundwater contamination associated with the basins," correct?
A Correct, yes, and DEC's response to the groundwater contamination.
Q So you still today have no opinion one way or the other or agreement one way or the other with whatever Mr. Wittliff said in the last proceeding, correct?

A Again, I'm not sure what Mr. Wittliff said in the last proceeding.

Q Now, when you -- if I'm looking at -- at your -- well, I'm looking at your deposition testimony, lines 22, 23 on page 8, where you say that your scope of work was really associated with groundwater contamination associated with the basins. What, Mr. Hart, do you mean by "contamination"?

A Well, contamination typically is something above background for a naturally occurring substance, or in any detectable quantity if it's a manmade substance.

Q Is that what --

A And so we also compare that to the standards as well. So you can have contamination that's not above the standard. You can have contamination that's below the standard.

Q Well, I guess my question to you, Mr. Hart, is what do you mean by "contamination" when you said that your scope of work was to look at groundwater contamination associated with the basins?

A Well, I mean, I think I answered that. It's -- contamination is something in groundwater that's either above background concentration, or if it's a manmade substance something that's there in a detectable concentration. Now, that's contamination. It could be above or below the standard in some cases. And, of course, in coal ash basins, you know, there is a compliance boundary, too, but there's still contamination even if it's within, for example, compliance.

Q And so, I mean, if you take it to the extreme, Mr. Hart, you would say one molecule above the standard, whatever the standard is, is "contamination"?

A Well, I don't know that you could detect one molecule, so it's got to be detectable.

Q Well, if you could detect one molecule, one molecule above the standard would, under your definition, be contamination, correct?

A That would be -- yes, but, again, it's compared to the standard. So in some cases contamination is not a concern if it's below the standard. It would be a concern if it's above the standard.

Q Okay. But it's contamination, nonetheless, the way you have defined contamination, even if it's below the standard, if it wasn't supposed to be there to begin with, correct?

A The way I've defined it, yes.

Q So you're not -- you're not defining contamination for purposes of your testimony the way --

the way that EPA would define, for example, environmental damage or environmental harm, correct?

A I don't know what their definitions are. If you could show me something, I'd be, you know, glad to look at what their definition is.

Q Well, do you have available to you Ms. Marcia Williams' testimony?

A Yes. I have it.

Q If you would turn with me, Mr. Hart, to page 80 of her testimony.

A Okay.

Q And specifically to Footnote 104. Do you see that?

A Okay.

Q And in Footnote 104, Ms. Williams says, "Further, the word 'contamination' in Mr. Hart's statement is also not precise or particularly useful. There is an important distinction between groundwater contamination and groundwater harm. Contamination is any level above background." That's how you're using the word contamination for purposes of your testimony, correct?

A Yes, but, you know, I compare it to the standard, yes.

Q Understood. And Ms. Williams goes on to say "This could include low levels of nitrates in groundwater below farm properties as a result of fertilizer use," correct?

A It could. I mean, the word "contamination" now would only be a concern if it was above 10 milligrams per liter, which is the standard.

Q But assuming it was above 10 milligrams per liter, you would call that contamination, correct?

A Yes. I would -- yes, contamination above the standard at a potential -- at a level of concern.

Q Okay. And Ms. Williams goes on to say "Environmental harm is levels of contamination above some type of health-based level that results in exposures to receptors that come into contact with that groundwater, whether from drinking water use or another beneficial use." Do you see that?

A Yes. I think it shows Ms. Williams' unfamiliarity with the North Carolina groundwater standards and rules. It says nothing about whether it has to have exposures to receptors. It says that if you exceed the standard, you are required to assess the cause and significance, eliminate the source, and then develop a corrective action plan. There is no statement in the

North Carolina 2L rules or standards about whether the groundwater has to come in contact with a receptor that's drinking water or some other receptor. It's not receptor-based, the groundwater standards in North Carolina.

Q Understood, Mr. Hart. I'm really just trying to establish what you mean by contamination, and that what you mean by contamination is different than what the EPA would call environmental harm, correct?

A Well, I mean, I think Ms. Williams even says contamination is any level above background. That's what -- that's how she defines it. And then she goes on to explain environmental harm. Now, she -- that's her opinion. There's no reference to this is EPA's opinion. This is her opinion. So my point is that the 2L rules don't talk about it. They talk about protecting groundwater as a resource for all citizens of the state. They don't talk about whether it has to have a receptor, because all groundwater may become a future use of groundwater and then impact a receptor.

Q Mr. Hart, if you would look at page 8 of your testimony in this proceeding, and particularly lines 5 through 7.

A My testimony?

Q Not the deposition; your -- your prefiled testimony.
A Okay. What page? I'm sorry.
Q Page 8 --
A Okay.
Q -- lines 5 through 7 --
A All right.
Q -- where you indicate that one of the results of your investigation is the conclusion that the utility industry, including DEC, "knew about the potential for contamination of groundwater from coal ash basins as early as the 1980s." Is that correct?
A Yes. That's correct. That's what it says.
Q And you're using -- your meaning of the word contamination in that testimony is the same as what you just gave us a few minutes ago, that is, some level above background, correct?
A Yes. It knew, and it shouldn't have been surprised when it put in monitoring wells and found contamination in many cases above the 2L standard. It knew that this was certainly a possibility for unlined coal ash basins, yes.
Q And, Mr. Hart, groundwater monitoring occurred at DEC -- DEC coal ash basin sites as early as 1978;

isn't that correct?

A I don't know if it's '78. I know -- the earliest I have seen is at the Allen plant, and it may have been '78 or '79, reported in, I believe, '84. But maybe, yes.

Q So if you actually -- if you look at the -- I guess it's Joint Exhibit 9 --

A Okay. I have that.

Q -- and that is the report of -- Duke Energy's report of the Allen plant monitoring program, correct?

A Yes. The investigation of the coal ash basin groundwater at the Allen plant as part of a broader EPA study. Yes.

Q And the page -- I guess they're actually -- since this was part of the appellate record from the -- from the last case, which I guess is still at the Supreme Court right now, but there's a -- there's a page number at the top of each page.

A I don't have -- I don't have that page number, but I can --

Q Oh. Well, why don't you go to page 14 of the report, then.

A Okay. I'm sorry. Yes.

Q It's also called Doc. Ex. 4909 for anybody that happens to have that -- happens to have the appellate record. And right at the top of the page, the report describes the monitoring program at Allen, correct?

A Correct.

Q And it says "A monitoring program more extensive than that required by RCRA," R-C-R-A, "has been in progress at the Allen Steam Station since 1978," correct?

A Correct.

Q And the investigations at the Allen plant and the results of those investigations were published in this report, Joint Exhibit 9, correct?

A Yes, they were. Well, a summary of them.

Q Well, they weren't keeping them under a bushel somewhere, Mr. Hart, were they? They were published.

A Well, this -- the actual data isn't published, is my point, that we have summaries of the data.

Q Okay. Was the actual data hidden somewhere?

A I don't know. It wasn't provided to anyone that I have seen the actual data to be able to verify tables and see if other, you know, constituents, for example, were analyzed for it.

Q Okay.

A So they have provided a summary of the data.

Whether that's the complete summary of the data or not, I don't know.

Q And the Allen plant also underwent additional investigation in the mid-1980s by Arthur D. Little under contract with US EPA, correct?

A Yes, yes.

Q And that data is in that report, which I think is Joint Exhibit 10, correct?

A Yes. I have not looked at that report.

Q And that report is well over 1,000 pages long, and it includes all the data that was collected in connection with the Arthur D. Little study, correct?

A I don't know that. I'm not saying it's not. I just don't have -- I haven't looked at that report.

Q And the Allen plant underwent additional investigation by a contractor for the Electric Power Research Institute, or EPRI, did it not?

A I don't know. I don't know that I have that.

Q If you would look, Mr. Hart, at Joint Exhibit 12.

A Okay.

Q And go to page 1 of that report and on to page 2. And if you have the Doc. Ex. numbers, that would be Doc. Ex. 9440 to 9441.

A I don't have that report. I'm trying to find it. I only downloaded the DEC exhibits. I wasn't aware we had -- about these joint exhibits, but --
Q So you don't have the Joint Exhibit 12?
A No, I do not.
Q Well, let me just read it to you, and we'll do this, again, subject to check, and you can check --
A Okay.
Q -- later and see --
A I could probably pull it up from like the data site, if I need to.
Q Okay. Well, I don't -- I don't know where you would find it on the data site, but the report is a report -- and it's also from the last case, Wells Public Staff Cross Examination Exhibit Number 8, if you happen to have that.
A Okay. It's for the River (sic) plant. I mean, its title is Riverbend Plant.
Q Yes. It's the Riverbend evaluation.
A Right.
Q So it's titled "Evaluation of the Effects of Ash Disposal at the Riverbend Plant of Duke Power Company on Groundwater and Surface Water Quality," prepared for Duke Power Company. There's not a date on the first

page, but it's the late '80s, as I recall.
A So it's a Wells exhibit? Let me go find it.
Q Well, let me do this, Mr. Hart --
A Which one is it? I'm sorry. I think I can find it. I just --
Q Well, I don't -- I don't think it's necessary. Again, you can check me on just what I read, but it is or was also Wells Public Staff Cross Examination Exhibit Number 8 in the prior case. And I'm reading from the bottom of page 1, which is also Doc. Ex. --
A All right. I found it. I found it. I'm sorry.
Q All right.
A I did find it.
Q Doc. Ex. 9440. "Intensive studies on the effect of ash disposal have been conducted at the Allen Plant, which is also located in Gaston County about 12 miles south of the Riverbend Plant." And they indicate that Duke Power conducted a study, correct? That's the 1984 report, Joint Exhibit 9.
A Yes.
Q And they indicate Arthur D. Little conducted a study under contract with the Environmental Protection Agency, and that's Joint Exhibit 10, correct?

A Correct.
Q And they indicate that Tetra Tech, under contract with the Electric Power Research Institute, also conducted studies in July of 1985, correct?
A I'm sorry. What page are you? I don't have this Doc. on my copy.
Q I'm at --
A I have the report.
Q I'm looking at page 1 and 2 of the report.
A Okay. I'm sorry.
Q If you're looking at it on a PDF, it might -- it's probably PDF page 9 and 10.
A Okay. Yes. I'm sorry. I'm there.
Q Okay. So those -- those three studies were conducted at the Allen plant in the mid-1980s, correct?
A Correct. And for the groundwater contamination associated with the basin. In fact, that's documented in EPA's 1988 report. In fact, it says that manganese concentrations were high and unlikely to be steady state, and they expected further migration of manganese in groundwater at the Allen plant. And this, of course, is before the time when there was a compliance boundary, so any violation of the standard would be a violation of the standard.

Q Okay. Mr. Hart, if you look back at page 1 of the Riverbend report --

A Okay.

Q -- Joint Exhibit 12.

A Yes.

Q The report itself states that the "studies show that groundwater quality has not been significantly degraded by seepage from the Allen plant ash ponds," does it not?

A It says that, but that's -- that's incorrect. What the conclusion of that report was, was that the mass discharge from the Allen plant into surface water was much smaller than the flow of the adjacent river. So, yes, that's obvious, right? So the river is going to have a flow rate in thousands of cubic feet per second, and a groundwater flow might be in the range of a tenth of a cubic foot per second by a flux into -- into the river. But it didn't mean that there wasn't a problem with the groundwater. What they concluded was the groundwater that was impacted at the Allen plant wasn't having an effect upon the surface water, and that was their barometer for determining whether there was an impact, not whether the groundwater was contaminated. In fact, the data showed that the groundwater was contaminated at the ash basin at the Allen plant.

Q All right. So when they say "These studies show that groundwater quality has not been significantly degraded by seepage from the Allen plant ash ponds," are they wrong?

A Well, I think it's how you interpret the word "significantly."

Q Ahh.

A They had contamination above the 2L standards in some cases.

Q Okay. And so this is -- we're going back to, really, the -- the difference between a definition of contamination that's something above background versus something that would cause environmental harm, correct?

A Well, no. This is contamination that was above the 2L standards, but what their conclusion was is that it was attenuated to a certain extent and then it was further diluted in the river, the conclusion being that dilution is the solution to pollution, from their standpoint.

Q And that's why it's "not significantly degraded," correct?

A I don't know what they mean by that. It was above the 2L standards for several constituents. And as

I mentioned, in EPA's 1988 report they identified that manganese, I believe, was up to 120,000 parts per billion versus the standard of 50. And they say that they believe that if it's not in steady state and it will continue to mobilize because the exchange capacity or the attenuation capacity of the soil will not be sufficient to attenuate that kind of contamination.

Q Yeah. We'll get to the 1988 report, Mr. -- Mr. Hart.

A You have to dig -- you have to go deep in the 1988 report. You can't just read the conclusions.

Q Mr. Hart, the -- the -- we were talking about the groundwater monitoring program at the Allen plant that began as early as 1978, correct?

A Correct.

Q And further groundwater monitoring took place in the mid-to-late 1980s at Marshall and Belews Creek, those power plants, correct?

A I'm looking. Yes.

Q And this was in connection with NPDES permits issued in connection with the operation of those plants, Marshall and Belews Creek, correct?

A Well, I believe in both of them it was 1989.

Q Okay. So late 1980s, not mid 1980s, correct?

A Right. And then the monitoring that was done was for a landfill, but it was in some cases the groundwater wells were put adjacent or very near the coal ash plant. They weren't specifically, as I understand it, intended to be monitoring points for the coal ash basins.

Q But you actually used the data from -- from those wells in connection with your evaluation of groundwater -- groundwater "contamination," your definition of contamination, at those plants from the ash basins, correct?

A Well, sure. If you're going to put a well next to the ash basin, even though it was intended to monitor landfill, it doesn't mean you ignore the data because it was put next to the ash basin.

Q So my question to you is, there was groundwater monitoring in the mid-to-late 1980s at both Marshall and Belews Creek as part of the -- of an NPDES permit program, correct?

A Correct. Late -- 1989 is when I show the earliest groundwater monitoring.

Q Okay. And there was further groundwater monitoring at Dan River and the W.S. Lee plants beginning in the early 1990s as part of an NPDES permit program with respect to those plants, correct?

A Correct, 1993, yes, at both of them.

Q And that monitoring program was, in fact, with respect to the ash basins at those plants, correct?

A That's correct. That's my understanding, yes.

Q And then we talked already about the groundwater monitoring that took place as part of the USWAG voluntary monitoring program, correct?

A That's correct. I mean, we touched on it briefly, yes.

Q And that -- that involved essentially all of the Duke Energy Carolinas plants, starting with Allen in around 2004 and going forward with a number of the other plants until the late 2000s, correct?

A That's correct.

Q And Mr. -- Mr. Hart, do you have any information that suggests to you that these monitoring wells, all of them that we've just been talking about, apart from the Allen early time period, were all done in connection with either the USWAG study or NPDES permits, that the location and number of wells, the depths of the wells, the sampling frequency and the sampling parameters were not established in conjunction with whichever environmental regulatory agency, DEQ or DHEC, was in charge of those programs?

A Well, I think to the extent that they were associated with a permit, for example, at Dan River or W.S. Lee, I do believe that they were most likely installed in conjunction with the DEQ's input and the parameters were agreed upon. Now, with regard to the other facility where it was part of USWAG, other than the Allen plant, I don't see any indication that they were -- those wells were installed in conjunction with some input from DEQ. In fact, DEQ, when the data was submitted, had a number of comments about the well location. Some of them, they said, were not appropriate for background determination, things like that. And they also said, at that time, we need to increase the parameter list to come up with a larger set of parameters for things like boron and vanadium that weren't analyzed for in USWAG.

Q Well, they had comments about the well placement for the Allen plant, too, didn't they, when they -- in the latter part of the 2000s?

A They -- I don't know. I'd have to -- I'd have to look. But I see no indication that they installed those wells as part of USWAG, other than at the Allen plant, as part of some discussions with DEQ. But if you have some, you know, documentation to that effect, I'd be glad to look at it.

Q Well, let's -- let's move just slightly, Mr. Hart. You mentioned that at least with respect to the permitted wells that are part of an NPDES permit program, the relevant environmental agency would have had some input into and direction to the permitee, in this case Duke Energy Carolinas, about well placement and parameters -- frequency of sampling and the parameters of the sampling, correct?

A Typically, yes, although I haven't seen any documentation. But, yes, typically that would be the case.

Q And these NPDES permits are regularly renewed, correct?

A Yes. They are usually on a renewal cycle. That's correct.

Q And in each of the renewal processes, the relevant environmental regulator can adjust its requirements relating to sampling frequency and sampling parameters, and often does, correct?

A In some cases, yes, they can. Uh-huh, yes.

Q And Mr. Hart, with all of this monitoring going on over the time frame that stretches back to 1989, DEC reported to the DEQ the sampling results every single time, as required by its permits, correct?

A I don't know that. We did FOIA requests for these facilities, but in most cases they did not have the data or weren't able to find the actual submittal, so I don't know that for a fact.

Q Look, if you would, Mr. Hart, at DEC Exhibit 20.

A Okay.

MR. MEHTA: Chair Mitchell, I would ask that this document, DEC Exhibit 20, be marked for identification as Hart DEC Cross Examination Exhibit 3.

CHAIR MITCHELL: All right, Mr. Mehta. Just keeping with the convention we've established for your previous exhibits, we will mark this document as DEC Hart Cross Examination Exhibit 3.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, DEC Hart Cross Examination Number 3 was marked for identification.)

Q And Mr. Hart, what this document is, is what's commonly referred to in the last proceeding and presumably will be referred to in this proceeding, as the Sutton Settlement. Do you understand that?

A Yes, but -- yeah. So, yes, if that's what you want to call it, that's fine.

Q Well, you can -- you can check me in the voluminous record from the last proceeding, but we called it the Sutton Settlement.

A Totally fine. I understand.

Q And if you look at the bottom of page 2, there's a whereas clause that says, "Whereas, the National Pollutant Discharge Elimination System (NPDES) permits associated with the Duke Energy sites contain requirements for Duke Energy to monitor groundwater at the Duke Energy sites and report the results to DEQ," correct?

A Yes. It's not really talking about what time period. A lot of them didn't have groundwater monitoring requirements in them until barely like post-Dan River, I would say. This is 2015, so I think it was mostly post-Dan River. So the only one, I think, that proceeded this, and I could be wrong, is Dan River itself.

Q Well --

A And it had something in it -- a requirement in the NPDES permit that required groundwater monitoring.

Q Okay. So Dan River clearly had that because they had the permit requirements from the early 1990s, correct?

A Correct.

Q And Marshall and Belews Creek clearly had that because they were -- there were wells installed as part of an NPDES permit program in, I think you said, 1989, correct?

A Well, that wasn't for the NPDES permit. Those were for landfill, solid waste permits --

Q Well, but then --

A -- at those two facilities. Those weren't NPDES permits --

Q In any event --

A -- where they are required.

Q In any event, Mr. Hart, do you have any information whatsoever that suggests to you that Duke Energy Carolinas did not provide to the DEQ every single result from its groundwater monitoring programs at any of its plants to the DEQ?

A Well, for example, I haven't seen data from 1984 or 1978 or '79 at the Allen plant that it was submitted to DEQ. Now, to the extent it was part of some NPDES permit, I don't have anything to disagree with that, other than to say that for the most part, other than Dan River, the facilities didn't have groundwater monitoring requirements in them until, I believe, 2014 or

'15 after Dan River --

Q In any event --

A -- after the spill.

Q But Mr. -- Mr. Hart, if you'd just look at the next page of the Settlement Agreement, the top of page 3, the whereas clause says that Duke Energy has complied with its groundwater monitoring and reporting requirements with respect to the Duke Energy sites, correct?

A That's what it says.

Q Okay.

A But what I'm getting at is -- what you're trying to imply, I think, is that there's this long history from 1989 and 1993, all the way to 2015, of Duke submitting groundwater data required under its NPDES permits. That's not correct. They only had groundwater monitoring requirements for their coal ash basins for NPDES permits starting, I believe, in 2014 and '15 at some facilities, but what -- so there's not this voluminous data that DEQ had in 2015 at these facilities. They had some data from the USWAG, but they didn't have a bunch of data from the NPDES permits.

Q Mr. Hart, do you have any information that suggests to you that Duke Energy Carolinas did not submit to the DEQ all of the groundwater monitoring information generated as a result of this USWAG voluntary groundwater monitoring program?

A I don't have any information to that effect, but I haven't looked at -- well, again, we did FOIA requests at DEQ for these facilities. There are some data submittals, but I don't know if they're every single one, but there are some that were submitted to DEQ, yes.

Q Well, Mr. Hart, let's talk, then, about what you did or what you looked at in conjunction with your investigation of this matter. And I think the -- if you look at pages 6 and 7 of your prefiled testimony, you outline what you looked at, right?

A Yes, I did.

Q So you reviewed the coal ash related testimony in this case, correct?

A I'm not sure I understand what you mean.

Q Let me -- maybe that was a bad question. I'll try it again. I'm looking at lines 6 and 7 on page 6.

A Right. Yes. I --

Q And you say --

A Go ahead.

Q You say there, "I reviewed the parts of DEC's 2019 rate case application and testimony relating to coal ash," right?

A Correct.

Q And the next --

A To the extent that I knew it was coal ash related. Now, there's a lot of documents in there and not every one is listed as coal ash, but if they had some indication of coal ash or, for example, Ms. Bednarcik's testimony, I did review it.

Q Okay. And you also indicated that you were provided access to the Merrill data site, which is a document portal for documents produced in connection with this case, correct?

A Well, I had access to it and I did some queries. Now, that's a very -- it is not a -- it's a pretty user friendly document portal, but I did do some queries and was able to get some documents.

Q And you also indicate in the third bullet that you were provided access to the Concilio/Relativity online database and performed queries and reviewed various documents in -- in that portal, which as I understand it, houses millions of documents that have been produced by Duke Energy over the course of years in connection with any number of legal proceedings, correct?

A That's my understanding, yes, but, again, no way to review every document on there. I did some queries, to the extent I could, and -- and was able to find some documents.

Q So I guess, Mr. Hart, you would actually be the first to admit that you did not review every single document in that database to assess its impact on the question of whether Duke Energy Carolinas was, you know, proactive enough with the -- with its environmental regulators, did you?

A I don't know that anyone could review every single document in that database in the time frame of -- of which I did my work.

Q I --

A I would think it humanly impossible.

Q Understood, and I would agree with you. You did not actually talk to anybody at DEQ to investigate its view of whether DEC was being proactive enough, did you?

A No. I think, as I mentioned in the deposition, we did try to reach out to some of the folks at DEQ, but because of the ongoing litigation between DEQ and DEC, they were very hesitant either to provide documents or discuss items.

Q Well, your client in this proceeding is the

Attorney General's Office, correct?

A Correct.

Q And the Attorney General's Office is an agency of the State of North Carolina, correct?

A Correct.

Q And the DEQ is an agency of the State of North Carolina, correct?

A That's correct.

Q And when the DEQ needs legal advice or representation, it looks to the Attorney General's Office to provide it, doesn't it?

A I believe so, yes. Sometimes it seeks outside counsel as well.

Q So, Mr. Hart, I'm curious. If you wanted to find out from the DEQ what -- its view of the proactive nature of DEC's actions regarding groundwater monitoring, why didn't you just ask your client, the Attorney General's Office, to get in contact with the DEQ and set up interviews with present or former DEQ officials who could answer your questions?

A Well, I think the documents speak for themselves for the most part.

Q So you don't think --

A It's very clear that DEC submitted the USWAG data to DEQ without any explanation. They implied that the data was consistent with background, which it clearly was not. And, you know, it wasn't until DEQ started looking at the data in 2009 and '10 that they said, look, we think there's -- you need to provide us more information here. Those are -- those are written in the -- in the letters from DEQ to DEC. You've been providing this data. We don't know whether wells are -- we see 2L standard violations. We need more information.

Q So, Mr. Hart, you don't think it's necessary to obtain the DEQ's views directly from somebody at DEQ in order to assure yourself that your investigation was fair and that the conclusions you reached were supported by a complete review of the evidence? Is that what I'm hearing?

A No. I think I did do a complete review of the evidence, you know, and my experience. I mean, I know how groundwater has been addressed and how people deal with groundwater in North Carolina. I've been dealing with it for 30 years, including the 2L regulations. I don't have to talk to a regulator to tell me whether DEC -- what their opinion was of DEC. The -- the rules are very clear as to how you address them. And, in fact, the USWAG policy was -- or the action plan was very clear, and this is why they went to DEQ and EPA and said, if we have groundwater standard exceedances, then we're going to address them and come up with an action plan to deal with them. We're going to come up with a corrective action plan to deal with them, and that didn't happen.

Q Turn, if you would, Mr. Hart, to DEC Exhibit 40.

CHAIR MITCHELL: All right, Mr. Mehta. Before you begin this next line, we're going to take a morning break. We're going to go off the record now. We'll go back on at five after 11:00. During this break I'd ask that you all please work out order of witnesses, in light of our discussion on the CIGFUR motion at the beginning of the hearing this morning. All right. We'll be back on at 11:05. Please turn off your cameras and your microphones.

(Recess taken from 10:47 a.m. to 11:14 a.m.)

CHAIR MITCHELL: All right. Let’s go back on the record, please.

THE WITNESS: Can you all hear me?

CHAIR MITCHELL: All right. I’d like to address the pending Motion to Strike raised first by counsel for CIGFUR III. I am going to deny the motion and allow the testimony of Mr. Floyd to stand. I’m going to deny the Request for Leave to file rebuttal that counsel for CIGFUR III made as well. I am going to allow CIGFUR to put up its witness following the presentation of the -- I believe it’s the McLawhorn/Floyd Panel.

And with that, any additional matters for me to consider before we get back into the cross examination of AGO witness Hart?

MR. PAGE:: Madam Chair, this is -- go ahead, Camal.

MR. ROBINSON: Yeah. Sure. Hi, Chair Mitchell. I just wanted to at least report back. So we did have a call with some of the parties on break, not every party was on the phone, and through the discussion, just to notify you, the parties have generally agreed that Mr. Phillips could be the last cross examination -- could be the last attorney -- excuse me -- the last witness to testify after the Public Staff. So just wanted to flag that for you, and that we defer to Ms. Cress and Ms. Downey and Mr. Neal for anything further.

CHAIR MITCHELL: All right.

MS. DOWNEY: Chair Mitchell?

CHAIR MITCHELL: I believe that’s Ms. Downey.

MS. DOWNEY: Yes. Yes, Chair Mitchell. In light of that, the Public Staff would like to reserve cross time. We had not done so up to this point.

CHAIR MITCHELL: You -- reserve cross time for CIGFUR witness Phillips?

MS. DOWNEY: Yes, Chair Mitchell.

CHAIR MITCHELL: Okay. Understood.

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

CHAIR MITCHELL: You may proceed, Mr. Neal.

MR. NEAL: NC Justice Center, et al. would also ask to reserve cross time following additional testimony from Mr. Phillips.

MS. CRESS: And Chair Mitchell, this is Christina Cress with CIGFUR. That’s consistent with what the parties discussed on the call, and CIGFUR is in agreement -- not in agreement, but, rather, we consent.

CHAIR MITCHELL: Okay. So Mr. Phillips will be presented following, just for purposes of the record and so that we’re clear here, following the presentation of the Public Staff’s witnesses. By my notes, that indicate -- the final Public Staff witness is Boswell, so following Boswell. And I have that both the Public Staff and North Carolina Justice Center, et al. have reserved cross examination for the witness.

MR. PAGE: Chair Mitchell?

CHAIR MITCHELL: Any other parties to --

MR. PAGE: Chair Mitchell, this is Bob Page.

CHAIR MITCHELL: Mr. Page, I'll get to you in one second. Let's wrap up on this CIFGUR witness Phillips issue. Any additional parties reserving cross examination for the witness?

(No response.)

CHAIR MITCHELL: All right. Hearing none, Mr. Page, you may proceed.

MR. PAGE: Thank you, Chair Mitchell. I wanted to advise you of a situation and perhaps follow that up with a motion. My witness, Mr. O'Donnell, has a conflict with appearance at the Maryland Commission, and he's been juggling these two events for the last two weeks. He's already put them off twice in anticipation of getting on, and it just hasn't worked that way. I think that the book that the rabbi wrote about bad things happening to good people pretty well explains where we are. But if I can get him on, and I don't know how much longer Mr. Mehta has with the Attorney General's witness, or how many questions the Commission may have, if I can get Mr. O'Donnell on this morning before the lunch recess, then he's able to continue this afternoon until he's finished, but if I can't do that, then it will be tomorrow afternoon before he's available again. So in that circumstance, I would move to take him out of the rotation following Mr. Hart and put him back in sometime during or after the Public Staff's testimony.

CHAIR MITCHELL: All right. Mr. Page, is this a matter that was discussed with the parties during the break?

MR. PAGE: I was not in on that conversation. Nobody called me.

CHAIR MITCHELL: All right. Does any party object to -- counsel for any party object to reorganizing or rearranging order of the witnesses at this point to accommodate Mr. Page's request?

(No response.)

MR. PAGE: That would mean, in essence, that we would go from Mr. Hart down to Mr. Ryan on the witness list.

CHAIR MITCHELL: Any objection from any party, counsel for any party?

(No response.)

CHAIR MITCHELL: All right. Hearing none, Mr. Page, I'm going to allow you to call your witness tomorrow afternoon whenever he may be available.

MR. PAGE: Thank you, Madam Chair, and I will advise you when I know that he will be.

CHAIR MITCHELL: All right. Mr. Mehta --

MR. JENKINS: Madam Chair?

CHAIR MITCHELL: -- we'll proceed with you.

MR. JENKINS: Madam Chair, Alan Jenkins.

CHAIR MITCHELL: Mr. Jenkins?

MR. JENKINS: May I proceed?

CHAIR MITCHELL: You may.

MR. JENKINS: Thank you. Commercial Group was also not called on that matter, and is the intent to move the two Staff witnesses Floyd -- the Floyd Panel further down the list, because I believe Duke still has a right to rebut -- file rebuttal testimony of that. And it seems -- it seems it would be more appropriate to have them go later than earlier.

CHAIR MITCHELL: Mr. Jenkins, I do not understand your question. Would you please ask your question again?

MR. JENKINS: Sure. Right now the Floyd Panel for Staff is fairly early in the Staff order, and I believe Duke has the right to file rebuttal testimony to the Floyd testimony that was just filed and that the Motion to Strike was not granted. So it seems more appropriate to have the Floyd Panel move further down at least among Staff and perhaps later on in the proceedings, just have rate design witnesses, rather than having them so far in advance and in advance of Duke's rebuttal testimony.

CHAIR MITCHELL: All right. Mr. Jenkins, at this point in time the decision has been made to allow CIGFUR witness Phillips to be presented for examination purposes following the final Public Staff witness, so that's where things stand procedurally at this point in time. All right. Anything further?

(No response.)

CHAIR MITCHELL: All right. Mr. Mehta, we are with you and Mr. Hart. Please proceed.

MR. MEHTA: Thank you, Chair Mitchell. And Mr. Hart, your video just went out. There we are.

THE WITNESS: Sorry. Hit the wrong button.

MR. MEHTA: Yeah. I do that all the time. Sign of advancing age, I'm afraid, Mr. Hart.

THE WITNESS: If I could, I just want to correct something I said earlier on the NPDES permits and groundwater monitoring. The NPDES permits -- I went back and looked at some of the permits -- started requiring groundwater monitoring at some facilities around the 2011 to 2013 time period after the USWAG data had been submitted, not after the Dan River spill. So that's --

my apologies. I just wanted to correct that on record to be accurate.

MR. MEHTA: Okay. Thank you, Mr. Hart.

Q And actually on that subject, if you would take a look at your deposition which we marked as Exhibit 1, Cross Exhibit 1.

A My deposition. Okay. Yes.

Q And page 79 of your deposition.

A Okay.

Q And the subject matter on this page is the submission of data by Duke Energy Carolinas to the DEQ, correct?

A Yes. Generally, yes.

Q Okay. And you indicate at line 15 -- starting at line 15 that the earliest date of submittals that you've seen or you had seen was from the 2009 time frame, correct?

A Yes. That's correct.

Q And on line 17 you said "I tried to get more historical data," correct?

A Correct.

Q But you could not locate more historical data, correct?

A Yes. We did a FOIA request and did, in fact, get the Attorney General’s Office involved, and DEQ sent us what was in their electronic files. This was during the COVID -- well, we’re still ongoing, but the beginnings of the COVID issues, and so they had no one in the office that was willing to go to the office and look for the files.

Q And you further indicate that while you tried to locate it, you couldn’t, and you "don’t have any evidence that they did,” meaning that Duke Energy Carolinas did submit such data; is that correct? That’s lines 19 and 20.

A Right. So not saying that they didn’t submit it, but I don’t have evidence that they did.

Q And then I asked you on line 21 “Do you have any evidence that they did not,” and your answer on line 22 was “No,” correct?

A Correct. Yes.

Q And I asked you at line 23 “Do you have any reason to believe that they did not,” and your answer at line 25 and carrying on to the next page was “I don’t have any reason to believe that they did not send in the data, no.” Is that correct?

A That’s correct, yes.

Q Now, Mr. Hart, look, if you would, at DEC

Exhibit 40.

A Okay.

MR. MEHTA: And Chair Mitchell, I'd like to go ahead and mark this document as -- let me get my sequence straight. I guess this would be DEC Hart Cross Examination Exhibit 4.

CHAIR MITCHELL: All right. The document will be so marked.

(Whereupon, DEC Hart Cross Examination Exhibit Number 4 was marked for identification.)

Q And Mr. Hart, this is a deposition of Coleen Sullins taken in what we've come to call the Sutton OAH proceeding, correct?

A It says Duke Energy Progress vs. North Carolina Department of Environment and Natural Resources, Division of Water Resources, is with the -- well, in the Office of Administrative Hearings.

Q Okay. And it's an OAH, Office of Administrative Hearings, proceeding, and would you take, subject to check, that it involves the OAH's or -- excuse me -- DEQ's imposition of a fairly sizable monetary penalty in connection with the operation of the Sutton plant?

A That’s my understanding, yes.
Q Thank you. And Mr. Hart, if you would look at pages 9 and 10 of the deposition, Ms. Sullins notes there that while at the time of the deposition she was no longer with DEQ, her last full-time position there was the Director of the Division of Water Quality, correct?
A I’m sorry. What lines are you on?
Q Let’s see. Page 9 -- page 9 at the very bottom of the page she’s asked “What’s your current employment status,” and she -- and the answer is “I’m unemployed,” correct?
A Yes. That’s what she says. Right. Yes.
Q And if you go on to page 10, the question is “What was your last full-time employment?” The answer is “Director of the Division of Water Quality,” correct?
A Yes. That’s what it says. Yes.
Q And line 7, the question is “When did you leave that employment?” The answer is “December of 2011," correct?
A Correct.
Q And Mr. Hart, just to level set us, the questions being posed to Mr. -- to Ms. Sullins, if you go up to probably page -- very early -- page 2, the questions are being posed by Mr. Wheeler, correct?

Excuse me. Page 6, line 3.

A Six, line 3. Yes, by Mr. Wheeler. I see that. Yes.

Q And if you go -- maybe this is what's on page 2. Yes. Appearances for the Respondent, which is the DEQ, Mr. Wheeler is the lawyer for the DEQ, correct?

A Yes. That's my understanding, yes.

Q Okay. And if you go back to page 10 where Ms. Sullins says that her last full-time employment was as Director of the Division of Water Quality, the Division of Water Quality is a division within the DEQ, is it not?

A That's correct.

Q And it is the division at DEQ that is responsible for groundwater and surface water regulation, correct?

A Well, I mean, there are other divisions. Division of Waste Management also is involved in groundwater rules and groundwater conditions, but they are the ones responsible for, for example, the coal ash basins and for rules that are associated with surface water regulation.

Q The Division of Water Quality is or the Division of Solid Waste Management?

A The Division of Water Quality, which is now the

Division of Water Resources.

Q Okay. And the Division of Water Quality is the Division or whatever its name is now, but certainly it's the division responsible for, for example, enforcement of the 2L rules, right?

A Well, it could be. I mean, there certainly are other divisions that also enforce the 2L rules. I mean, you could have a Superfund site or a site under RCRA regulation or inactive hazardous sites that also, if they had a groundwater standards violation, could also issue some sort of Notice of Violation or regulatory requirement with regard to 2L.

Q But the Division of Water Quality is an agency that is involved in the enforcement of the 2L rules, correct?

A That's correct.

Q Now, Mr. Hart, if you look at the very bottom of page 21 of Ms. Sullins' testimony -- are you there?

A Yes, I am.

Q The question posed by the lawyer for the DEQ on line 25 is "Let's focus in on the coal ash issue." And moving on to page 22, the top of page 22, he asks if Ms. Sullins could tell him when the issue of coal ash first sort of came on her radar, correct?

A Correct.
Q And he indicates that he -- what he really wants in lines 5 and 6 is when it came on her radar any time during her tenure at DEQ, correct?
A Yes.
Q And on line 7 she answers that it came on her -- on her radar when she was a permit supervisor over the NPDES permitting programs, correct?
A Correct.
Q And if you look back at page 13 of her deposition, Mr. Hart, she indicates that she became the permit supervisor back in 1992, correct?
A Well, she was dealing with stormwater until 1992 and then -- oh, yeah, supervisor for the NPDES program, yes.
Q So --
A Sometime after 1992, I guess.
Q All right. If you flip back, then, to page 22 -- just tell me when you're there.
A Okay.
Q And on line 10 she says "Coal ash has been an issue that I dealt with for most of my career at the Division of Water Quality," does she not?
A Yes.

Q And if you go forward, Mr. Hart, to page 26, the bottom of page 26 --
A Okay.
Q -- and it's really the question that begins on page 25 and then carries over to -- excuse me -- line 25 and then carries over to page 27, the lawyer for the DEQ asks Ms. Sullins what the first time you -- she remembered groundwater issue coming up after she began her supervisory work over aquifer issues, correct?
A I'm sorry. Where is that? What line?
Q I'm sort of paraphrasing, but just tell if I'm paraphrasing incorrectly. Page 26, line 25, then the question carries over to page 27, lines 1 through 3.
A Okay. Yeah.
Q And just to level set us on the timing, then, Mr. Hart, if you go back to page 15 of her deposition, lines 12 through 19 -- just tell me when you're there --
A Okay. Yeah. I'm there.
Q Ms. Sullins indicates that she first gained supervisory control over aquifer protection when she became the Deputy Director of the Division of Water Quality which was in 2004, correct?
A Correct, yes.
Q And then if you, again, flip forward, Mr. Hart,

to page 27 of Ms. Sullins' deposition --
A Okay.
Q -- lines 4 through 7, after the lawyer for the DEQ asked her when -- the first time she remembers the groundwater issue coming up after she became in a supervisory role was in the wake of the TVA dam collapse, correct?
A Correct.
Q And the TVA dam collapse took place in 2008, if my memory serves. Does that sound right to you?
A Yes. She's saying -- yes, 2008, she's saying is when we -- when we started looking at coal ash more holistically in the state.
Q Okay. And then if you move forward, Mr. Hart, to page 29 of her deposition.
A Okay.
Q Starting at line 2, the lawyer for the DEQ asks Ms. Sullins if it was her understanding that until the Tennessee Valley spill, there had not been any other activity on that subject. Do you see that?
A Yes.
Q And if you just go up a page to page 28, lines 24 and 25, that subject that the lawyer for the DEQ is talking about is groundwater monitoring, correct?

A Yes. About in the previous decade there was discussion about the possibility of groundwater monitoring.

Q And on page 29, in answer to the question if it was Ms. Sullins' understanding that until the TVA spill there had not been any other activity on that subject, groundwater monitoring, Ms. Sullin -- Ms. Sullins answers, line 5, "No. That's not my understanding," correct?

A Right. And then she qualifies it by saying "I don't know the details about the groundwater monitoring."

Q That's correct. But at line 7 she says that discussions had been held between the utility companies and the Aquifer Protection staff about getting wells installed and beginning some initial evaluation, correct?

A Well, she says "I don't know the discussions that had been held," not -- I read that as I don't -- you can read that two ways. One is whether they had been held, or one is she doesn't know whether they had been held, but that's what it says.

Q Well, immediately before that she says "I don't know the details," and then says "I don't know the discussions that had been held."

A Right.

Q That would suggest that there were discussions that had been held of which she does not know the details; isn’t that correct, Mr. Hart?
A Again, I think you could read it both ways. I think you could say I don’t know about any discussions that had been held, or there were discussions and I don’t know the details. She doesn’t say there were discussions, I know there were discussions between utility companies and the aquifer protection staff, but I don’t know the details. That’s not what she said. I think you could read it both ways.
Q Okay. Well, in line 11, she says “Some of that had been done,” correct?
A Yeah. I don’t know what the "some" is. Is that meetings or well installation?
Q Well, in line 14, the lawyer for the DEQ asked Ms. Sullins “So this wasn’t a blank slate when the Tennessee Valley spill happened; is that correct?” Do you see that?
A Correct.
Q And her answer is “Absolutely not.” Do you see that?
A Right. And by that time I would agree. They had data from the USWAG monitoring that had been

submitted, but not really reviewed, until 2009 or ’10, which is within her time of looking at it -- within her time of being division director.

Q And if you go on to page 30 of her deposition, Mr. Hart, you will see at lines 15 -- beginning at line 15, Ms. Sullins says “The power companies, we were constantly in interaction with them because we were issuing permits for them to do a variety of different things.” Do you see that?

A Yes.

Q And she goes on to -- she goes on to say at line 19, “So, you know, they,” meaning power companies, “were sort of always on the radar like a large -- a large permitted entity would be, and a complex permitted entity because it involved multiple divisions trying to figure out how to issue the various permits for which they had responsibility and deal with the various issues,” correct?

A That’s what it says, yes.

Q And the “they” is the power companies, correct?

A Yes. They were -- yes. Both divisions were involved, Air Quality, Water Quality, yes, permits, with regard to permits, as I read this.

Q And the deposition goes on, on page 31, to identify the power companies as what we now know today as Duke Energy Carolinas and Duke Energy Progress, correct?

A Yes. The primary ones that we're dealing with.

Q Now, Mr. Hart, if you would go back to your prefiled testimony.

A But like I say, this also, this testimony that you pointed out, there's a question that says "Were you aware that Mr. Tom Reeder has taken the position in this case on behalf of DENR that you," meaning Ms. Sullins, "among other former employees -- DENR employees 'didn't do a damn thing with regard to the coal ash'"?

Q And she said "I'm aware of that, but I disagree."

A No. She said "No, I wasn't aware of that."

Q Okay.

A She didn't say I didn't disagree.

Q Well, she --

A We're not -- all I'm saying is Ms. Sullins may not be the best person about whether DEP or DEC was doing something, because apparently DENR is taking the position that she didn't do a damn thing about coal ash. And she says even here "I don't recall specifics. I wasn't involved in most of the meetings with Duke and Progress."

Q But you never talked to her or Mr. Reeder, did you?

A No. I have her deposition.

Q Well, you have it now.

A Yes.

Q You didn't have it when you did your prefiled testimony, did you?

A No. I don't -- I mean, I usually don't talk to regulators when I do these kind of things, but it's not that important to me. What's important to me is whether they complied with the rules, and they didn't comply with the 2L rules. This is saying we were -- they were on our radar for permits. You don't get a permit to contaminate groundwater, right? You can have a permit to do something, but those permits don't give you the ability to contaminate groundwater. So if you contaminate groundwater, you have to address it. You have to do corrective action and you have to eliminate the source and those kind of things.

Q Mr. Hart, if you would look at page 8 of your testimony.

A Testimony -- okay.

Q And I think we went over this earlier, but your first conclusion that you summarize there says that DEC -- the utility industry and DEC knew about the potential for contamination of groundwater from coal ash as early as the 1980s, right?

A Yes.

Q And I think we had a discussion about what you meant by the word “contamination.”

A Correct.

Q We don’t need to revisit that. What do you mean by the word “potential”?

A Well, that there was some reasonable potential that coal ash basins could lead to groundwater contamination. It wasn’t some hypothetical. It wasn’t something that only happened in a few places. There was a reasonable potential that if you had a coal ash basin, you could have groundwater contamination. It wasn’t an absolute, but it was reasonable potential, probably more likely than not, maybe not back in the ‘80s, but certainly there was the potential that something could happen.

Q And Mr. Hart, the -- if I’m understanding your testimony correctly, up through probably the middle part of the first decade of the 2000s, the exceedances of the 2L standards experienced at Duke Energy Carolinas' power plants, whether or not they're at the compliance boundary or not, just exceedances --

A I'm sorry. You cut out for a second. I didn't hear you.
Q Sorry. If I understand -- if I read your testimony, prefiled, correctly, up until the sort of middle of the first decade of the 2000s, maybe a little bit towards the latter part of the middle, the exceedances of the 2L standards experienced at power plants, no matter where -- I mean, whether it's a compliance boundary or not compliance boundary -- were primarily of iron and manganese, correct?
A I think most of them were, but certainly not all of them.
Q Most of them were?
A Most of them were iron and manganese.
Q And iron and manganese are ubiquitous in Piedmont soils, correct?
A Yes, they are.
Q And every single one of the -- of DEC's power plants was built in the Piedmont soils area, correct?
A Yes. The DEC plants, yes.
Q And neither iron nor manganese is a hazardous substance, is it?
A I don't know. I'd have to check. I don't believe iron and manganese -- some forms of manganese

could be. Some forms of iron could be. Ferric chloride or something could be a hazardous substance. I’m not sure.

Q So is it your testimony that the -- I mean, the EPA has lists of hazardous substances. Do you believe iron and manganese are on that list?

A Well, iron and manganese rarely occur just by themselves as hazardous substances. And they’re usually complex with something, so they’re not usually -- a ferric oxide would be iron and oxygen and ferric chloride, and so I don’t know if some of those complexes might be in there, so iron usually doesn’t disassociate itself and just appear as disassociated metal in the environment.

And one of the reasons you find high levels of manganese and iron around coal ash plants is because they create a low oxygen environment, and when you do that, you liberate naturally occurring iron and manganese in the environment. So when you see concentrations, you know, if you have concentrations that are near the standard or slightly above, then you could say that’s background, but if you've 10,000 parts per billion of iron or manganese in groundwater, that can’t be background. It’s not possible without some -- in the

Piedmont without some intervening contamination or some non-natural issue.

Q And Mr. Hart, just make sure I understand. There is a 2L standard for both iron and manganese, correct?

A Correct.

Q And that 2L standard is the same as the drinking water standard, correct?

A What drinking water standard are you talking about?

Q Well, I guess the EPA publishes drinking water standards, does it not?

A Correct.

Q And they're called MCLs, but help me with the -- what the M and the C and the L stand for.

A Maximum contaminant levels.

Q Okay. And there are primary standards and secondary standards, correct?

A For EPA and the drinking water rules, but there are -- there's no analogous in the analog to the 2L standard. There's no primary or secondary standards in the 2L rules.

Q I understand, but I'm talking about the drinking water standards at this point.

A Okay.

Q And the primary standards, as I understand it at least at the very high level that I might understand or not understand, are essentially health related issues or could -- exceedance of those standards could cause some kind of a health related issue, correct?

A Yes. Generally, you can say that, yes.

Q And the secondary standards -- exceedance of the secondary standards is related to essentially aesthetic issues, taste, smell, things of that nature?

A Generally, yes, but you could have a case where there's a secondary standard and it's -- it still has a health effect, but because the taste or odor threshold is lower than, for example, health based effect and they base it upon the aesthetic effects.

Q But in terms of iron and manganese, they're both -- the standards are both secondary MCL standards, correct?

A For drinking water, not for North Carolina groundwater, yes.

Q But the drinking water standard is the same standard as the 2L standard for groundwater in North Carolina, correct?

A That's correct.

Q So Mr. Hart, when you came to the conclusion that Duke Energy Carolinas was not proactive enough in dealing with the DEQ, did you eliminate the possibility that DEQ saw the exceedance of the 2L standards, understood that the exceedances posed no threat to the health of anyone, and decided they had other fish to fry?

A Well, I don't have any reason not to believe that, other than in 2009, DEQ sends that letter to DEC and says we've been getting this data. It's showing us exceedances of the 2L standards. We need to understand where the wells are at your facilities. All we've gotten is just data, right? I don't -- we don't -- we need to understand background. We need to understand the compliance boundary. We need to understand the waste boundary. So at least in 2009 they weren't just -- decided that they had other things to do.

Now, that's certainly the case. DEQ often is overworked and they have limited staff, so that's happened, but that doesn't mean that you can ignore the rules. Just because somebody doesn't issue a Notice of Violation, a Notice of Regulatory Requirement, doesn't mean it's not a violation and it has to be addressed in accordance with the rule.

Q I understand, Mr. Hart. And if you would look at your Exhibit 11.

A My Exhibit 11. Okay.

Q Actually, I think I need another exhibit, but the -- I think we could probably do it this way. The first paragraph of this exhibit, which is a letter to Mr. Allen Stowe from DEQ, indicates that the DE--- that the DWQ, Division of Water Quality, has been reviewing the data and map submitted by Duke Energy on April 30th. Do you see that?

A Yes. Right. In response to their request earlier to provide the map, yes, and a summary of the data.

Q Right.

A There was a letter that preceded this one that --

Q Yeah --

A -- said all we’ve been getting is data; we need maps, we need summary tables, I believe.

Q And without agreeing with your characterization of that letter since we don’t have the letter right in front of us, Mr. Hart, but that’s the letter I was trying to locate in which the DEQ asked for additional information concerning the location of wells, et cetera, correct?

A Right.

Q And if my memory -- my memory of that is it’s sometime in March of 2009, correct?

A I believe that’s correct, yes.

Q And whatever information that the DEQ asked for was, in fact, submitted to the DEQ, at least according to your Exhibit 11, on April 30th, 2009, correct?

A Well, I think -- I don’t think so because I believe that letter also said -- the original letter said to the extent that you have 2L violations, you need to tell us how you’re going to address them.

Q Well --

A And I didn’t see that was provided in this letter.

Q Okay. And then in the -- in the letter dated December 18th, which is your Exhibit 11, the DEQ addresses that issue and says since you submitted all that data, we, the DEQ, have been consulting with our lawyer, the Attorney General’s Office, to figure out whether we actually can ask you to do what we’re asking you to do, correct?

A No.

Q In terms of placing wells at the compliance boundary, et cetera.

A No. What this is saying is whether DEC can use the provisions 2L.0106, which are the corrective actions rules which allow natural attenuation, so it doesn't say -- it just says do we have to do -- is DEC allowed to do natural attenuation under rules that had been promulgated not, I believe pretty -- like 2008 or so that allowed companies to seek or regulated people to seek what they call alternate remediation, which can be by natural attenuation or not cleaning up -- or getting a variance and things like that.

Q Okay. In any event, Mr. Hart, let's just go back to your prefiled testimony concerning the potential for groundwater contamination known to the industry and DEC from the 1980s.

A Okay.

Q I was looking, Mr. Hart, through the authorities that you cite in your testimony, and there appear to be three from the 1980s, correct? The first one is the 1980 EPA TVA Report which is Joint Exhibit 5. It's referenced in your testimony --

A Yes.

Q -- on pages 50 to 51.

A Right. I have to -- I'd have to check and see which roll over from the '80s.

Q And the second one that I found is the 1988 EPA Report to Congress which is Joint Exhibit 13. It’s referenced at your testimony at page 51 and 52. And the third one that I found was your reference to the 1984 Investigation at the Allen plant, which is Joint Exhibit 9, at your testimony pages 57 and 58. If I missed one, just let me know.

A Let me look. You have the March ’80 EPA Effects of Coal Ash Leachate on Groundwater; 1988 EPA Report to Congress; and then the Duke Coal Ash Disposal Report from 1984. Those are the ones that you have?

Q Yes.

A I believe that’s correct, yes.

Q Okay. So these are your sources for the conclusion that as early as the 1980s, the industry and DEC knew of the potential for groundwater contamination, correct?

A Well, they’re some of the sources. I did not attach everything I reviewed as an exhibit. So I believe I did provide some other documents in response to DEC’s request for my files that aren’t necessarily attached as exhibits to my testimony, so I believe there are some others from the 1980s as well.

Q Well, not to belabor it, Mr. Hart, but these are the ones that you actually referred to in your testimony?

A That's right. That's correct.

Q And, again, all of this is in the context of your definition of the word "potential" and your definition of the word "contamination," correct?

A Yes. I would say it's supportive of the testimony summary 1 about the potential for groundwater contamination as early as the 1980s from coal ash basins.

Q Let's take a look at the EPA/TVA report first, Mr. Hart, which is Joint Exhibit 5.

A Okay.

Q And you indicate -- this is page 50 and 51 of your testimony -- that the presence of coal ash leachate within the basins themselves was at high levels, but that groundwater sampling was at lower concentrations, correct?

A Yes. Results of the study indicated that the water in the pour spaces of the coal ash basin contained high levels of TDS, boron, iron, manganese, and sulphate, pH as low as 2, and results of groundwater sampling indicated elevated levels of TDS, boron, iron, manganese, and sulphate, although at lower concentration than in the ash basin water.

Q And you indicate that the lower concentration is attributed to soil attenuation, correct?
A Attenuation mechanisms in the underlying native soil, correct.
Q And the conclusions and recommendations of the report are summarized in Section 2 of the report which begins on page 2.
A Okay. Yes.
Q And let me get to that page. Sorry. So Mr. Hart, tell me what the purpose is of a section of a report that deals with Conclusions and Recommendations.
A Well, it’s conclusions about their -- their findings, and then also recommendations for -- based upon their findings for additional research or action or something like that.
Q And what’s the importance to the reader of the report of the report’s conclusions and recommendations?
A Well, it provides a summary, but it certainly is not intended to replace the actual findings of the report or the details of the report. In other words, you can’t just read the conclusions and recommendations and say I know everything about the report and what it’s going to tell me. You have to dive into the details and the data, as a scientist at least.

Q And I guess, Mr. Hart, my question -- maybe it's not a good question; maybe I didn't phrase it correctly -- but the reason to look back at documents such as this particular one, the 1980 EPA TVA report, or the 1988 Report to Congress, or the 1984 report about the Allen Plant, is to look to see what the industry knew and what the environmental community knew and what regulators knew at those various points in time, correct?

A Yes. I'd say in a general sense, yes.

Q And the purpose for that is to provide historical context around the documents that are being reviewed today in 2020, correct?

A Yeah. I'd say generally, yes.

Q And Mr. Hart, so you --

A Or some other time.

Q Yeah. Well, depending on -- depending on when the reader is actually reading it.

A Correct.

Q So Mr. Hart, your testimony certainly accurately states that -- the EPA TVA report's findings about coal ash leachate inside the basin and the impact of soil attenuation, but my question or my curiosity about it is, is why you didn't go further and state from the report's own conclusions, Conclusion Number 10, which is on page 3, and states soils containing a large percentage of clay are better attenuators than other types of soils, right?

A You asked me why I didn't include that?

Q Yeah.

A I mean, at least from my perspective it's an obvious statement. It doesn't need repetition, from my standpoint. There's no doubt that clay has a -- will attenuate metals from ash leachate or any other source more than sand, and that's true for just about any contaminant. So this is my report, so to me it wasn't a conclusion. It was an obvious statement.

Q Do you think it's obvious to lawyers reading your testimony or Commissioners reading your testimony?

A I don't know, but, you know, to me it's, you know, very clear that there is attenuation, and I say that, in the underlying native soil. So I think I've addressed that in a succinct way rather than replicating every conclusion and recommendation. And that's why I provide the exhibits, too. If someone had a question about what exactly that meant, they could read the actual exhibit.

Q So you don't think that it's important from the standpoint of a fair presentation as a scientist that your testimony should reflect the report's conclusion that clay soils are better attenuators, given that all of DEC's plants are built in clay soils?

A I don't know you can say all of DEC's plants are built in clay soils. Not all of Piedmont, especially as you get deep, as you get close to bedrock, you get into sand. And many of these basins, especially DEC basins, were placed into stream channels or at least surface water conveyance channels, and so rather than being on the top of a hill where you would expect more clay, they were actually put into the bottom of a valley where you're closer to bedrock and closer to sandy soil.

You can't make the blanket conclusion that all Piedmont soil is clay. It is at the surface in most cases, although we do have some areas with bedrock, but there's a great percentage of soil, especially as you get deeper, these basins in most cases were deep and installed in valleys where it is not clay. It is, in fact, a sandy material from the weathering of the underlying bedrock, what we called partially weathered rock.

Q Well, let's take a look at your -- the second document, Mr. Hart, which is the EPA Report to Congress, Joint Exhibit Number 13. You address the Joint -- the

Report to Congress at pages 51 and 52 of your testimony, right?

A Yes. Yes.

Q And on page 52, the first full paragraph on that page you indicate that the report -- in the report EPA documented current waste disposal practices on a state-by-state basis, correct?

A Yes.

Q But you didn’t actually provide in your testimony the Commission with the details of what the EPA documented, do you?

A Yeah. I was focusing on, in this case, the -- the facilities for North and South Carolina.

Q Well, if you --

A That's all I'm saying.

THE WITNESS: I lost power on this thing, computer. I’m sorry. Go ahead.

MR. MEHTA: You all right?

THE WITNESS: Well, some of these I have. I lost my -- I guess I unplugged the power cord. I’ve got two computers here, one with the documents on it and one --

MR. MEHTA: Well, tell me when you’re ready to proceed.

THE WITNESS: Go ahead. I’m sorry. Just waiting for it to reboot.

Q Do you happen to have available, Mr. Hart, the testimony of Marcia Williams, or is that in your computer that’s rebooting?

A It is rebooting, but I can pull it up here, I hope.

Q Well, again, just subject to check, you can always check me, I’m going to refer to page 73 of her testimony where she indicates that the report indicates that only 10 percent of the 483 surface impoundments were lined, and in EPA Region 4, which essentially is the southeastern United States and includes both North and South Carolina, less than 2 percent were lined, correct?

A I’ll have to bring up her testimony, but what page are you on?

Q Seventy-three (73).

A Okay. Sorry.

Q Did I accurately summarize what she said in terms of the percentages of lined and unlined ponds?

A Yes. That’s correct.

Q But you didn’t think it was important to provide the details of what the EPA documented in its report on lined and unlined ponds in the paragraph where you said the EPA did state-by-state surveys of those ponds, correct?

A Yeah. Well, my position isn't on whether ponds are lined or unlined. They were unlined, so that's a given fact we have. The question is once groundwater -- from my standpoint, at least, is once groundwater contamination was detected, what did DEC do in response to that in accordance with North Carolina regulations? So it's really not important to me whether it was lined -- there were -- whether people were doing, lining or not lining impoundments, as much as it was about what we were seeing. I think I do talk about some lining, but it was more important to me to see what people knew about groundwater contamination from the unlined lagoons.

Q Well, if you go on, I guess down at the bottom of page 52 --

A I'm sorry. Of what?

Q Of your testimony.

A Yeah.

Q You talk about various technologies available, for example, lining, liners to deal with what you indicate the report said was a "leaky pond issue," correct?

A Right. That lining was becoming more common because of concern that groundwater contamination may occur from leaky ponds.

Q Well, did you mean by that paragraph to give the reader of your testimony the impression that DEC should have been retrofitting its ash basins with liners back at this time frame?

A You talking about in 1988?

Q Sure.

A No. That was not my intention. My intention is to say that in response to the ground--- that during this time period there was knowledge that unlined lagoons, such as at the DEC facilities, could lead to groundwater contamination, which is, in fact, what -- what was found when groundwater monitoring started. So it shouldn’t have been a concern -- I mean, it shouldn't have been a surprise when groundwater monitoring indicated that there was contamination associated with the ponds. I mean, so from that standpoint what I’m saying here is lining was becoming more common because people were finding groundwater contamination associated with leaky ponds.

Q So if a reader came away with the impression that you were advocating that liners -- ash ponds back then should have been retrofitted with liners, that would be a misimpression, correct?

A That's correct. Now, once they found groundwater contamination, I mean, there are certain things that can be done to limit contamination, further migration, and control the source, which could include lining, but there's many other things that could be done, too, as I discussed in my testimony.

Q And the EPA itself made no recommendation that existing ash ponds should be retrofitted with liners, correct?

A I don't recall that. What, in this document?

Q Yes.

A I don't recall that.

Q And this document, just like every other document from the historical time period that we've been looking at, has a section on Conclusions and Recommendations, does it not?

A It does, yes, but, again, that's not intended to be a substitute for the actual data or foundation behind the report, in my opinion.

Q And the conclusions and recommendations of the EPA in its 1988 report are in Chapter 7 of the report, correct?

A Yes.

Q And if we look at Chapter 7 -- I guess it starts -- it’s probably pretty far down at the -- towards the end.

A Hold on. Twenty-one (21).

Q Yeah. It’s your Exhibit 21 and Joint Exhibit 13.

A Yes.

Q Looks like it’s -- well, again, in Joint Exhibit 13 because the pages are sequentially numbered, it’s Doc. Ex. 6710, but if you’re looking at your exhibit, you’ll just have to find Chapter 7.

A I found Chapter 7.

CHAIR MITCHELL: Mr. Hart, you are trailing off. Can you make sure that you are speaking directly into or towards your microphone just so the court reporter gets your complete sentences?

THE WITNESS: Okay. I’m sorry about that.

CHAIR MITCHELL: Thank you.

A Yes. I’m on Chapter 7. Sorry.

Q And if you go to page 7-7, which in Joint Exhibit 13 is Doc. Ex. 6716, there’s a section of the Conclusions and Recommendations that says -- that talks about evidence of environment transport of potentially hazardous constituents, correct?

A What page, 7-7?
Q 7-7.
A Okay. What number are you talking about, bullet number?
Q It's Section 7.2.5 at the --
A Okay.
Q -- bottom of the page. Are you there?
A Yes.
Q And the first conclusion of the EPA is that migration of potentially hazardous constituents has occurred from coal ash combustion waste sites, correct?
A Yes.
Q So they indicate that they actually have seen what you say was found, for example, at the Allen plant?
A Right.
Q Not that it's hazardous concentrations, but that constituents were in groundwater, correct?
A Right. Above the drinking water standards.
Q Well, at Allen they were probably not above the drinking water standards, but they perhaps were above whatever the 2L standards were at the time, correct?
A I'd have to go back and check. I was talking about this. They're saying that there are exceedance -- I'm talking about the 1988 report.

Q Okay.

A About how there are exceedances of drinking water standards for cadmium, chromium, lead, selenium, and arsenic.

Q Right. And so the EPA, in fact, found that there were exceedances of drinking water standards at some power plants, correct?

A That’s correct.

Q And the second conclusion that they drew was that this, what they called contamination, does not appear to be widespread, correct?

A Right. It says -- yes. Not widespread, but many utility waste management sites had at least one exceedance. Not widespread, but at least some exceedances, yes.

Q Okay. And the third conclusion that the EPA reached was -- and this is on page 7-8, number 3, when groundwater contamination does occur, the magnitude of the exceedance is generally not large, correct?

A Right. They’re usually 10 to -- well, I guess and that’s relative. They tend to be no more than 10 to 20 times the primary drinking water standards, although some observations were greater than a hundred times the primary drinking water standard.

Q And the fourth conclusion that the EPA made with respect to groundwater impacts was human populations are generally not directly exposed to the groundwater in the vicinity of utility coal combustion waste management sites, correct?

A Correct.

Q And the report makes recommendations in addition to conclusions, does it not?

A After it discusses evidence of damage from coal ash plants, it does have recommendations, yes.

Q And that's starting on page 7-11, correct?

A Yes.

Q And for the Joint Exhibit 13 reference, it's Doc. Ex. 6720. And the recommendations are there to provide guidance, the EPA's guidance about what it thinks ought to happen in the future, correct?

A Well, it says they're preliminary, but there could be other recommendation, but, yes, generally the recommendations would have some information on additional studies or how to address some of these concerns, yes.

Q And the -- I mean, Ms. Williams was the head of the office that wrote this report, so we can ask her perhaps what's meant by preliminary, but the first recommendation is that the EPA has concluded that coal combustion waste streams generally do not exhibit hazardous characteristics. Do you see that?

A Yes.

Q And that the EPA doesn't intend to regulate it as a hazardous -- as a hazardous substance under Subtitle C. Do you see that?

A I read this as it's not a hazardous waste.

Q Hazardous waste. Excuse me.

A Not a hazardous substance.

Q Yeah. We're talking RCRA, not CERCLA. I was mixing up those terms. There's not a hazardous waste under the RCRA Subtitle C, correct?

A Correct.

Q And they go on to say that their conclusion or at least tentative conclusion is that "Current waste management practices appear to be adequate for protecting human health and the environment." Is that right?

A Where is that?

Q The very next sentence after the underlined sentences in that paragraph.

A Right. EPA's tentative conclusion.

Q And its tentative conclusion is that "Current waste management practices appear to be adequate for protecting human health and the environment," correct?

A That's what it says. Now, I -- I read this under the context of RCRA. In other words, it shouldn't be a RCRA hazardous waste if it's under that heading.

Q Well, the EPA arrived at that conclusion and made the recommendations that it made knowing that 98 percent of the ash basins in the southeastern United States were unlined and that every single one built by Duke Energy Carolinas at the time was unlined, correct?

A Yes, I believe so. Yes.

Q And did you not think that that is a conclusion that ought to be presented in your testimony in order to make it fair and balanced?

A Well, I was -- I mean, you can use it for different things. I mean, there's -- you know, that's why I attached the document itself, because there's no way I could go through all the conclusions and recommendations in these reports. I mean, as I mentioned before, it also has a discussion of the Allen plant, where it says high concentrations of manganese are in groundwater at this facility. It's going to continue to migrate. It's not in steady state, and there's concentrations that are, you know, 120,000 parts per billion versus the standard of 50. So I could have included that as well, but I didn't. There's no way I can include everything in this report, that, to me, I was just using it for some of the information that I presented here. But there was no intention on my part certainly to not include a balanced report. I even say that, that --

Q So Mr. Hart, if you --

A If I can finish my -- please.

Q Sure. Oh, of course. I'm sorry.

A -- that, you know, the understanding of groundwater contamination evolved over time. It did, associated with coal ash plants. So, you know, the intention was not to -- if I didn't include some specific recommendation in a 386-page document, it wasn't intention to hide it. That's why I attached it. There's just no chance that you could include all the recommendations and conclusions in the report. I was providing the reader some information that I gleaned from it that was important to my evaluation.

Q Mr. Hart, the EPA was clearly aware of the underlying data that you just recited about the Allen plant, was it not, when it wrote this report?

A The EPA was, yes, and it's a violation of the 2L standard, to which DEC did nothing until it was required to do so in 2014.

MR. MEHTA: Chair Mitchell, I'm going to move on to a different subject. I don't know if this is a good time for a lunch break, or I can keep going.

CHAIR MITCHELL: Why don't you keep going, Mr. Mehta. We'll take a lunch break at 12:45.

MR. MEHTA: Very good.

Q Mr. Hart, let's take a look, then, at the third of your 1980s documents, which is the 1984 Duke Report on Allen which is Joint Exhibit 9. And I think you found it earlier --

A Yeah. I had it earlier. Yeah. Here it is.

Q -- by reference to whatever it was marked as in the prior case, which I think was a Wells cross exhibit.

A Yeah. I have it.

Q And Mr. Hart, you talk about this report at pages 57 and 58 of your testimony, correct?

A Yes.

Q And that's placed in the section, or the sort of lead-in question is about your review of internal -- or documents internal to DEC regarding actual or potential groundwater contamination, correct?

A Yes. I'm sorry. Yes. It's in that section, but --

Q This particular document, though, Mr. Hart, was published, was it not? I mean, it’s not just an internal DEC document, correct?

A I don’t know. I don’t know that. The report by Little, and I think this was done in parallel with the latest Little report, was published, but I don’t know if this one was published.

Q I guess on that subject, Mr. Hart, if you -- you indicate in the last line of page 20 of your prefiled testimony, starting there and going on to the top of page 21, that one of the “proven” damage cases cited by the EPA in the document under discussion there, which I believe is the 2010 Proposed CCR Rule, correct?

A Yes. And it’s referencing the 2007 Coal Combustion Waste Damage Assessment report.

Q Right. And you indicate there that one of the “proven” damages -- damage cases is the Belews Creek fish kill situation, correct?

A Correct.

Q And certainly, DEC did not hide that incident, did it?

A Not that I’m aware of. It would be hard to hide a fish kill.

Q And they actually do know that it was the subject of a published document because Joint Exhibit 11 is that document. It’s a -- the proceedings of some engineering group, proceedings of a symposium sponsored by the Energy Division of the American Society of Civil Engineers in conjunction with the ASCE Convention in Detroit, Michigan, October 24th, 1985, correct?

A Are you -- I’m sorry. Are you referencing to --

Q Yes. I’m referencing Joint Exhibit 11.

A Oh, okay. Okay. I don’t have that, but --

Q And this particular incident, the fish kill, impacted surface waters, basically Belews Lake, correct?

A Yes. That’s correct.

Q And DEC addressed the issue by, among other things, modifying its production to shift to dry handling of the fly ash produced by the Belews Creek power plant, correct?

A That’s correct. So the question is if they could -- from my standpoint, is if they knew there was an issue with surface water and they addressed it with dry ash handling, they had -- so they address this issue with metals. They later find there’s a groundwater issue that have metals. It’s not addressed. So is surface water more important than groundwater, I guess, in Duke Energy’s beliefs? That’s the impression you get, at least for me.

Q Well, that -- that's the impression that you draw from the confluence of events here, correct?

A Well, yeah. And they certainly -- because there's a fish kill, they addressed it, right? But there's no fish kill at groundwater, so even though it's a resource of the state, it somehow is less important from Duke Energy's standpoint. That's the impression that I got.

Q Well, we'll let Mr. Wells and Ms. Bednarcik, when she's back on, speak to that, because I'm really trying to just examine you on your testimony regarding these documents.

And in any event, Mr. Hart, the selection of that particular remedy, the conversion of fly ash to dry handling, was done in conjunction with the DEQ, was it not?

A I don't know. As far as I know, it was. Now, this is 1984, so I don't really have any documents from that time period related specifically to that, but I would think so, yes. Yes. So they certainly had the ability as early as 1984 to convert facilities to dry fly ash handling to reduce the concentrations of metals that were entering surface water, and that same water was also infiltrating into groundwater.

Q Mr. Hart, the plant modifications did not include dry ash or dry handling of bottom ash at the Belews Creek facility, did they?

A It did not, not until 2018.

Q Yeah. And despite continuing to sluice bottom ash to the Belews Creek ash ponds, this fish kill issue did not resurface, did it?

A Well, no. I mean -- yeah. So fly ash would generally tend to have much higher concentrations of metals in it than bottom ash, so it would have been less likely to have an issue. But I understand they also -- not only did they convert to dry handling, my understanding is they also added, I believe, ferric chloride to help settle out some of the metals to the water before it was disposed in the basin. Now, that leads to another reason why you have high concentrations of iron, potentially, because you added a treatment chemical to remove some of the metals.

Q And back to the 1984 Allen report, Mr. Hart, that you address at page 57, and you indicate on page 57 of your testimony --

A Okay.

Q -- that the report dealt with a study of leachate from coal ash and potential impacts upon groundwater, correct?

A Yes.

Q And the Executive Summary of that report, Mr. Hart, which is Joint Exhibit 9 --

A Okay.

Q -- it's on Doc. Ex. 9395 in the joint exhibit, but it's essentially the first page before page 1 in the report that you're probably looking at, it's an unnumbered page --

A Yes. Executive Summary.

Q -- it indicates, starting in the middle of that paragraph, "Groundwater monitoring in 13 test wells installed by Duke Power around a retired inactive 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," correct?

A Yes, but what they're talking about is further downgradient of the ponds, not next to them.

Q I understand. And the second sentence says "Additional groundwater monitoring and soil testing from the same sites done by an EPA contractor," and that's Arthur D. Little, correct?

A That's my understanding, yes.

Q So additional groundwater monitoring by Arthur D. Little for the EPA "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 basins," correct?

A Correct.

Q And the conclusion that the Executive Summary draws is the last sentence, "These field and laboratory studies confirm that wet disposal of coal ash by Duke Power has no significant impact on groundwater," correct?

A Well, yes. That's what it says.

Q Well, why didn't these conclusions in the Executive Summary make their way into your testimony, Mr. Hart?

A Well, they do. I clearly say that there was groundwater contamination. "Results of groundwater analyses conducted near the ash basins indicated that concentrations of arsenic (up to 112.5 micrograms per liter versus the 2L standard at the time of 50 micrograms per liter) and selenium (up to 19.5 micrograms per liter versus the 2L standard at the time of 10 micrograms per liter) were detected above standards in two of the wells;

however, the groundwater impacts did not extend downgradient from the ponds."

And I go on to say -- and I'm reading on page 57, lines 19 and on, "The study indicated there was a leachate plume emanating from the ash basin into groundwater, but the apparent high ion exchange capacity of the underlying soil limited downgradient migration." I did. Why are you accusing me of not including the recommendations when I -- I mean, the summary when I did?

Q Well, I'm looking for some acknowledgement, Mr. Hart, in your testimony, and I didn't find it, perhaps you can show it to me, that "These field and laboratory studies confirm that wet disposal of coal ash by Duke Power has no significant impact on groundwater."

A Because I disagree with the conclusion. It's not accurate. It did have an impact on groundwater. It didn't extend downgradient. And this is a Duke Power report prepared for Duke Power. Of course, they're -- they may not say that their coal ash is going to have an impact on groundwater. It did have an impact on groundwater. We see it in this report and we see it in the Arthur D. Little report. To say that it had no significant impact ignores that fact that there are groundwater rules and standards. It did not extend downgradient. It also ignores the fact that the ion exchange capacity may be exhausted in the future, and it was. It did lead to groundwater contamination.

Q Mr. Hart, look, if you would, at page 40 and 41 of your deposition testimony.

CHAIR MITCHELL: All right. Mr. Mehta, I believe this is a good time to break for lunch.

MR. MEHTA: Chair Mitchell, actually, if we could get one question in, we will be done with the subject and can break and come -- go to a completely different subject.

CHAIR MITCHELL: All right. Well, I'll allow you to proceed. You are standing between us and our lunch break.

MR. MEHTA: I understand.

CHAIR MITCHELL: I'll allow you to proceed.

MR. MEHTA: And I will try to be very brief. Of course, one question for a lawyer always turns into a few more, but --

CHAIR MITCHELL: I'm very aware of that.

MR. MEHTA: I understand.

Q So Mr. Hart, are you at pages 40 and 41 of your deposition, which is Exhibit 1?

A Yes.

Q And in the -- at the very bottom of page 40, your testimony concerns the report of the Allen plant, which is what we’ve just been talking about, the Joint Exhibit 9, correct? Is that right?

A Well, I don’t see --

Q Well, I’m looking at page 40, line 24,”...even the report that was done at the Allen plant...” Do you see that?

A Right.

Q And you indicate the conclusion from that was that there was groundwater contamination, but it wasn’t migrating very far. Do you see that?

A Yes.

Q And you indicate that they felt, "they" meaning the authors of the report, felt there was significant attenuation capacity in some of the soils. Do you see that?

A Yes.

Q And then you say “Now, it turned out to not necessarily be correct, but that was the conclusion at the time.” Do you see that?

A Yes.

Q And I asked you at line 6 on page 41, “Are you quarreling with the conclusion at the time,” correct?

A Correct.

Q And your answer was, starting on line 8, “No. I think over time a lot more data was developed, which is not uncommon,” correct?

A Correct.

MR. MEHTA: Chair Mitchell, I’m done. It took three minutes. Sorry. But we can move on to a different subject after lunch.

CHAIR MITCHELL: All right. Well, we will -- we will take our lunch break now. Before we go off the record I’d like to ask that Duke refile, at its earliest convenience, the witness list. That is the list that indicates order of witnesses yet to appear in this proceeding. And I’d also ask Duke that you all work to get updated cross examination times from the parties. It is critical for our planning purposes and managing the other business that this Commission must conduct that we have a good and accurate sense of how long we’re going to be in this hearing. So I’d ask that everyone please be as forthcoming and as accurate as they can be with their cross examination times.

All right. Let’s take our lunch break. Let’s come back on the record at 2:00.

(The hearing was recessed, to be continued on September 9, 2020, at 2:00 p.m.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket Nos. E-7, Sub 1214, E-7, Sub 1213, and E-7, Sub 1187, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 14th day of September, 2020.

Linda S. Garrett

Linda S. Garrett, CCR
Notary Public No. 19971700150