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DATE: Tuesday, September 24, 2019

TIME: 9:00 a.m. - 12:28 p.m.

DOCKET NO: E-22, Sub 562 and E-22, Sub 566

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Application of Virginia Electric and Power Company,

d/b/a Dominion Energy North Carolina,

for Adjustment of Rates and Charges Applicable to

Electric Service in North Carolina

And

Petition of Virginia Electric and Power Company,

d/b/a Dominion Energy North Carolina,

for an Accounting Order to Defer Certain Capital and

Operating Costs Associated with Greensville County

Combined Cycle Addition

VOLUME 5

Noteworthy Reporting Services, LLC

A P P E A R A N C E S:

FOR VIRGINIA ELECTRIC and POWER COMPANY d/b/a
DOMINION ENERGY NORTH CAROLINA:

Mary Lynne Grigg, Esq.
Andrea Kells, Esq.
William Dixon Snukals, Esq.
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27614

Robert W. Kaylor, Esq.
Law Office of Robert W. Kaylor, P.A.
353 East Six Forks Road, Suite 260
Raleigh, North Carolina 27609

Horace P. Payne, Jr., Esq.
Assistant General Counsel
Dominion Energy Services, Inc., Law Department
120 Tredegar Street
Richmond, Virginia 23219

A P P E A R A N C E S   Cont'd.:

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES I:

Warren K. Hicks, Esq.
Bailey & Dixon, LLP
Post Office Box 1351
Raleigh, North Carolina 27602-1351

FOR NUCOR STEEL-HERTFORD:

Joseph W. Eason, Esq.
Nelson, Mullins, Riley & Scarborough, LLP
4140 Park Lake Avenue, Suite 200
Raleigh, North Carolina 27612

Damon E. Xenopoulos, Esq.
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson Street, NW
Washington, D.C. 20007-5201

A P P E A R A N C E S Cont'd.:

FOR THE USING AND CONSUMING PUBLIC, THE STATE
AND ITS CITIZENS:

Jennifer Harrod, Esq.
Margaret A. Force, Esq.
Theresa Townsend, Esq.
North Carolina Attorney General's Office
114 West Edenton Street
Raleigh, North Carolina 27614

FOR THE USING AND CONSUMING PUBLIC:

David Drooz, Esq.
Dianna Downey, Esq.
Lucy Edmondson, Esq.
Heather Fennell, Esq.
Layla Cummings, Esq.
Gina Holt, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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P R O C E E D I N G S

CHAIR MITCHELL: Okay. Good morning. Let's go back on the record, please. Mr. Eason, I think you are -- you're up.

MR. EASON: Thank you.

ROBERT E. MILLER and PAUL B. HAYNES,

having been previously sworn,

were examined and further testified as follows:

CONTINUED CROSS-EXAMINATION BY MR. EASON:

Q. Good morning, Mr. Miller, Mr. Haynes. How are you?

A. (Paul Haynes) Good morning.

Q. I'm Joe Eason, and I'll continue for Nucor.

Mr. Haynes, in your rebuttal testimony, just to remind us where we were, on Line 13 of Page 49, you indicated that the ROR -- ROR Index as a result of the stipulation in the 2016 rate case increased the Nucor Steel class from .43 to .75; is that correct?

A. Yes.

Q. Thirty-two (32) basis points?

A. Yes.

Q. And that metric, ROR, that's rate of return; is that right?

A. Yes, it is.

Q. And it was applied specifically when you calculated, according to Line 12, on non-fuel base rate increase; is that right?

A. Yes.

Q. And that's because non-fuel is not entitled by law to a rate of return; is that right? It's a pass-through.

A. That's correct.

Q. And so to calculate that metric consistently across all indices, it should be limited to non-fuel expense?

A. The -- we can calculate it for the non-fuel revenues, expenses and rate basin plant. But I believe in the Commission's 2012 order and again in our 2016 case order, the Commission recognized that for purposes of determining the increase in total base revenues, it was proper to -- and appropriate to include both base non-fuel and base fuel in determining the total percentage change and in also calculating the rate of return.

But I will say that, ideally, in -- and Mr. Miller can address this as well. Ideally, in a cost-of-service study, fully adjusted, the fuel revenues and fuel expenses are supposed to be equal. We run what's called a deferred fuel account to track any over/under recovery and that should equalize it within the cost of service.

So there should be no impact on the rate of return, but there will be an impact on the percentage change in revenues when you include in your present revenues both base non-fuel and base fuel.

Q. Again, my question was isn't it a matter of law in this state that you do not earn a return on non-fuel -- excuse me, on fuel expense; it's a pass-through?

A. That's correct.

Q. And the ROR Index is calculating the return on a rate base item, not an item of expense; is that right?

A. That's right.

Q. And so the -- pardon me. The adjustments that are made that reflect whether fueled expense are collected through the base tariff or the revenue tariff isn't supposed to affect those dollars for which rates of return are earned as a matter of law, correct?

A. I'm not -- I'm not sure it -- I can't speak to it -- whether or not it's a matter of law. But in terms of the calculation, that is correct.

Q. Now turning to the next page, you indicated that in the proposed original case of the Company that ROR Index, the -- on non-fuel base revenue was proposed to go up to .8, another five basis points, from .75, which is where it was established in the 2016 general rate case, correct?

A. That's correct.

Q. Now, the next sentence is interesting to me. It says, "In the Company's supplemental filing, Schedule NS had a ROR Index" -- that's the same non-fuel total cost, correct?

A. Yes. Yes.

Q. In fact, that's the only thing this Commission's focusing on in this docket, because fuel, whether it's base or rider revenue, is going to be addressed in Docket -- what is it, 579? Excuse me. Yeah, 579, the fuel docket.

A. Well, we -- we did file a fuel case recently, but the -- the Commission is resetting or re-establishing what the base fuel rate is in this proceeding. That -- that's a matter of procedure in general rate case.

Q. Yeah, but it's still fuel dollars.

A. It -- it is still fuel dollars, yes.

Q. Now, the -- the verb -- Schedule NS in your supplemental case had a ROR Index, so this was non-fuel only, of .79.

Does that mean there was a target or that's just what actually fell out when the revenues and expenses were supplemented?

A. Okay. If you -- give -- give me a minute. I want to make sure I'm looking at the --

Q. Right.

A. -- the proper document.

Q. It's Line 5 on Page 50 of your rebuttal case.

A. So this is going to be from Mr. Miller's Supplemental Schedule 4. And -- and he can speak to this as well, but in his Supplemental Schedule 4, in what's called the fully adjusted cost of service, after -- after he has accounted for all the ratemaking adjustments that Company Witness McLeod made in determining the cost of service, Mr. Miller allocates those to the customer classes. And before any increase, the Rate of Return Index at that point in time was .79 based upon those adjustments in our supplemental filing.

Q. Okay. But that's -- that's a -- results in an -- it's an actual calculation. It's not based on a target being assessed or assigned by the Company, correct?

A. That's correct.

Q. So --

A. That happens in the next box down in Mr. Miller's Schedule 4.

Q. But the nominal .75 established in 2016 had produced four more basis points, or 36, so it actually had gone up to seven -- .79?

A. Yes.

Q. So a nominal 80 would, assuming past proved to be prologue, would be higher than 80 on a supplemental three to four years out?

A. Yes, it would. But once again -- and I'll let Mr. Miller speak to this -- there was a different series of accounting adjustments that got to this fully adjusted cost of service. So it might be appropriate if he spoke to that.

A. (Robert Miller) Sure. For my Schedule 4 in this case, the supplemental version, there are four boxes. You'll see the first one is the per books class rate of return, which just deals with cost of service as-is. The second shows the effect of annualizing the revenues for each customer class. And the third, the one that we're discussion -- discussing, carries the accounting adjustments down to the class level, the accounting adjustments made by Mr. McLeod.

In this case, Nucor ended up with a .79, but I don't know that that's necessarily indicative that a .75 will produce a .79 in the future. First of all, just mathematically, the Rate of Return Index is just a -- sort of a snapshot, as compared to the jurisdiction as a whole.

So if you look at the rate of return for Box 3 in 20 -- the -- this 2019, my Supplemental Schedule 4, the rate of return was 4.9316. If you look at the rate of return from the 2016 case, after the revenue increase where Nucor did have a .75 index, their rate of return was actually 5.4855. So the company actually had a higher rate of return on Nucor proposed under those rates than they actually recovered from the rates for 2018.

Q. But now that second 5.44, is that with or without fuel revenue?

A. As you discussed, the fuel revenue's a pass-through. So there's a corresponding increase or decrease in -- in both these cases in fuel expenses in addition to fuel revenues. So in terms of the effect on the Rate of Return Index or the rate of return, there actually will not be a significant change in -- in the -- the rate of return due to fuel increase or decrease, as long as it's accompanied by expenses, as appropriate.

Q. So when you say significant, there is an adjustment to the rate of return based on including non-fuel revenue -- excuse me, fuel revenue in the calculation?

A. Certainly. So if you look at my Stipulation Schedule 4, the schedule functions in a similar fashion to the Supplemental Schedule 4. But as per -- as -- in addressing the testimony of Public Staff Witness Floyd, we added a -- an additional box showing the effect of a base fuel revenue reduction.

And so if you look at that Box 5, which is on the second page, you'll see that there is a decrease in revenue shown and there's a slight increase in adjusted net operating expense. The reason for that is that the uncollectible expense related to the base fuel is not considered part of base fuel rate. So that's actually accounted for in the base non-fuel revenue increase. But that would be about $6,000.

So you'd really end up with almost no significant adjustment in net operating income. There's probably a little bit of rounding that goes into that, but I think it would be less than a thousand dollars. And as you can see that -- there was -- if you -- going on the calculation as it was, there was a .0009 percent effect on rate of return from the base fuel decrease.

Q. Again, though, so what's happening is -- is expense dollars are adjusting the return on the rate base that, by law, can include fuel dollars?

A. The expenses and the revenues are matching. Like I said, aside from the uncollectible expense and -- which is accounted for elsewhere and maybe some rounding, and there's no significant impact in rate of return.

Q. Now, Mr. Haynes, you then in this rebuttal case proposed, in light of .75 having actually produced in the Supplemental .79, as well as the testimony of Nucor's witnesses, that a rate -- ROR Index -- and that is, again, a non-fuel index -- would be appropriately set at .75. That is left where the Commission had it in the 2016 general rate case.

A. (Paul Haynes) Yes, that -- that is correct. But -- but my reasoning was not because the Commission did that in the last case. I -- I conducted an analysis in my rebuttal testimony, and that I explain in my testimony, but the analysis is -- is in my Rebuttal Schedules 2 and 3, where I looked at the benefit, the way I see it, that the Schedule NS Nucor class has on the Company's system and allocation of costs to the North Carolina jurisdiction.

If we did not have a special contract service arrangement with Nucor, there would be significant additional load on the company's system during the peak hours. Because of our service arrangement with Nucor, there's a significant reduction in peak load during the summer and winter peak hours because we -- we ask Nucor to curtail a significant portion of their load and they do that.

So that brings some benefit and cost allocation to the Company's -- the Company and the Company's customers in North Carolina, and I believe it is appropriate to recognize that in the Rate of Return Index.

And -- and I know it -- I made this point a few times yesterday with Mr. Xenopoulus. I want to emphasize in my rebuttal testimony on the very last Page 50, Line 8, I say I believe it is appropriate to target -- target an ROR Index of 0.75.

That's where I think they should ultimately be. But in the context of the Stipulation and the significant reduction in revenues and the level of base fuel revenues, we have an agreement with the Public Staff that every class should share in the -- in the change or increase in base revenue. So every class has to have some positive increase.

So I could not take the Schedule NS class all the way down to an ROR Index of 0.75, even though I said that's appropriate to target, because of the Stipulation. And I believe the Stipulation brings benefits, a significant reduction in the revenue requirement in this case from where the company was in our direct filing at approaching $27 million down to about $8.6 million in base non-fuel revenue.

And that helps all of the Company's customers, including Nucor. It reduces our original revenue requirement allocated to Nucor of -- of a little over $2 million down to $483,083 on a base non-fuel. Considering the base fuel decrease of $424,000, their total base revenue increase is only $58,850. If we took them to a .75 index, they would have a base non-fuel decrease of $68,000 and a total base revenue decrease of $492,255, and that would violate the Company's agreement with the Public Staff to have all the classes share in the base revenue increase.

Q. To just -- so if I'm sure -- I understand, the benefits that you're addressing is -- are associated with the fact that if Nucor interrupts its production of steel, as requested during peak -- potential peak hours, the benefit -- the detriment is largely the disruption of operations, but the benefit is shared with all ratepayers in the Company's -- within the North Carolina jurisdiction, because it's reducing the allocation factor ascribed to all customer classes in this jurisdiction?

A. Yes. But then we do try to represent that fairly in setting a Rate of Return Index for the Schedule NS class. Otherwise, we would try to have an -- an index target of 1.0 for the Schedule NS class and they would be looking at a significant revenue increase.

Q. But --

A. But we're trying to give the -- recognize our arrangement with Nucor, asking them to firmly reduce their load when we call them to on peak -- peak load conditions in the winter and the summer. So it -- it does cause them to change their operations, not manufacture their product. So we give them -- I've given them a discount through this Rate of Return Index.

All I'm saying here is the discount that I believe is appropriate to target to get them to a .75, I could not achieve that total target index because of the Company's Stipulation with the Staff that everyone shares in the increase, which I think is an appropriate outcome in this case. The Stipulation has a paragraph near the end where it talks about no party kind of retained -- or every party kind of retains their own issues, but for the purpose of overall settlement, there's sort of a meeting of the mind and coming together that this settlement or this Stipulation properly resolves all matters in this case in a just and reasonable way for all customers.

Q. Now, the Stipulation testimony that you filed, there was no text addressing the change in the -- whether it's called target or forecasted or proposed ROR Index, that total non-fuel index -- there's no textual indication that instead of being .75, it was a different number. That -- that is only located in the numbered exhibits, the spreadsheets. Is that right?

A. We -- the -- there -- there is in the Stipulation, Section 6 -- this is on Page 10 of the Stipulation. It's -- it's little -- little three. It's about the middle of Page 10.

It says, "In meeting the provisions of (i) and (ii)" -- we can certainly go back and read that -- "in apportioning the approved revenue requirement to the customer classes, awareness and consideration shall be given to the Rate of Return Indexes for the LGS and 6VP classes being above 1.20 and an appropriate Rate of Return Index for the Schedule NS class."

And -- and by appropriate and what was -- what was meant there is recognizing that there is some value in having a special arrangement with Nucor that curtails their load during peak conditions. The reason we didn't put the .75 target in there is we knew that would not be achieved and meet the Company's and the Public Staff's agreement to not have -- or to have all classes share in the base revenue increase.

Q. And that follows from the next sentence, which isn't really part of subparagraph three. It's -- that you're referring to in the Stipulation agreement. There's just a textual sentence that's dropped in after little sub (i), (ii) and (iii) is that the parties agree that all classes should share in the total base rate revenue increase. That's the provision you had alluded to earlier.

A. Yes.

Q. Was that proposed by the Company or the Public Staff?

A. It was -- that was in -- in my -- the principles I outlined in my prefiled direct testimony, I said all parties should share in the base non-fuel increase.

On -- on behalf of Public Staff, Mr. Floyd has -- had a provision that says all parties should share I believe in the total base revenue increase, including both base fuel and base non-fuel revenues. And it was in the context of -- of that part of his testimony that he pointed out that -- that -- that my action and my direct testimony had not complied with Commission orders in the

2012 rate case and in the Company's Stipulation and order in the 2016 rate case to recognize both base revenue -- base non-fuel revenue and base fuel revenue in the determination of what constitutes an increase and a percentage increase in total base revenue.

Q. But does that mean that the ROR Index, which is what's referenced on the piece of paper, is calculated differently than it is when it's referenced in your testimony?

A. It -- and -- and I'm going to refer to Mr. Miller. I think he's addressed this, but it might be appropriate that he walk through this with the -- the Stipulation testimony. But you will see that he has a base non-fuel impact, a base fuel impact and then a total base revenue impact. And -- and he explained this earlier, but it might be appropriate if he just addresses this one more time.

Q. And just for the record, that's off of Schedule 4 of his testimony, Pages 1 of 2 and 2 of 2?

A. (Robert Miller) So, yes, this would be Schedule 4 of my testimony that summarizes this information. Actually, if you look at Schedule 3 of my supplemental -- my Stipulation schedule -- schedule -- sorry. Look at Stipulation Schedule 3.

You can look at Pages 15 and 16, which show the total North Carolina jurisdiction. But the pages beforehand show each class, and then these two pages show the summary total of -- of all lines for each class. And let me know when you're --

Q. I'm sorry. I'm having to borrow counsel's. I only had brought --

A. Sure.

Q. -- the ones that I thought were relevant. Thank you.

A. Sure. So --

Q. Go ahead.

A. So as I said, Schedule 4 is a summary of Schedule 3. It's pulling all of its information from this schedule. And if you look at Pages 15 -- really, 15, you'll see kind of just sort of a very basic income statement sort of set up here where we've got operating revenues, operating expenses. To get a net operating income, you have a few adjustments and you get an adjusted net operating income. You've got a rate base number, which is coming from Page 16. And when you divide that adjusted net operating income by the rate base, you get the rate of return earned on the rate base.

Q. So is that the same calculation that was used for the ROR Index --

A. Yes. If you --

Q. -- in the testimony that Mr. Haynes provided?

A. So if you scroll through these -- these pages, or flip through these pages, I guess, you would see that. For example, I think it's Pages 7 and 8 that address Nucor specifically. So if you were looking at Nucor's Rate of Return Indexes, you would be able to go there to -- to see those.

Q. And so, Mr. Haynes, if I understand your testimony, you -- you had indicated that you thought there should be ROR, as you defined it then, as non-fuel total cost going to .80 was justified because all parties should share in your original case?

A. (Paul Haynes) In -- in the original case.

Q. Okay. And you -- the number that was actually used in your rebuttal testimony -- and I apologize -- on what was in your -- excuse me, your Stipulation of case, your Schedule -- I believe it's 1, 1 of 3, under Nucor column, Nucor Steel at Line 19, you show the present base non-fuel and then the proposed base non-fuel for a change of 483,083.

A. Yes. That is the total base non-fuel portion.

Q. That's the apples-to-apples by comparison to your earlier direct and rebuttal testimony?

A. Yes.

Q. All right. Now -- excuse me. And, in fact, that comes from Mr. Miller's Schedule 4, Page 1 of 2, the third block, which refers that that figure -- does that translate to a .83 index or .80 index?

A. Let -- let me introduce that, and then it would be right for Mr. Miller to -- to walk through that.

Q. Which line did you --

A. I -- I -- I -- Mr. Miller provides me with the third box on his Stipulation Schedule 4. So he provided to me that -- after the fully adjusted cost of service, before any non-fuel revenue increase associated with the Stipulation between Public Staff and Company, he provided to me, based on the accounting adjustments that were used to establish that cost basis for the Stipulation, that Nucor -- the Schedule NS class Rate of Return Index was .83.

Q. From --

A. What -- what I did was I then apportioned a revenue -- non-fuel revenue increase of $483,083 to Nucor such that they -- when you consider that non-fuel increase, the base fuel decrease of $438,000 for Nucor that their net -- they had a net total positive revenue increase. So I was -- I moved them from .83 to .80. I could not get them to .75 and satisfy the condition of the Stipulation.

Q. So what you're saying is -- is that .83 is what actually falls out from Mr. Miller's calculation using the non-base fuel cost -- total cost, excuse me -- non-base total cost -- non-fuel base total cost?

A. Yes.

Q. And then Nucor is going to be refunded excess fuel payments, right?

A. Yes. The -- the -- there will be a decrease in the base fuel factor, and when -- when -- when you say refund, there's -- there's what's called a Rider B for the Company. It's an experience modification factor that ultimately will true up all fuel revenues and fuel expenses in the annual fuel factor proceedings.

Q. And -- but -- but those are returning -- those are measuring on a pass-through basis as dollars paid and dollars returned; is that correct?

That's not a return on rate base dollars. You're just referring to dollars cash flow, without any return element being exchanged.

A. That's right. It's just a pass-through of expenses.

Q. So the justification for the increase in the non-base total index from the original .80 -- from .75 to .80 but that actually produced a .79 is to net the dollars that's going to be returned to Nucor because of what they actually paid due to their energy consumption?

A. I'm going to have -- maybe let Mr. Miller respond to that. I think we're getting the -- the supplemental series of accounting adjustments and fully adjusted cost of service that produced an index of ,79 and we're starting to cross that up with the Stipulation fully adjusted cost of service that has a different set of accounting adjustments. And -- and I think it might be appropriate if Mr. Miller explains what -- what he does in that fully adjusted cost of service and why those are different.

A. (Robert Miller) Certainly. So as -- as we discussed with the supplemental testimony, this sheet, Schedule 4 -- in both Supplemental and Stipulation Schedule 4s has multiple boxes on it. This Box 3, which is where you saw that .79 index on Supplemental, on rebuttal, the index indicated is actually a .83.

The reason for that change is that, as Mr. Haynes said, what I do is I take the accounting adjustments made by Mr. McLeod at the amounts that he's making them at the jurisdiction and I apply the allocation factors that he used to arrive at those accounting adjustments or the allocation of factors that are most appropriate, if it's something that's North Carolina-specific, and I carry those amounts down to the classes to see how each one of those would cause that adjustment so that the cost of service still reflects accurately the -- the overall effects of the customer classes.

So while in the supplemental schedule, the index might have been .79, the reason for that is that the adjustments made -- let me flip to that schedule here. You can see -- so the adjusted net operating income for Nucor under -- or for Schedule NS under the Stipulations -- or, sorry, the Supplemental Schedule 4 was \$6,007,532. The rate base was \$121,817,822, creating a rate of return of 4.9316.

The -- on the Stipulation filing, with the values and the adjustments that were included as part of that Stipulation, they had a different degree of effect on the Schedule NS class. And so the adjusted net operating income was \$6,682,923 and the rate base was one hundred twenty-one thousand four hundred twenty-three -- or, sorry, \$121,423,519, resulting in a rate of return of

5.5038 percent.

And so, as you noted, under the supplemental, Nucor had an index of .79, which makes sense. You know, they had a lower rate of return and so the index was also a little bit lower. On the Stipulation, Nucor's rate of return was higher, as was the overall ROR for the North Carolina jurisdiction. But that -- those factors resulted in Nucor having an index of .83.

Q. And that's your Box 3 and that's a non-fuel total cost number, correct?

A. That's Box 3. Fuel is not necessarily removed from the cost of service. If you look at my schedules, Schedule 3, Pages 15 -- or Page 15, you can see that Line 4 shows fuel revenues and Line 7 shows fuel expense. But in Column 3, which is where that Box 3 pulls from, those two are -- the difference between them is equal to the regulatory fee, which is part of the fuel recovery. But -- so they should offset completely.

Q. Well -- well, my point is that the 5.5038 shown as the ROR is -- is applied only to rate base dollars, isn't it? You're not proposing the Company earn a return on expense dollars.

A. No. The way that calculation works is that it is adjusted net operating income divided by rate base.

Q. So the result is -- the answer is you're only requesting a .83 for the return on the non-fuel total base rates in that Box 3?

A. I wouldn't say requesting, since these are basically just the results of performing that fully adjusted cost of service. But the calculation is such that that .83 is based upon the rate base and adjusted net operating income.

Q. So -- again, so, yes, it is not including fuel expense in that ROR Index?

A. The fuel expense is offset by -- or the fuel expense and the fuel revenue offsets, so there's no impact to the ROR.

Q. But in the column under Box 4, is there any fuel expense being included in the rate base for purposes of a return, any dollar at all?

A. In the rate base? Not that I'm aware of.

Q. And so -- and that number is adjusted, as I understand Mr. Haynes' testimony, because he was -- couldn't do it any further because the cap on the amount of we'll call it refund returned dollars from which Nucor had already paid fuel. That's what -- that's what prevented, in air quotes, Mr. Haynes' view from achieving the .75 he had originally proposed in rebuttal.

A. I'll defer to Mr. Haynes on it.
A. (Paul Haynes) Yes. That's correct.
Q. Okay. Thank you, Mr. Haynes and Mr. Miller.
CROSS-EXAMINATION BY MS. HICKS:
Q. Good morning, Mr. Haynes and Mr. Miller. My name is Warren Hicks. I represent CIGFUR.
And, Mr. Haynes, I have just a few questions for you. Those are going to be, to the best of my ability and based upon my intentions, compliant with CIGFUR's settlement with Dominion. I think that your attorneys will object if I get out of bounds. So we'll get started.
I would like to start by looking at your Stipulation Exhibit PBH-1, Schedule 1, Page 1. Let me know when you're there.
A. (Paul Haynes) Yes, I'm there.
Q. Okay. And I would like to look first at Section E, which is the total base revenue, and that's inclusive of non-fuel and base fuel, correct?
A. Yes.
Q. All right. And if you're looking at Line 27, that's showing the increase that's been first given to the total North Carolina jurisdiction and then, as you move across the columns, to the different customer classes, correct?

A. Yes. That's correct.

Q. All right. And the -- the total increase to the North Carolina jurisdiction is about six and a half million. Agree?

A. I agree.

Q. Okay. And if you move over one column, the residential class is getting a large increase of 5.8 or 9 million; is that correct?

A. Yes. That's correct.

Q. Okay. And if you move over two columns to the LGS class, you've assigned $682 to that class; is that correct?

A. Yes.

Q. And moving over one more column, you've assigned $9,573 to 6VP. Is that also correct?

A. Yes.

Q. All right. And if you'll recall back to yesterday when Mr. Xenopoulus was cross-examining you about the cost being allocated to Nucor, Class NS, I think you described that as very small. Does that sound correct?

A. Yes, in the context of their overall revenue.

Q. So looking at the costs that are being assigned to LGS and 6VP, would you agree that those are very, very small, very minimal? How would you describe that?

A. They're very small.

Q. Okay.

A. Minimal because I was trying to recognize that the Rate of Return Indexes -- and this is in the Stipulation with the Public Staff -- are above 1.20, well -- well beyond the -- what I call the parity index range and what Mr. Floyd terms as the band of reasonableness. Being -- being above 1.2 is beyond reasonable.

So I tried to conform with the Stipulation that everyone gets some level of increase, as you -- as we just discussed on Line 27, but as minimal an increase as possible considering the LGS and 6VP classes' rates. If -- if the Commission approves this level of rates, their indexes would still be high and they would be paying rates that would be above their responsibility for cost.

Q. And that's where I'm headed.

A. Okay.

Q. So -- and if you look at Line 28, that shows the percent change. And would you agree that the increase being assigned to the residential class is less than two percent above the North Carolina jurisdictional average?

A. Yes. That's correct.

Q. All right. And we were discussing the minimal increases that you've assigned to LGS and 6VP. And would you agree that those are supported by your testimony in this docket where you've acknowledged the value of high-load ratepayers taking service under those schedules?

A. Yes.

Q. Okay. So I'd like to move on and discuss Section 6 of the Public -- of your Stipulation -- the Company's Stipulation with the Public Staff, Page 10. Let me know when you're there.

A. Okay. I'm there.

Q. All right. And your Exhibit Stipulation PBH-1, Schedule 1 that's entitled "Summary of Final Rate Design" that we just discussed, would you agree that you prepared that final rate design based upon the guidelines that are laid out or the principles that are lied -- laid out in Page 10 of the Public Staff Stipulation and that's I through III and then also the provision that appears at the very end of that section?

A. Yes. That's -- those are the guidelines that I followed.

Q. Okay. And can you briefly summarize those guidelines?

A. Okay. And the -- the first guideline on Page 10 is that the company shall assign the approved revenue consistent with the principles of revenue apportionment described in Public Staff Witness Floyd's testimony.

The second is the parties agree that the company shall implement the rate design proposed by Company Witness Haynes in his direct testimony filed contemporaneously with the application in the docket and as adjusted by this Stipulation.

And then, finally, in meeting the provisions of those -- those two, I and II, in apportioning the approved revenue requirement to the customer classes, awareness and consideration shall be given to the Rate of Return Indexes for the LGS and 6VP classes being above 1.20 and an appropriate Rate of Return Index for the Schedule NS class.

Q. All right. And would you also agree that the Stipulation requires that all classes share in the total base rate increase which you discussed earlier today?

A. Yes.

Q. All right. So I would like to look at Company Stipulation Exhibit REM-1, Stipulation Schedule 4. It's two pages. And let me know when you're there.

A. Yes. We're -- we're here.

Q. All right. And if you look at the third block on Page 1, class rate of returns after all the rate-making adjustments before the revenue increase, and you look at the Rate of Return Indexes on the bottom line, Large General Service is showing a 1.32 and 6VP is showing a 1.22.

And in the Stipulation, when you refer to classes 6VP and LGS having Rate of Return Indexes above 1.20, is this what you're referring to?

A. Yes. This is the information that's referred to in the Stipulation.

Q. All right. And would you agree that -- and, ideally, every class would have a Rate of Return Index of one, but that's not feasible?

A. Correct. That -- that -- that is not feasible.

Q. And so you have a range of reasonableness?

A. Yes.

Q. And how does the Company define a reasonable Rate of Return Index?

A. I actually call it a parity index range, but, as I said, Mr. Floyd calls it band of reasonableness, so let's just call it a range of reasonableness. I think both Mr. Floyd and -- and the Company and my testimony believe that is .90 to 1.10 is -- is that range of reasonableness.

Q. And so if a rate class has a Rate of Return Index outside of that range of reasonableness, is their Rate of Return Index unreasonable?

A. I would say that the Rate of Return Index is -- is beyond what is considered reasonable by both the Company and the Public Staff.

Q. And I believe you touched on this earlier, but if a customer class has a Rate of Return Index that is above that range of reasonableness, so above 1.10, then that is an -- that indicates that they're paying more than their cost of service?

A. Yes. Their rates are -- are -- have been established at a point that places their recovery of costs from them, from those two classes, well above their allocated responsibility for cost.

Q. And would you also agree that that's a reflection that they are subsidizing other rate classes?

A. Yes.

Q. All right. And just for a second, going back to the Stipulation between Dominion and the Public Staff, Page 10, (iii), so Roman numeral three, it references that LGS and 6VP classes have Rate of Return Indexes above 1.20.

We've just discussed that the range of

reasonableness is .9 to 1.1. What is significant about 1.20?

A. I -- I think what's significant is, as -- as we've discussed and as indicated in -- in the fully adjusted cost of service, Box 3 on Mr. Miller's Stipulation Schedule 4, that the LGS and 6VP classes are above 1.20 at that point, before any increase is apportioned to them. And at 1.20, that is ten index points -- ten -- ten basis points above -- or let's say ten index points above the -- the range of reasonableness. And that's going to result in a much higher rate of return for that -- for those two classes, and, in turn -- and I know we've discussed the cost of service and the -- the work in this case is based upon a point in time, a test period.

In terms of the long term, you know, that would not be something that you would want to have in place for the long term for your large, high-load factor industrial class. And I talk in both my direct and rebuttal testimony about the importance of the industrial class in terms of the economic vitality of our communities in North Carolina, of the employment that they bring to those communities.

And if we -- if we have rates that are high for those classes, it's possible -- and -- and I can cite an example that I -- I mention in my testimony -- that industrial customers could start to look elsewhere perhaps because electricity is a high component of their cost structure and they may -- perhaps they have a -- multiple facilities and they have available capacity at a facility in another service territory that might have lower rates and they might decide to consolidate operations from a facility in our service territory and -- and move -- move those operations to a sister facility, taking the facility away from the service territory, our service territory, and, you know, causing employment reductions and other economic impacts for the communities we serve. So I don't think it is a -- a good -- good thing in the long term for these classes to have an index of 1.2.

Q. And, Mr. Haynes, would you agree that CIGFUR's members are indicative of high-load factor industrial customers that you've just described?

A. Yes.

Q. So I would like to move on to Page 2 of Company Stipulation Exhibit REM-1, Stipulation Schedule 4. And looking at the second block on that page, is it fair to say that that second block reflects the class rate of returns after all the ratemaking adjustments and after you've incorporated the -- the ratemaking -- the proposed ratemaking that we talked about in your schedule earlier, Exhibit PBH-1?

A. Yes, but it might be appropriate if Mr. Miller also responded to this question.

MS. HICKS: Is that okay with counsel?

MS. KELLS: Yes.

Q. Okay.

A. (Robert Miller) Would you mind just repeating the question? Sorry.

Q. So the second block on your -- on your exhibit, on the second page of that exhibit, that's indicative of the class rate of returns after all the ratemaking adjustments and after the total base rate increase, so fuel and non-fuel?

A. Yes. That's correct.

Q. Okay. And, Mr. Haynes, I'd just like you to look at the Rate of Return Indexes on that page. If you look at residential, it would appear that they have a .93 Rate of Return Index, which would be within the range of reasonableness as you just defined it, but would you agree that it is also below parity?

A. (Paul Haynes) Yes, it is within the reason -- range of reasonableness, but it is below 1.00, meaning it's -- rates that they're paying are below their responsibility for cost.

Q. And would you also agree that Large General Service is looking at a Rate of Return Index of 1.25?

A. Yes.

Q. And that is above the 1.20 number that we've been discussing?

A. Yes, it is.

Q. It's five basis points above, or index points above?

A. Yes. That's correct.

Q. Okay. And then 6VP is receiving a Rate of Return Index of 1.15; is that correct?

A. Yes.

Q. And you agree that that is outside the range of reasonableness that we've discussed?

A. Yes.

Q. Okay. And these Rate of Return Indexes are reflective of those very small increases that we were discussing earlier?

A. Yes.

Q. Okay. And so you agree that even with those very small increases, Schedule 6VP and LGS will be paying rates above cost?

A. Yes. They'll be paying rates above cost and beyond that range of reasonableness.

Q. All right. I would like to look at Table 1 on Page 25 of your direct testimony. Let me know when you're there.

A. Okay.

Q. All right. So I would like you to look at the bottom row on Table 1. And would you agree that -- well, first of all, Table 1 indicates the rate design that you proposed when this -- when this case was originally filed and the Rate of Return Indexes that were originally targeted; is that correct?

A. Yes.

Q. Okay. And, originally, the residential class was targeted with a Rate of Return Index of .97?

A. Yes.

Q. And you agree that that's below parity?

A. Yes.

Q. And it's higher than what they are currently being assigned pursuant to the settlement with the Public Staff?

A. Yes.

Q. All right. And moving across the table to the LGS column, originally, the LGS class was targeted with a

1.13 Rate of Return Index?

A. Yes.

Q. And that is well below the 1.25 Rate of Return Index that they're currently being assigned?

A. Yes.

Q. Still above cost, though, correct?

A. Still above cost. That's correct.

Q. And then moving over to the 6VP column, the 6VP class was originally targeted a Rate of Return Index of 1.03, which would put them inside the parity index range. Would you agree?

A. I agree.

Q. Okay. And, Mr. Haynes, can you appreciate that the 6VP and LGS classes view the Rate of Return Indexes that are demonstrated on Table 1 of your direct as being more equitable than what they've been assigned post settlement with the Public Staff?

MS. KELLS: I would object to the extent you're asking the witness to speculate about the LGS and 6VP classes, feelings about their proposed rates.

CHAIR MITCHELL: Can you restate the question?

MR. GRAY: Please pull the microphone.

Q. Mr. Haynes, in your opinion, are the Rate of

Return Indexes that were originally targeted on -- and are demonstrated on Table 1 of your direct more equitable to the LGS and 6VP classes than what is currently proposed post settlement with the Public Staff?

A. I -- I believe that the indexes in my Table 1 on direct are -- are more equitable. I -- I do want to point out that at that point in time, if you go up a couple of lines in -- from the bottom of my Table 1, I have a non-fuel revenue increase all charges, and you'll see there under the LGS class that -- that the non-fuel increase was $807,024 and the Stipulation non-fuel increase for the LGS class is $337,391, or about $480,000 less. And for the 6VP class, if you look at Table 1, the non-fuel increase was $296,603 and the Stipulation results in an increase of one hundred -- base non-fuel increase of $144,958.

So I believe, while the Rate of Return Indexes are not within the reasonable range coming out of this Stipulation, the overall -- the -- the base non-fuel revenue -- the -- the terms of the Stipulation result in a nice reduction in the increase in base non-fuel revenue from -- if you compare the going in filing in my Table 1 to the outcome of the Stipulation in my Stipulation Schedule 1.

The -- the revenue increase being a portion of

LGS and 6VP is significantly less. So I believe the Company and the Public Staff's efforts in coming together have resulted in, ultimately, a lower revenue increase than what the Company initially proposed to these two classes. But I do -- do agree that the ROR Indexes coming out of this are beyond the reasonable -- range of reasonableness.

Q. Mr. Haynes, do you agree that there are multiple components that go into arriving at just and reasonable rates during a general rate case?

A. Yes.

Q. And one of those components would be the revenue requirement?

A. Yes.

Q. And another one of those components would be cost allocation and rate design?

A. Yes.

Q. And do you understand that CIGFUR opposes sustaining higher class rate of returns as a result of a lower revenue requirement that benefits all the customer classes?

A. Yes.

Q. And, Mr. Haynes, would you agree that a goal of cost allocation and rate design is to move customer classes with ROR Indexes outside the reasonable range, toward a reasonable class Rate of Return Index to the maximum extent practicable without causing rate shock to other classes?

A. Yes.

Q. And would you also agree that when you're restricted by impacts to other classes, it may take several rate cases to move a class that has a high Rate of Return Index towards parity?

A. Yes. It -- it could.

Q. But would you aim to move that class closer to parity with each rate -- with each rate case?

A. Yes. That -- that should be the goal.

Q. So I'm going to reference an exhibit that was admitted yesterday. It's AGO McLeod Cross Exhibit 3. And there's a schedule in the back of that exhibit -- and that exhibit is the Stipulation from Dominion's last general rate case, E-22, Sub 532. And in that packet, there's Settlement Exhibit 3, Page 1 of 3.

MS. HICKS: And I had handed out additional copies of that earlier. Is there anyone who needs a copy of it? It has CIGFUR in red at the top.

Q. All right. Mr. Haynes, do you have a copy?

A. Yes.

Q. All right. If you go down to the third block on that page, would you agree that after adjustments for cost of service -- for the cost-of-service study that 6VP had a Rate of Return Index of 1.59?

A. Yes.

Q. And would you agree that, going down to the fourth block, after the revenue requirement was assigned to the customer classes, 6VP had a Rate of Return Index of 1.15?

A. Yes.

Q. And what -- remind me, what is the Rate of Return Index that's being assigned to 6VP in this case?

A. It's going to be in Mr. Miller's Schedule 4. It is 1.15.

Q. And, Mr. Haynes, to your recollection, was that settlement accepted by the Commission?

A. Yes.

Q. Mr. Haynes, do you understand that 6VP -- 6VP customers would like to see improvement in their parity index range in this rate case?

A. Yes.

Q. And, Mr. Haynes, absent the provision in the Stipulation that requires that all customer classes must share in the increase, is it possible to give a minimal base rate decrease to LGS and 6VP while complying with the other provisions in Section 6 of this Stipulation of settlement with the Public Staff?

A. I might need for you to say that again. If -- if -- let me say it the way I think I heard it.

You're asking me to not consider that last sentence in the -- the section about everyone sharing in the base revenue increase?

Q. That's correct.

A. If I set that aside, could the revenues for 6VP decrease such that other provisions related to Mr. Floyd's testimony and mine on principles, that they would be met?

Q. That's correct.

A. That's a hypothetical situation. I think that could be achieved. I think you could take -- if you -- if you didn't have that provision about everyone sharing in the base revenue increase, and she's asking me not to consider that, could you give the 6VP class a revenue -- base revenue reduction and all the other conditions of moving towards parity of no class having an increase more than two percent above the jurisdictional return, it's -- it's possible that could be achieved.

Q. Thank you, Mr. Haynes. I don't have any more questions.

CHAIR MITCHELL: Any additional cross-examination from the Panel?

MS. FORCE: Could I --

CHAIR MITCHELL: Okay. Ms. Force.

CROSS-EXAMINATION BY MS. FORCE:

Q. Sorry. I don't see the card. My name is Margaret Force with the Attorney General's Office, and I just have one question for you, Mr. Haynes.

It has to do with the basic customer charge under the settlement. Oh, excuse me. I have an exhibit that was provided to me in discovery that indicates that under the settlement, it's the Company's understanding that what is a present basic customer charge of $10.40 would go to $10.91.

Does that match your understanding?

A. (Paul Haynes) Yes. For the residential Schedule 1 --

Q. Exactly.

A. -- customers, yes.

Q. Thank you. That's my only question.

CHAIR MITCHELL: Redirect?

MS. KELLS: Yes, a bit.

REDIRECT EXAMINATION BY MS. KELLS:

Q. Mr. Haynes and Mr. Miller, yesterday, Mr.

Xenopoulus discussed with you whether the Company's use of the Summer-Winter Peak and Average Method was based on, you know, the Company's principles of cost allocation or was done to achieve a certain outcome.

Do you recall that exchange?

A. (Paul Haynes) Yes.

A. (Robert Miller) (Witness nods affirmatively.)

Q. Mr. Miller, I think we've also discussed your Rebuttal Table 2 on your -- in -- on Page 7 of your rebuttal testimony.

A. (Robert Miller) Yes. That's correct. I believe we did.

Q. Would you briefly summarize what the outcome for the Schedule NS would be under the alternative cost allocation methodologies presented in that table?

A. Certainly. As I discussed yesterday with -- with Mr. Xenopoulus, we prepared a fully adjusted cost of service using the various methods proposed by the CIGFUR and Nucor witnesses. So under those methodologies and 1CP SWPA 60 -- or the Summer-Winter Peak and Average 60 percent demand methodology and the Summer-Winter Peak and Average 50 percent demand methodology were the three proposed by the Nucor witnesses.

Under those, Nucor would receive a decrease under Summer-Winter CP -- or under the 1CP method, it would be a decrease of $13 million, roughly. Under the 60 percent demand method -- demand weighted Summer-Winter Peak and Average, they would receive a decrease of $2.7 million. And under the 50 percent demand methodology, they'd receive a decrease of $64,000.

Q. Thank you. And in the second column of the first section of that Table 2, where it shows the base rate non-fuel revenue increase or decrease for the residential class, what's the outcome under those alternative --

A. Certainly.

Q. -- methodologies?

A. Certainly. Under the 1CP methodology, residential would be recommended to set it at the same index that we filed in Supplemental A, $63 million increase. Under the 60 percent demand methodology, it would be a $24.6 million increase. And under the 50 percent demand methodology, it would be a $20.8 million increase. And that's compared to a $17 million increase as recommended on Company Supplemental Filing.

Q. Thank you.

A. Approximated on Company Supplemental Filing.

Q. And then Mr. Xenopoulus discussed with you yesterday, Mr. Haynes, the fact that Duke Energy Carolinas and Duke Energy Progress use a 1CP cost allocation methodology.

Do you recall that?

A. (Paul Haynes) Yes.

Q. And in the course of that discussion, you referenced a -- a discovery request that you'd answered in this case in which you'd stated that you knew that Duke Carolinas used a 1CP and you weren't aware that Duke Progress did, but that you had -- and you mentioned yesterday you've since become aware that Duke Progress also uses a 1CP.

Is that -- do you recall that discussion?

A. Yes.

Q. And is the -- would you agree that the reason you thought -- weren't aware that Progress uses a 1CP is that you were recollecting that in the past they'd used the Summer-Winter Peak and Average?

A. Yes.

Q. And in the time since you were asked those questions, did you clarify and do you understand that in the Duke Energy Progress's 2013 rate case was the first time in approximately 20 years that that company changed from using Summer-Winter Peak and Average to a 1CP methodology?

A. Yes. I believe that was -- I read a portion of the Commission's order in that proceeding that provided that information about cost allocation and past use of the Summer-Winter Peak and Average method in various rate proceedings over a 20-year period.

Q. And, in fact, it's -- is it your understanding that the Commission found Summer-Winter Peak and Average to be the appropriate cost allocation methodology for Duke Energy Progress -- at the time, CP&L -- in its previous four general rate case proceedings that's Docket Numbers E-2, Subs 461, 481, 526 and 537?

A. Yes.

MS. HICKS: In an abundance of caution, I'd ask that the Commission take judicial notice of its order in the Docket Number E-2, Sub 1023, DEP rate case.

CHAIR MITCHELL: Hearing no objection, we shall take judicial notice.

MS. HICKS: Thank you.

Q. Also on the topic of the Summer-Winter Peak and Average and the discussion you had yesterday about whether -- how -- for all the reasons that that is the appropriate method for Dominion to use, you were the cost allocation and rate design witness in the Company's 2016 rate case; is that correct?

A. Yes.

Q. And so you're familiar with the Commission's final order in that case?

A. Yes.

Q. And do you recall that in Finding of Fact 40, the Commission found that Dominion's continued use of the Summer-Winter Peak and Average method in this proceeding properly assigns production plant costs to all customer classes, including the Schedule NS class in recognition of its significant use of the Company's generation throughout the year?

A. Yes. I believe that was one of the Findings of Fact in the section on cost allocation rate design.

Q. And do you also recall from that case that the Commission concluded that it recognizes and affirms its prior determination in the Progress 2013 case that cost allocation does not lend itself to a one size fits all approach?

A. Yes.

Q. And would you agree with that conclusion of the Commission, that cost allocation does not lend itself to a one size fits all approach?

A. I do agree.

MS. KELLS: Okay. I'm going to pass out just one Redirect Exhibit, if I may. We took the liberty of going ahead and labeling this, if it's okay, as DENC Haynes Redirect Exhibit Number 1.

CHAIR MITCHELL: The exhibit shall be so marked.

(DENC Haynes Redirect Exhibit Number 1 marked for identification.)

MS. KELLS: Thank you.

Q. And while that's getting passed out, just to get us oriented, Mr. Haynes, you've discussed with counsel for Nucor and CIGFUR your Stipulation Schedule 1?

A. Yes.

Q. All right. And you've also had discussions about how in the Stipulation the Company has proposed a .80 Rate of Return Index for the NS class; is that right?

A. Yes.

Q. Can you -- so your Stipulation Schedule 1 shows -- can you describe for us what this exhibit is?

A. Okay. This is my DENC -- or this DENC Haynes Redirect Exhibit Number 1 is a summary final rate design similar to what I showed in my Stipulation Schedule 1. Sections A through G are -- are identical and present the same information.

I have added Sections H, I and J to show the impact in Section H of a matter that's -- we brought before the Commission in the fuel case and here to implement a Rider A-1, which is -- would take effect November 1, 2019, when interim rates in this case would begin to be -- to be billed to customers. And this Rider A-1 is a decrement rider and it's designed to -- to bridge the difference between the current Rider B, which is a positive charge, and recovering -- and under-recovery of fuel expenses from our last fuel case to a proposed Rider B in our current fuel case, which is significantly lower. And -- and the Company's proposing this based upon the -- the -- the anticipation of an over-recovery of fuel expenses in the second half of 2019. So this is actually going to be bringing forward the -- the effect of that -- that improvement in fuel cost recovery such that we can provide a further revenue reduction to customers to offset the non-fuel base rate increase and -- and -- beginning November 1.

And then I just have a section where I include non-fuel rider revenues, such as DSM cost recovery and renewable energy portfolio standard recovery to get to a bottom -- bottom line effect on -- in Section J of total revenue recovery reflective of base revenue Rider EDIT revenue and this proposed Rider A-1 change.

The overall impact for the North Carolina jurisdiction will be a reduction -- percentage reduction of 2.3674 percent. The residential class has a very small increase of .1754. The rest of the customer classes, except for lighting, have a decrease and then the lighting has a two -- two percent -- 2.05 percent increase.

Q. Thank you. And so just to be really clear, everything in this exhibit, all the way down through Section G, is exactly the same as what was in your Stipulation Schedule 1?

A. Yes.

Q. And then Sections H, I and J are what is different about this exhibit?

A. Yes.

Q. Okay. And then in Section I, just also to be clear, the non-fuel rider revenue from Dominion's riders DSM and RATS, you kept those values the same for present and proposed just because those cases have not been finalized? That's --

A. Yeah. Changes to those riders are pending in separate proceedings before the Commission.

Q. All right. Thank you. Also with regard to discussions you've had with counsel regarding the Rate of Return Index for Nucor and the industrial classes and the provision in the Public Staff Stipulation that all classes share in the increase, you're not working with the same revenue requirement at this point as you were in your direct or rebuttal cases, are you?

A. No. It's -- it's significantly lower.

Q. To put it really plainly, you don't have as many dollars to work with, do you?

A. Yes. That's correct.

Q. And finally, the requirement that is reflected in the provision in the Stipulation with the Public Staff that all classes share in the increase, you also discuss this in your testimony as a principle that the company tries to achieve?

A. Yes, from a base non-fuel --

Q. Right.

A. -- revenue perspective.

Q. Would you agree that, you know, in -- in this case -- for purposes of this case, that principle is sort of the priority principle among all of those that you've discussed?

A. Yes.

Q. Just as a matter of fairness?

A. Yes.

Q. And then you discussed with Ms. Hicks whether the Rate of Return Index for the industrial customers is more or less equitable under the stipulated proposal. Is that -- do you recall that?

A. We did have that discussion.

Q. Given the parameters of the Stipulation with the Public Staff and the amount of revenue requirement you're working with at this point in the case, would it -- is it your opinion that the Rate of Return Indexes you've determined for all classes are as equitable and reasonable as you can make them?

A. Yes. I think with the qualifier --

Q. Right.

A. -- that as equitable and reasonable as I can make them based upon the terms of the Stipulation.

Q. Thank you. That's all I have.

CHAIR MITCHELL: Questions from Commissioners? Mr. Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Gentlemen, good morning. First off, I have -- I have just a couple of questions, but first off, thank you for Late-Filed Exhibits 1 and 2. They've saved us some Q&A and some time this morning. I appreciate it.

Just a couple of questions based on some of the cross-examination. When -- when the Company is developing the Summer-Winter Peak and Average factors to allocate your production costs, for purposes of -- of the summer and winter peaks, do you treat the Nucor load as firm load?

A. (Paul Haynes) The -- the -- the -- the load that is -- yes. It's firm load in -- because we have an agreement that calls for them to curtail when -- when conditions are in -- when the system load conditions are peak, like on a cold winter morning or a hot summer afternoon.

We can -- our agreement provides that we can call for them to curtail their arc furnace load, and -- and it does drop down significantly --

Q. Right.

A. -- to a firm level.

Q. My question, though, is when you calculate the peak, you only use the firm level?

A. Correct.

Q. You do not use the interruptible maximum --

A. Right.

Q. -- up to the maximum?

A. We do not add back the maximum.

Q. Okay. So, again, the purpose of the question was just to be sure you're not really overallocating production costs to the North Carolina jurisdictional factor. You're not doing that because you're only computing your peak based upon the non-interruptible portion of the Nucor load.

A. That's correct.

Q. Got it. Thank you. I have to ask you some questions because I haven't been around here in any of the prior rate cases. So I need to connect some dots back to the past, and I understand you've -- you've been here before.

A. Yes.

Q. So as I understand it, the -- the Nucor Schedule NS goes back to 1999.

A. Yes.

Q. And it was -- was it -- is it -- was it intended to be a permanent rate schedule?

A. I think at the time -- and -- and we had a different agreement with them that provided sort of a -- what we call a system incremental cost basis for recovering revenue from them where we did not allocate them any production plant.

They paid marginal cost, effectively, and they did not get allocated any production plant, nor did they get the benefit of the system fuel factor and the average fuel cost based upon, you know, efficient dispatch of our system. About 2003, I believe what happened was those rates -- those system marginal cost rates became very volatile and the Company -- the customer, Nucor, approached the Company about revising the agreement and they expressed a desire to start getting the benefit of system average fuel cost to have some stability in their fuel rate, instead of paying a marginal cost rate.

We agreed to that, but with that agreement, to get the benefit of the system average fuel cost, Nucor -- at that point, we began allocating production plant costs to Nucor under the Summer-Winter Peak and Average method, because it's -- you should not get the benefit of system average fuel cost and efficient dispatch of our units if you're not paying some costs -- production costs, plant costs of those units.

Q. And -- and that revision goes back to 2003?

A. I believe it was 2003.

Q. If -- if it's not confidential information -- again, I'm trying to connect dots to the present. So I'll ask the question, and if it's confidential, you can tell me.

Does that agreement have a -- a fixed term?

A. The current agreement expires at the end of this year, I believe.

Q. Has it been -- are -- well, is it being renegotiated?

A. I'm -- I'm not the -- the contract administrator for that group, but that individual's a colleague. And I believe there have been some discussions with the customer, although I don't know what the status of those is. But the -- the date is approaching.

Q. If --

MS. KELLS: Commissioner, if I just -- my -- it's been renegotiated several times over the course of -- since it's been entered into in 2003. It comes up periodically.

Q. And -- and we're now in 2019 and it's being renegotiated again; is that correct?

A. Yes.

Q. So is the expectation -- the Company's expectation that -- that Schedule NS will continue, based upon some renegotiated agreement?

A. Yes, I think that is our expectation.

Q. If -- if negotiations are not successful and the parties are unable to reach agreement on a renewal or modification of that agreement, is it the Company's expectation that it would still continue to offer Schedule NS, if you can say?

A. If -- we -- there may be some term in the contract about some hundred and eighty day notification if we are to not offer it. So there -- there may be -- you know, working around that point in time, but, yes, at some point, if -- if it was not successfully renegotiated, then we would no longer offer that. So that -- Nucor would have to go on one of our other large industrial customer rates, either Schedule 6VP or Schedule 6L or Schedule 6P.

Q. Thank you. In -- in the 2016 rate case, the Company took the position, as I read the testimony -- I read back into some of the testimony -- that Schedule NS is a legacy subsidy to Nucor by other customer classes that needs to be addressed.

Do you agree with that position?

A. Yes.

Q. Is that the position of the Company today?

A. Well, it still needs to be addressed, but the Company believes in the 2016 case that the outcome of that case significantly addressed the -- the low rate of return index, which I think was about .43 in that case.

We gave -- we did give the Schedule NS class a significant non-fuel base rate increase in the last case. We -- we -- looks like it was in the neighborhood of about $5.3 million dollars per year. So we improved their index up to .75, so we think significant progress was made in that last rate case.

Q. Do you believe that the proposed rate for the NS class as -- resulting from the Stipulation with the Public Staff continues to make progress in the direction that the Company advocated in the 2016 proceeding?

A. Yes.

Q. You do -- you believe it continues to make progress in that direction?

A. Yes.

Q. All right. That's all I have. Thank you.

CHAIR MITCHELL: Additional questions from the Commission?

EXAMINATION BY CHAIR MITCHELL:

Q. I have one question. The -- I'll just address the panel and either one of y'all can answer it. But the -- the settlement agreement with CIGFUR references an -- a real-time pricing rate that is currently available but unsubscribed and indicates that the parties are going to work together to modify the rate.

Is that -- can -- can you -- can you speak to that and just let us know what the plan is and, you know, what -- what changes might be necessary to encourage participation?

A. (Paul Haynes) Yes, Chair Mitchell. What -- what happened in the last rate case, just a bit of history, there was a lot of talk about our industrial rates in that last case and doing something to improve our -- the rate schedules that we offer to help very large, high-load factor industrial customers. And we -- we did. We proposed a new Rate Schedule 6L that the Commission approved in that case. We've got, I think, four of our larger industrial customers on that. Some more may be considering it.

But the Commission did direct us -- and we -- we had some cross-examination and testimony at the hearing about this -- that maybe there's more that could be done to address helping these customers, because there's been a significant decline in industrial customers and usage in our service territory going back to the 1990s.

So we offered this new Schedule 6L, but we also discussed and the Commission directed us to investigate filing an RTP -- real-time pricing rate that might help high-load factor customers. So we did file what was called a 2RTP rates. I don't want to get too much into the details because they're rather complex, but, basically, these are hybrid rates that look at a portion of their load, or what's called a baseline, being served under our Rate Schedule 6L, which is very good for high-load factor customers, and an incremental load above a baseline being based upon real-time prices based upon the PJM market.

That got approved. We filed it. They've been in effect almost two years. We do not have any customers taking service under those rates. So -- and we've talked to customers about it and they're not willing to go on it. So the -- the Company and -- and CIGFUR in working out this agreement did agree to talk about these rate -- two rate schedules.

And if we can -- the Company and CIGFUR can agree on modifications to those rate schedules and if CIGFUR indicates that there is at least one customer that would go on such rate with the modifications that we agree to, then the Company would file that rate. And we feel like this is a reasonable thing to do to try to help industrial customers in the 6VP and LGS classes since no other customers would be harmed if we modify those rates because no one is on those rates today.

Q. Thank you. So -- but there is a plan to continue to work on the RTP offering?

A. Yes.

Q. Okay. Okay. Thank you.

CHAIR MITCHELL: Any additional questions from the Commission?

Questions on Commissioners' questions?

MS. KELLS: No.

MR. EASON: I just have two questions.

CHAIR MITCHELL: Mr. Eason.

RECROSS-EXAMINATION BY MR. EASON:

Q. Mr. Haynes, Commissioner Clodfelter asked you about the 2003 transition from the original form of the contract to the contract which provided a average cost of fuel and you focused on the stability of the pricing, specifically the energy component.

A. (Paul Haynes) Yes.

Q. It's true, isn't it, that the volatility you were talking about at that time period was such that Nucor could not place an order and determine what it would actually cost to produce it because the prices of its -- one of its major cost inputs of its arc furnace was so volatile that they couldn't -- couldn't quote without knowing whether they'd lose money or make money on the quote?

A. Mr. Eason, I -- I was not involved with the negotiation, but in hearing what happened at that point in time, that -- what you've described is my understanding of what the situation was.

Q. So there was a multi-million dollar plant that couldn't tell what they could produce profitably or not based on the contract format that existed?

A. Yes.

Q. And there was no discussion at the time with regard to future allocation or cost allocation methodologies but associated with simply having a mill that could actually know when to produce and when to, as you say, interrupt?

A. Yes. I -- I don't know if the idea or the situation with cost allocation of the system production plant to Nucor was discussed or not, but, generally, what you described is -- is correct.

Q. You -- you had a mill you couldn't run until --

A. Right.

Q. -- that issue got resolved. Then cost allocation became an issue.

A. Yes.

Q. Okay. And then with respect to Chairman Mitchell's questions and the -- that original contract was sometimes referred to, as opposed to a marginal cost, what they say, quote, a form of real-time pricing. Is that -- do you recall?

A. It may have been termed that, yes.

Q. You think Nucor's experience with -- with that tariff might have influenced any other industrials who have not opted to pursue that tariff?

A. It -- it may have.

Q. Okay. And since Nucor tried to obtain enough stability to quote so we could actually produce from the multi-million investment it made in a -- in a industrially deprived area of the state, they have received repeated increases in the amount of rate base that they have been assigned financial responsibility for based on this SWPA cost allocation?

A. They have.

Q. And so this discussion I had with you this morning, that's after you accept the -- I think you alluded to in response to Ms. Hicks approximately $10 million a year differential based on the allocations, disregarding whether we look at equity parity indexes, just the allocation?

A. Yeah. I'm not sure about the -- the 10 million a year. The -- in the last case, it was -- we took them from a .43 to a .75 index and it was about $5.3 million.

Q. I understand. That was one rate case.

A. One -- one rate case.

Q. I'm talking about since '03.

MS. KELLS: I'm going to object to the line of questioning as going beyond the scope of Commissioner Clodfelter's questions.

Q. Let me --

MR. EASON: No. I was referring to Mitchell.

Q. Let me just ask one thing. With respect --

MS. KELLS: I'm going to continue to object until --

MR. EASON: No. It's not about this. I'm changing the line.

MS. KELLS: Okay. Thank you.

MR. EASON: And it's about your question about load factors.

MS. KELLS: Okay.

Q. With regard to Nucor's interruptible, we talked about it as an interruptible. That was the basis of the proposed adjustment made in your rebuttal case.

Because -- can Nucor achieve a load factor matching some -- or other companies that do not have the --

MS. KELLS: I object. I'm sorry. How does this relate to the real-time pricing schedule?

MR. EASON: No. It's the load factor issue.

Q. Is Nucor a high load factor by comparison to, say, a 6VP?

MS. KELLS: I'm going to continue to object. Are you asking --

CHAIR MITCHELL: Mr. Eason --

MS. KELLS: -- questions on Chair Mitchell's questions?

CHAIR MITCHELL: My -- my questions to the witnesses had to do with the real-time pricing offering that was discussed in the CIGFUR settlement. So please make sure your questions relate to my question.

Q. The eligibility for the real-time pricing is associated with load factor, correct?

A. (Paul Haynes) No. The -- the concept behind the Commission's order for -- to us to file a real-time pricing rate was to try to help industrial customers with a high load factor and provide an additional tool beyond our Schedule 6L that got approved in the last case. So we filed these RTP rates and came up with a hybrid rate that blended Schedule 6L on a baseline level of load -- firm level, you might call it -- and having all incremental load above that be based on a real-time price, hourly price.

Q. And my only question is with respect to those load factors Nucor because it's interruptible doesn't achieve a load factor comparable to some of these other industrial customers.

A. Yeah. That -- that -- that's true. But if you looked at a portion of your load -- like, a firm portion that Commissioner Clodfelter and I discussed, around the clock, that has a very -- very high load factor, nearly a hundred percent.

Q. I agree. That's -- that's my point. It's the -- it's the interruptible versus the firm portion --

A. Correct.

Q. -- of the Nucor load.

A. Yes.

Q. That's all. Thank you.

CHAIR MITCHELL: We have one -- one additional question from Commissioner Brown-Bland.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Sorry, guys. Thought you were done. I'm sorry.

Has the parties dealt with the -- or created a mechanism to deal with changes caused by renegotiating the Nucor contract or would -- do you see seeking deferral after the rate case?

A. (Paul Haynes) I believe -- I believe the Company is, at this point, anticipating that Nucor and the company will agree to continue the current service arrangement. As -- as I said, there -- there -- there are colleagues at the Company that are negotiating that arrangement, and part of it will be, I'm sure, that the outcome or the progressive -- you know, as this case progresses toward a conclusion what the -- the outcome of this case might have on that contract.

But I think -- I think I can speak on behalf of the Company that we're anticipating trying to carry forward with that contract if Nucor agrees at this -- at this point in time. Once again, I'm not directly involved with the negotiation.

Q. Okay. Thank you.

CHAIR MITCHELL: Any questions on Commissioner Brown-Bland's question?

MS. KELLS: No. Would this be a good time to move all of the exhibits for Mr. Haynes and Mr. Miller into evidence?

CHAIR MITCHELL: Yes, please do so.

MS. KELLS: Okay. I so move.

CHAIR MITCHELL: Okay. Without objection, motion is allowed.

(DENC Haynes and Miller Exhibits were admitted into evidence.)

CHAIR MITCHELL: Any additional motions?

Okay. Gentlemen, you may step down. Thank you.

At this point, we will take a morning break and we'll come back on the record at 10:55. Let's go off the record, please.

(At this time, a recess was taken from 10:38 a.m. to 10:55 a.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please.

Dominion, please call your next witness.

MR. SNUKALS: Dominion Energy North Carolina now calls Mr. Jason E. Williams to the stand.

CHAIR MITCHELL: Good morning, Mr. Williams.

THE WITNESS: Good morning, Chair Mitchell.

JASON E. WILLIAMS,

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

DIRECT EXAMINATION BY MR. SNUKALS:

Q. Good morning. Would you please state your name and business address for the record?

A. Yes. My name is Jason E. Williams. Business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060.

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

A. I'm employed by Dominion Energy Services, Incorporated, and my capacity with reference to this case is as the Director of Environmental Services for the corporation.

Q. Did you cause to be prefiled in this docket on March 29th, 2019, 17 pages of direct testimony in question and answer form and an appendix consisting of two pages?

A. Yes, I did.

Q. Do you have any changes or corrections to that direct testimony?

A. No, I do not.

Q. If I were to ask you the same questions that appear in your direct testimony today, would your answers be the same?

A. Yes, they would.

MR. SNUKALS: Chair Mitchell, at this time, I would move that the prefiled direct testimony of Mr. Williams be copied into the record as if given orally from the stand.

CHAIR MITCHELL: Motion is allowed.

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

**DIRECT TESTIMONY
OF
JASON E. WILLIAMS
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562**

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

A. My name is Jason E. Williams, and my business address is 5000 Dominion Blvd, Glen Allen, Virginia 23060. My title is Director – Environmental Services for Dominion Energy Services, Inc., a subsidiary of Dominion Energy, Inc. ("Dominion Energy"), which provides services to Virginia Electric Power Company, doing business in North Carolina as Dominion Energy North Carolina (the "Company" or "DENC").

Q. Please describe your areas of responsibility within the Company.

A. In my current role, I oversee Dominion Energy's corporate waste, water and biology programs. In addition, I provide primary environmental support to the Power Generation and Power Delivery business groups.

Q. Mr. Williams, what is the purpose of your testimony in this case?

A. DENC is seeking recovery of deferred coal combustion residuals ("CCR" or "coal ash") expenditures incurred from July 1, 2016 through June 30, 2019, related to compliance with applicable regulatory requirements. First, my testimony will summarize the federal and state regulatory requirements that are driving the Company's coal ash expenditures. Second, I will provide an overview of the Company's history of coal-fired generation plants and will describe the CCR facilities at those locations. Finally, I will explain how DENC's actions and decisions to comply with the applicable regulatory requirements have been reasonable and prudent.

Company Witness Mark D. Mitchell will present the costs that the Company has incurred from July 1, 2016 through June 30, 2019.

Q. Mr. Williams, how is your testimony organized?

A. I have divided my testimony into the following sections:

Q. Please summarize your testimony.

A. DENC is subject to both federal and state regulatory requirements that mandate closure of its coal ash basins and other coal ash storage areas. The coal ash at DENC's sites are the byproduct of decades of efficient and reliable energy generation for its customers. Eight of the Company's facilities are subject to federal and state requirements for CCR unit closure. Those facilities are: Possum Point Power Station ("Possum Point"), Bremo Power Station ("Bremo"), Chesapeake Power Station ("Chesapeake"), and Chesterfield Power Station ("Chesterfield"), Clover Power Station ("Clover"), Mount Storm Power Station ("Mt. Storm"), Virginia City Hybrid Energy Center ("Virginia City"), and Yorktown Power Station ("Yorktown"). The Company is seeking recovery of its reasonable and prudent coal ash closure costs for activities it has undertaken to comply with both federal and state regulations.

I. FEDERAL AND STATE CCR REGULATIONS

Q. Why is DENC closing its CCR storage units?

A. On April 17, 2015, the Environmental Protection Agency ("EPA") published the CCR Rule, which regulates CCR landfills, existing ash ponds that still receive and manage CCR, and inactive ash ponds that do not receive, but still store, CCR. DENC currently operates inactive ash ponds, existing ash ponds, and CCR landfills that are subject to the CCR Rule at eight different facilities. This rule obligates DENC to retrofit or close all of its inactive and existing ash ponds over time, as well as perform required groundwater monitoring, corrective action, and post-closure care activities, as necessary.

Q. Specifically, what does the CCR Rule require?

A. This rule finalized national regulations to provide a comprehensive set of requirements for the disposal of CCRs from coal-fired power plants. The rule establishes technical requirements for CCR landfills and surface impoundments under subtitle D of the Resource Conservation and Recovery Act ("RCRA"), the nation's primary law for regulating solid waste. These regulations address groundwater monitoring, aquifer protection, wetlands protection, and stability requirements for coal ash surface impoundments. Additionally, the rule sets out recordkeeping and reporting requirements as well as the requirement for each facility to establish and post specific information to a publicly-accessible website. This final rule also supports the responsible recycling of CCR by distinguishing beneficial use from disposal. The VADEQ has also incorporated the CCR Final Rule into Virginia's solid waste management regulations as of December 2015. Virginia's adoption of the CCR Rule, which the EPA encouraged, requires DENC to seek a solid waste landfill permit from the VADEQ covering the closure and long term monitoring of the facilities subject to the CCR Rule.

Q. Does the CCR Rule mandate a specific closure option for ash ponds?

A. No. The CCR Rule provides essentially two options for closure. One closure method allowed by the CCR Rule is closure in place, which is also referred to interchangeably as cap-in-place. For closure in place, an ash basin is dewatered and an impervious cap is installed covering the ash basin. The second closure method allowed by the CCR Rule is removal, or excavation. If closure by removal is chosen, the ash pond is dewatered and the ash is placed in a lined, permitted CCR landfill or it may be beneficially reused under strict provisions for recycling.

Q. Did the EPA promulgate any additional rules that apply to the Company's coal-fired facilities?

A. Yes. On September 30, 2015, EPA finalized the Effluent Limitation Guidelines ("ELG") rules revising the regulations for the Steam Electric Power Generating category (40 CFR Part 423). The rule set new federal limits on multiple metals found in wastewater that can be discharged from power stations including a prohibition on discharges associated with bottom ash management systems.

Q. Did the Company develop closure plans to comply with the CCR Rule?

A. Yes. As required by the CCR Rule, DENC developed closure plans for each CCR pond and landfill. The deadline for completing these plans was October 17, 2016. DENC posted its plans on a public website and they are available at: www.dominionenergy.com/ccr.

Q. Has the Company's closure strategy changed since it published its CCR Rule closure plans?

A. Yes. Originally, the closure plans called for capping-in-place the coal ash impoundments at DENC's Bremo, Possum Point, Chesapeake, and Chesterfield power stations. However, with the passage of Virginia Senate Bill ("SB") 1355, the ash facilities at those locations are now required to be excavated. The closure plans for all the remaining coal ash facilities covered by the CCR Rule remain closure in place.

Q. Please describe the new Virginia legislation.

A. Virginia Governor Northam and a group of bipartisan legislative leaders reached a comprehensive agreement for closing the coal ash basins within the Chesapeake Bay Watershed, which include the ash basins at Bremo, Chesapeake, Chesterfield and Possum Point power stations.

SB 1355 prohibits the capping and closing in place of these existing ash ponds and, instead, mandates excavation and disposal of that ash in lined, permitted landfills. The legislation allows for either construction of onsite landfills, which must be fully lined and meet current landfill construction standards, or offsite landfilling, if necessary. DENC must also recycle or beneficiate approximately 25%, or nearly 7 million cubic yards, of the excavated coal ash, if it is economically feasible to do so.

Q. Are Virginia's closure requirements consistent with the CCR Rule?

A. Yes. Closure by removal is consistent with one of the closure options available under the state and federal CCR Rule. The CCR Rule contemplates that states may impose a specific closure option. In December 2016, federal legislation was enacted that created a framework for EPA-approved state CCR permit programs, which reinforced states' authority to establish closure requirements that are more restrictive than the federal CCR Rule. As such, the Virginia legislature has decided that excavation of all the ash facilities at Possum Point, Bremo, Chesterfield, and Chesapeake should be required. This action is similar to South Carolina's ash pond closure preferences as well as North Carolina's Coal Ash Management Act ("CAMA") legislation. Other utilities in states like South Carolina, Georgia, and Alabama are also excavating their ash basins.

Q. Are there any additional Virginia-specific regulations that apply to DENC's CCR units?

A. The Virginia General Assembly passed legislation in 2017 and 2018 that required the Company to conduct two studies to evaluate the closure of DENC's ash ponds. SB 1398 (2017) required an assessment of all of the Company's ash ponds in the Chesapeake Bay Watershed. The assessments included for each site:

- an evaluation of closure by removal with recycling or reuse;
- an evaluation of closure by removal with placement of ash in a landfill;
- an evaluation of closure in place;
- a demonstration of the long term safety of the CCR unit, related to extreme weather, flooding, hurricane or storm surge; and
- a description of the groundwater and surface water quality surrounding each ash pond and an evaluation of corrective active measures if needed.

Following the assessments conducted pursuant to SB 1398, the Virginia General Assembly then passed SB 807 in 2018. SB 807 required DENC to seek proposals to determine the feasibility and costs of recycling coal ash stored in CCR units at its Chesterfield, Possum Point, Chesapeake, and Bremo power stations. Both Senate Bills placed a moratorium on the issuance of any permit or approval by VADEQ to close any coal ash units within the Chesapeake Bay Watershed.

II. DENC'S COAL-FIRED GENERATION RESOURCES

Q. Please provide an overview of the Company's electric generation assets with CCR units.

A. For well over 100 years, the United States has relied on coal to provide inexpensive, reliable energy for its growing economy. DENC is proud to have been an integral part of this period in American history by providing low cost energy to its customers using coal as a fuel source. DENC operates coal-fired generation units at its Chesterfield, Virginia City, Mt. Storm, Clover, and Yorktown power stations. The Company's coal-fired generation units at its remaining facilities have been retired or converted to natural gas.

Q. How has the electric utility industry historically managed CCR?

A. CCR are generated as a byproduct of using coal as a fuel source. Efficiently and lawfully managing CCR was and continues to be a necessary component of providing coal-generated electricity. Over time, the utility industry has primarily used two disposal mechanisms for managing CCR: impoundments for sluiced CCR and landfills for dry CCR. When authorized by applicable regulations, the utility industry has also sought opportunities to find beneficial uses for CCR, including as an ingredient in concrete, or dry wall.

In 1988, the EPA submitted its Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants ("1988 Report"). The 1988 Report provided a snapshot of the electric utility industry's use of coal and management of CCR up to that point in history. The 1988 Report found that 80 percent of CCR in the industry was being treated and stored in surface impoundments or disposed of in landfills.

The CCR Rule provided another snapshot of the industry's coal ash management since 1988. The preamble to the CCR Rule noted that in 2012, approximately 40 percent of the CCR generated were beneficially used, with the remaining 60 percent treated and stored in CCR ash impoundments or landfills.

Q. Was the Company's management of CCR consistent with that of the industry?

A. Yes. The Company's ash handling practices have included a combination of management options over time, which have been consistent with the industry standard and regulatory requirements.

DENC has primarily utilized impoundments and landfills to manage its CCR. Additionally, the Company sought beneficial reuse projects to manage its CCR when available. Since the 1990s, DENC has recycled an annual average of 500,000 tons of CCR for beneficial reuse in the concrete and dry wall industries.

Below, I am providing a summary of the Company's coal ash management at each of its coal-fired generating facilities:

<u>Possum Point</u>: Possum Point was commissioned in 1948 as a coal-fired station. CCR management involved sluicing wet fly and wet bottom ash to five onsite ash ponds. These ponds were named Ash Ponds A, B, C, D, and E. Ponds A, B, and C are contiguous and were used as water treatment ponds to settle and manage low-volume wastewaters containing CCR from approximately 1955 to 1967. The original Pond D was constructed in the early 1960s before Ponds A, B, and C reached capacity and received CCR until 1971. The Company completed construction on a new Pond E in 1968.

In 1986, Pond E was nearing capacity, so the Company began construction on a new Pond D embankment to provide additional onsite storage space. The new Pond D was constructed with a 12" thick clay liner system. Ponds D and E continued to accept ash until the station's coal units were converted to natural gas in 2003.

Bremo: Bremo was commissioned in 1931 as a coal-fired power station. CCR management consisted of sluicing wet fly and bottom ash to three onsite ash ponds - the East, West, and North ponds. The East Ash Pond ("EAP") was constructed in multiple stages, beginning in the 1930s. The EAP stopped receiving CCR in the mid-1980s.

The West Ash Pond ("WAP") was constructed in the late 1970s. The North Ash Pond ("NAP") was constructed in two phases in 1982 and 1983. The NAP and WAP ponds continued to receive CCR until the station was converted to natural gas in 2014.

Chesterfield: Chesterfield was commissioned in 1944 as a coal-fired power station. Sluiced fly ash and bottom ash at Chesterfield was originally managed in the Lower Ash Pond ("LAP") and Upper Ash Pond ("UAP") where it was wet sluiced from the station. The LAP was constructed in two phases in 1964 and 1967-1968.

The UAP was constructed in 1985 to receive sluiced ash from the station and dredged ash from the LAP. The station ceased sluicing ash in 2017 when the facility converted to dry ash management.

Flue gas desulfurization ("FGD") solids have been generated at the site since 2008 as a byproduct from scrubbers used to clean air emissions. The FGD sludge is primarily composed of calcium sulfate or gypsum, which is beneficially reused as wallboard quality gypsum.

Chesapeake: Chesapeake was commissioned in 1953 as a coal-fired power station and continued to operate until December 31, 2014. All CCR from Chesapeake was originally managed in a single, onsite ash pond. Since about 1985, the station has stored fly ash in an onsite landfill permitted by VADEQ. Bottom ash has been sluiced to a separate bottom ash pond. Both the landfill and bottom ash pond are located within the footprint of the original ash pond. The coal-fired generation units at Chesapeake ceased operations on December 31, 2014, and have been decommissioned.

Virginia City: Virginia City was commissioned in 2012. All fly ash and bottom ash from the station is collected from the power station and moved by truck to the lined, onsite Curley Hollow CCR landfill. The landfill has a state of the art design including a synthetic liner and leachate collection/treatment systems.

Yorktown: Yorktown began operation in 1957. In 1985, DENC constructed a lined ash landfill on an adjacent parcel of property owned by DENC. Since that time, the dry fly ash and bottom ash has been loaded on trucks and hauled to the adjacent CCR landfill. The Yorktown CCR landfill is permitted by the VADEQ and is equipped with a bottom liner and leachate collection/treatment systems. The Company permanently closed over 60% of the landfill in 2017, and the remainder of the landfill will be permanently closed in 2019.

Clover: Clover was commissioned in 1995 as a coal-fired power station. The station has operated a dry fly and bottom ash system since it began to generate power. CCR has been taken to an onsite landfill for disposal, which is divided into three areas, or stages. Two landfill stages reached their maximum storage capacity in April 2003 and were subsequently closed in compliance with VADEQ regulations. Since 2003, dry fly ash and bottom ash has been stored in Stage III of the landfill. Clover also has two sedimentation basins used for settling wastewater solids, including FGD, prior to removal and disposal to the landfill. The water from these ponds is recirculated and FGD wastewater is not discharged. These ponds have been in place and operated since beginning operation in 1995.

Mt. Storm: Mt. Storm is located in Bismarck, West Virginia and is part of DENC's operating system. Mt. Storm was first commissioned in 1965 and continues to operate as a coal-fired power station. Dry fly ash and bottom ash are stored in the onsite lined Phase B landfill that is permitted by the West Virginia Department of Environmental Protection ("WVDEP"). The FGD sludge from Mt. Storm is beneficially reused in mine reclamation projects to neutralize mine acid runoff and in the manufacturing of Portland cement. Excess FDG sludge is disposed of in the onsite lined Phase A landfill.

III. DENC'S COMPLIANCE STRATEGY

Q. What closure option will the Company utilize to comply with federal and state regulations?

A. The Company plans to excavate its CCR units at its Possum Point, Bremo, Chesapeake, and Chesterfield stations. The Company intends to close in place its CCR units at its Clover, Mt. Storm, Virginia City, and Yorktown stations. The closure strategy for all of the Company's sites will comply with federal and state regulatory requirements.

Q. What actions has the Company taken since July 1, 2016, at each of its coal-fired generation facilities to comply with federal and state regulatory requirements?

A. Possum Point: The CCR Rule included provisions for "inactive" ash ponds that no longer received CCR after October 14, 2015. Ash ponds meeting the definition of "inactive" were recommended to close within three years or otherwise be subject to long-term monitoring and other costly provisions of the CCR Rule. DENC's ash ponds at Possum Point qualified as "inactive" under the CCR Rule. Accordingly, DENC proceeded expeditiously to close the inactive ponds at Possum Point by consolidating Ponds A, B, C, and E into Pond D - the largest pond at this site, which is also the furthest from waterways and the only pond at Possum Point with a liner. In 2018, DENC completed the excavation of ash from Ponds A, B, C, and E. DENC could not proceed further with closing Pond D because of the moratoriums created by SB 1398 and SB 807 that were passed in 2017 and 2018, respectively.

Bremo: The EAP and WAP at Bremo qualify as "inactive" ash ponds under the CCR Rule. As such, DENC proceeded expeditiously to close the inactive ponds at Bremo by consolidating the EAP and WAP into the NAP - the largest pond and the pond located furthest from waterways. Since April 20, 2015, ash from the East and West Ponds was excavated and consolidated in the North Pond. The consolidation activities are expected to continue through March 2019. DENC could not proceed further with closing the NAP because of the moratoriums created by SB 1398 and SB 807 that were passed in 2017 and 2018, respectively.

Chesterfield: As discussed previously in my testimony, Chesterfield operated two onsite ash ponds, the LAP and UAP. The CCR Rule requires that DENC close both ponds. The Company continues to operate Chesterfield as a coal-fired station. To comply with the CCR and the EPA's ELG Rules, Chesterfield underwent a number of wastewater and environmental improvements in 2017 to transition from wet sluicing coal ash to a dry ash management system. In order to manage the dry coal ash, DENC constructed an onsite, permitted landfill. The onsite landfill has been receiving dry ash since 2017. The Company has begun the process of closing the LAP and UAP pursuant to federal and state requirements.

Chesapeake: On November 13, 2018, DENC signed a Memorandum of Agreement ("MOA") with the Commonwealth of Virginia pursuant to which the Company agrees to groundwater monitoring and closure steps for coal ash at the facility consistent with the standards imposed by CCR Rule regulations.

The bottom ash pond is the only portion of the Chesapeake ash complex subject to the CCR Rule. However, this pond was constructed on top of the historic ash pond without a liner system. The adjacent landfill (also constructed on top of the historic ash pond) is subject to a VADEQ solid waste permit that requires groundwater monitoring of the entire ash complex. Therefore, although the historical pond and landfill are not subject to the CCR Rule, there is no way to distinguish groundwater from the bottom ash pond from that which is in contact with the historic ash pond. As such, the MOA was agreed to in order to ensure that the closure and monitoring of the historic ash pond and adjacent landfill will be consistent with the CCR Rule. All three of the ash facilities (original ash pond, landfill, and bottom ash pond) are slated for closure once necessary permits are obtained. Only minor closure activities have occurred within the Chesapeake ash facility. Between October 16, 2017 and March 9, 2018, a small portion of the bottom ash pond was removed for recycling. However, with the passage of SB 807 all further closure options were halted until such time as a path forward was directed by the Virginia General Assembly.

<u>Virginia Center:</u> Beginning in May 2016, DENC began installing wells and monitoring groundwater at Virginia Center to comply with the CCR Rule. DENC is required to monitor these wells semi-annually. DENC has continued to maintain compliance with its state permits and CCR Rule requirements related to its CCR units at the site.

<u>Clover:</u> As discussed earlier in my testimony, DENC historically operated two lined FGD settlement basins at Clover. Under the CCR Rule, DENC was required to close both FGD basins. CCR have been removed from the FGD basins, and they are now being retrofitted with a CCR Rule compliant liner. DENC has continued to maintain compliance with its state permits and other CCR Rule requirements related to its CCR units at the site. The removal of the first sedimentation basin began in 2017, and its replacement meeting the requirements of the CCR Rule was placed into service in 2018. The second sedimentation basin has also been removed and construction is scheduled to be completed by June 2019.

<u>Mt. Storm:</u> As stated previously in my testimony, the Mt. Storm station historically managed ash contact water from the ash loading area and bottom ash hydro-bins were directed to five small low volume waste treatment ponds (Pyrite Pond and Ponds A, B, C, and D). These ponds did not meet the liner standards of the CCR Rule but were needed for continued operation of the station. Therefore, the five original ponds were closed by removal and disposed in the onsite Phase B landfill. The station then constructed a new pyrite pond and two low-volume wastewater treatment ponds in the location of the former ponds. The onsite landfills (Phase A and B landfills) and their liners meet the definition of an active landfill and, as such, can continue to operate. The closure of these ponds and construction of the new ponds meeting the requirements of the CCR Rule began in early 2016. The majority of the removal and construction was completed in 2018. Construction of the

final pond's concrete liner will be completed in spring 2019. DENC has continued to maintain compliance with its state permits and CCR Rule requirements related to its CCR units at the site.

Q. Have the new Virginia closure requirements impacted the cost of closing the Company's coal ash facilities?

A. The Virginia legislation has not impacted the costs that the Company is requesting in this proceeding. When compared to closing all ponds in place, the Virginia legislation requirements will result in an increase of the cost of closure. The Virginia closure requirements allow multiple options for removal to onsite or offsite landfills as well as establishing a reasonable recycling target to limit that increase. In addition, closure in place comes with the uncertainty of future corrective action for groundwater. The Virginia legislation removes this uncertainty by establishing removal as the only closure method.

Q. Have the Company's actions to close its ash facilities been reasonable and prudent?

A. Yes. The Company is closing its coal ash facilities in accordance with state and federal requirements.

Q. Does this conclude your testimony?

A. Yes.

BACKGROUND AND QUALIFICATIONS OF JASON E. WILLIAMS

In his current role, Mr. Williams oversees Dominion Energy's corporate waste, water and biology programs. In addition, he provides primary environmental support to the Power Generation and Power Delivery business groups. During his time with DENC, he has served in a leadership role for the Company's coal ash pond closure projects. Throughout his career, he have amassed 18 years of experience with landfill permitting, groundwater and soil remediation, and overall environmental regulatory compliance.

Before joining DENC, Mr. Williams worked as an environmental manager at Waste Management Inc., North America's largest waste company, where he was responsible for environmental permitting and compliance for 13 landfills located in Virginia, Maryland, Delaware, and West Virginia as well as over 30 trucking and transfer facilities located throughout the mid-Atlantic. While serving as a project manager, and later as supervisor for the U.S. Navy, he was responsible for the management and oversight of all east coast Marine Corps remediation projects including coal ash landfills, debris landfills, and many petroleum or chemical release sites. During his time with the Virginia Department of Environmental Quality ("VADEQ"), he served as the solid waste permitting coordinator responsible for establishing the permitting standards for landfills including ash and industrial landfills. In addition to this role, he also lead VADEQ's revision of the Virginia coal combustion residual regulations, which governed the use of coal ash as structural fill prior to the establishment of the CCR Rule.

Mr. Williams is a licensed Professional Geologist and earned a Bachelor of Science degree in geology from Radford University in 2001. Since that time, he has completed graduate courses at Old Dominion University in pursuit of a master's degree in environmental engineering.

Q. Mr. Williams, do you have a summary of your direct testimony?

A. Yes, I do.

Q. Would you please now present your summary for the Commission?

A. Good morning, Chair Mitchell and Commissioners. I am Jason Williams, former Director, Environmental Services for Dominion Energy Services. Dominion Energy Services is a subsidiary of Dominion Energy, Incorporated, and provides services to Dominion Energy North Carolina. In July of this year, I transitioned to a new role as Director, Learning Development and Communications.

In this case, DENC is seeking recovery of deferred coal ash combustion residuals, or CCR, expenditures incurred from July 1, 2016, through June 30th, 2019. My direct testimony summarizes the federal and state regulatory requirements that are driving the Company's coal ash expenditures. I also provide an overview of the Company's history of coal-fired generation plants and will describe the CCR facilities at those locations. I also explain how DENC's actions and decisions to comply with the applicable regulatory requirements have been reasonable and prudent.

DENC is subject to both federal and state regulatory requirements that mandate closure of its coal ash basins and other coal ash storage areas. The EPA's CCR Rule, which was published in April 2015, regulates CCR landfills, existing ash ponds that still receive and manage CCR and inactive ash ponds that do not receive but still store CCR.

The rule requires the Company to retrofit or close all of its inactive and existing ash ponds over time and to perform required groundwater monitoring, corrective action and post-closure care activities, as necessary. Eight of the Company's facilities are subject to the CCR rule: Possum Point, Bremo, Chesapeake, Chesterfield, Clover, Mount Storm, Virginia City Hybrid Center, otherwise known VCHEC, and Yorktown.

Additionally, in September 2015, EPA finalized its Effluent Limitation Guidelines, or ELG rules, which set new federal limits on multiple metals found in waste water that can be discharged from power stations, including a prohibition on discharge associated with bottom ash management systems.

On the state level, earlier this year, Virginia Governor Northam and a group of bipartisan legislative leaders reached a comprehensive agreement for closing the ash basins -- I'm sorry, the coal ash basins within the Chesapeake Bay Watershed, which include the ash basins at the Company's Bremo, Chesapeake, Chesterfield and Possum Point stations.

Senate Bill 1355 prohibits the capping and closing in place of these existing ash ponds and instead mandates excavation and either recycling of the ash or disposal of that ash in a lined, permitted landfill. Under the legislation, 25 percent of the ash must be recycled.

My direct testimony presents additional Virginia-specific regulations that apply to the Company's CCR units. Prior to the Virginia legislation, the Company's plans for compliance with the CCR Rule originally called for capping-in-place the coal ash impoundments at its facilities located within the Chesapeake Bay Watershed. Our closure plans for the remaining ash facilities covered by the CCR Rule continue to call for closure in place.

My testimony provides an overview of the Company's electric generation assets with CCR units and discusses how the electric utility industry has historically managed CCR. I explain how the Company's management of CCR has been consistent with industrywide practice. I present the actions DENC has taken since July 1, 2016, at each of its coal-fired generation facilities to comply with the federal and state requirements. Finally, I clarify that the new Virginia legislation has not impacted the costs that the

Company is requesting to recover in this proceeding.

The coal ash at the Company's sites are the byproduct of decades of efficient and reliable energy generation for its customers. Eight of the Company's facilities are subject to the federal and state requirements for CCR unit closure. The Company is seeking recovery of its reasonable and prudent coal ash closure costs for activities it has undertaken to comply with both federal and state regulations.

This concludes my summary. Thank you.

MR. SNUKALS: Mr. Williams is now available for cross-examination.

MS. CUMMINGS: Public Staff has no questions.

MS. HICKS: No questions.

MR. EASON: No questions.

CHAIR MITCHELL: Questions by the Commission? Commissioner Clodfelter?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Williams, good morning.

A. Good morning.

Q. Yesterday, when Mr. Mitchell was up, I was asking him some questions about Late-Filed Exhibits Number 4 and 5.

Were you present when I asked him those questions?

A. No, sir. I was not.

Q. You were not. Do you have any familiarity with those exhibits that the Company filed just before the hearing, Exhibits 4 and 5?

A. I -- I do have awareness of those exhibits.

Q. Do you have access to those?

A. I don't think I have those right here with me. You're referencing the two charts?

Q. One was Exhibit -- Late-Filed Exhibit -- actually, they're 5 and 6. They respond to Questions 4 and 5, but the exhibit numbers are 5 and 6.

Late-Filed Exhibit 5 is a summary by task of the activities conducted between 2016 and this rate case for which the Company's seeking recovery. And then Exhibit -- Late-Filed Exhibit 6 relates to the Chesapeake Energy Center and the Yorktown regulatory assets.

A. Yes, sir.

Q. You -- do you have those now?

A. I -- I have the -- the first one and we are trying to track down the --

Q. Okay.

A. -- the copy of the second one.

Q. Again, the second one I used with Mr. Mitchell only for purposes of illustrating my question.

A. Okay.

Q. And -- and really, the gist of the question, when your counsel's able to get the exhibit to you, is whether or not it's possible to get the level of detail that is shown on Late-Filed Exhibit 6 -- to get the same level of detail with respect to the information shown on Late-Filed Exhibit 5. And -- and I was -- I think I was told that you might be able to help me with that question.

A. Well, I do -- I do know this. In response to that request yesterday, we do have staff right now adding granularity to the exhibit that you're -- that you're mentioning. So that is ongoing today, and I believe the plan is to provide that later today.

MS. GRIGG: Commissioner Clodfelter, I can address that, if I may.

COMMISSIONER CLODFELTER: That's fine, if it saves us time.

MS. GRIGG: We -- yes, sir. We plan to provide that to the Commission by Wednesday morning, tomorrow morning.

COMMISSIONER CLODFELTER: All right. That's fine. Let's -- let me just postpone any questions. I think Mr. Williams may be back on redirect or on rebuttal.

MR. SNUKALS: You are correct.

COMMISSIONER CLODFELTER: I probably should just wait and -- and we'll deal with it then.

Q. Mr. Williams, I'm going to work from your direct testimony. Do you have that available to you?

A. I've got my rebuttal with me. Direct -- yeah, I -- I've only got my rebuttal with me.

MS. GRIGG: I'll get it to him.

THE WITNESS: Thank you.

A. Yes, sir.

Q. Got it? Okay. I'm really going to be working from the information that starts on -- on Page 9. And I just have a series of questions about several of the plants and will start with Possum Point on Page 9.

My understanding of -- of the Company's -- of your testimony and the other information submitted by the Company in prefiled testimony is that the ponds -- the impoundments at -- at Possum Point A, B, C and E have now been consolidated into Pond D. Is that correct?

A. Yes, sir. That is correct.

Q. So -- so at Possum Point, the original Ponds A, B and C, I think your testimony says, were operated until -- accepted waste ash until about 1967; is that correct?

A. That is correct. A, B, C was until 1967.

Q. And -- and when were they consolidated? When were the contents of those three impoundments consolidated into Impoundment D? When did that occur?

A. So that would have occurred between 2016 and completing in 2019.

Q. So between 1967 and 2016, what -- what was the status of those three impoundments: A, B and C?

A. Those were in an inactive configuration. So they were covered with vegetation, largely with soil in -- in most areas, and -- and were essentially in an inactive state. There was no ash sluiced to those ponds during that time period.

Q. That -- that -- that's great. That -- because -- thank you for that, because that's taking me really to the heart of the question. Is when they became inactive --

A. Uh-huh (yes).

Q. -- what I really want to explore with you is what actions did the Company take at the point when it stopped placing new ash in those ponds. What did it do?

A. So the --

Q. In 1967.

A. In -- in 1967, when the new pond was constructed, which was the original Pond D, sluicing was redirected to that pond. A, B, C at that time was -- you know, was -- was put into an inactive state. It was covered partially with soil, allowed to revegetate and was left in that state from that time on.

Q. Was -- was the water -- were the ponds dewatered?

A. The -- the -- the -- the ponds were slowly dewatered over time, not in an intentional method or pumped or anything of that nature.

Q. Through --

A. They were left in a static state.

Q. Through natural attenuation, evaporation and migration of the water into the ground?

A. Through -- through -- through natural attenuation. Sure. Yes, sir.

Q. And -- and were any steps taken to control additional water coming into the ponds from storm water or from rainfall? Was anything done at that point to -- to stabilize the situation with the water in the ponds?

A. So there were, you know, vegetation that was, you know, spread over top of the pond. So that would have limited that. Keep in mind that in 1967, when it closed, there were no capping or closure standards applicable to those ponds, if you're -- if you're referencing some sort of a cap.

Q. Well, there had to have been some sort of soil covering if there was going to be vegetation or my understanding of how plants work is incorrect.

A. Yeah. There -- there certainly would have been --

Q. There had to be some sort of soil covering, right?

A. There would have been soil, but there was not a specification or a regulatory requirement on what that would look like at that time.

Q. Well, that's fine. I'm not interested in the regulations.

A. Sure.

Q. I'm interested in what the Company actually did.

A. Understood.

Q. Okay. So -- so what did the Company do to cover the ash?

A. I -- they -- they would have added soil on top of it and then vegetation spread as it went to -- to cover the entire top of it, or majority of it. There was one small area that was not.

Q. And were there any -- was there any sort of monitoring facilities installed either for groundwater or for the contents of the impoundment itself to monitor what was happening inside the -- the covered pond?

A. No. There -- there were none at that time.

Q. Not at that time?

A. There was no requirement to do that.

Q. Okay. Why did the Company -- why did the Company cover the pond and -- and plant it with vegetation? What was the source --

A. Well, most -- I'm sorry.

Q. What was the source of that decision?

A. Yeah. Most of the vegetation was just through natural migration and spreading. So the soil covering would have been just to facilitate access into that area. But it certainly wasn't what you would picture in modern days as engineer cover or anything of that nature.

Q. Was -- is it your understanding that that was standard industry practice at the time for an inactive surface impoundment, was to --

A. Yes.

Q. -- cover it with soil?

A. To cover it with soil or, in some cases, it was left to just attenuate as it naturally was open.

Q. In some cases. What would differentiate between the cases where there was a soil covering placed on it and the cases where it was just left to attenuate, as you put it?

A. It -- it just would have been specific to the particular operations at that site or need to access that area.

Q. Well, what at Possum Point caused the decision to be made that you needed to put soil covering over Impoundments A, B and C?

A. So, again, I -- I just want to clarify, because I don't want to -- to mislead. The -- the entire impoundment was not covered. A large portion of it was -- was covered during the inactive status and the vegetation spread. And -- and although there may not have been soil everywhere, as the historic photos show, there was significant vegetation even in areas that didn't have soil that -- that -- that was covered.

So it would have, again, just been it was put into an inactive state. There was a determination that portions of it would receive some level of soil, but, you know, that would have been for access purposes, not necessarily for any sort of cover standard.

Q. For access purposes. Can you elaborate on what that means?

A. There are a number of transmission lines that run directly through the pond. And so there would have been a need to retain access to those tower structures for maintenance and repairs. So there's transmission easements that -- that run -- that ultimately supply the -- the -- the yard at the station.

Q. So if I understand you correctly, not all of the surface area of Impoundments A, B and C was covered. Only some of it was covered with soil.

A. Correct.

Q. And -- and the parts that were covered with soil were the parts where you needed access only.

A. Is -- yes. Primarily, those were the -- were the areas, the access to get into the area. The rest of it naturally revegetated on its own.

Q. And -- and the vegetation was natural regrowth of plants that seeded themselves, not -- not -- they weren't intentionally planted by the company?

A. Yes. That's correct.

Q. Okay. Now, Pond E at Possum Point operated -- or received ash up until about 2003; is that correct?

A. Yes. That is correct.

Q. And -- and at the time it stopped receiving ash, what -- what did the Company do with respect to that impoundment? What actions did it take?

A. So that impoundment remained in its existing status. There were no actions taken at that particular site. That site also continued to manage other waste waters from the station that came from the metals pond or from other -- other low-volume waste -- waste waters.

Q. Did it continue to receive those other low-volume wastes after 2003?

A. It did. It did for a short amount of time, yes.

Q. Until when?

A. It would have been at the time that we began the removal of Pond E and excavation in that area.

Q. And that was in, roughly, 2016 when you --

A. Yes.

Q. -- started the removal?

So -- so when Pond E stopped receiving ash waste, did the Company take any steps to dewater the pond?

A. We did not at the time that it -- that it ceased operation --

Q. Did -- did --

A. -- as a sluicing pond.

Q. Did the Company take any steps to prevent the intrusion of additional storm water or groundwater into the pond at that point?

A. No. That pond was still open, as it had been when it operated, again, because there were waste water flows continuing to go to that pond. So it would have been, you know, counterproductive to do that.

Q. And so I take it also the pond was not covered with soil?

A. No, sir.

Q. And was any monitoring installed at the pond at the time it was closed?

A. Yes. There was monitoring at -- at Pond Echo in those monitoring wells around it at that time, in 2003.

Q. When -- when were those wells installed?

A. Let me just grab an exhibit from my -- let's see. For Possum Point, 1990; December 5th of 1990 is when monitoring wells were first installed at Pond E, Echo.

Q. And they were installed at Pond E, but not at A, B or C at that time?

A. This is correct.

Q. Why were they installed at Pond E in 1990?

A. So Pond E in 1990, it was a requirement under the VPDES or what Virginia calls their NPDES permits under the Clean Water Act, and there was a requirement for groundwater monitoring added into the permit.

There was not a similar requirement at A, B, C because A, B, C was no longer discharging, was no longer a regulated outfall, as it had closed in 1960, or ceased receiving CCRs in 1967.

Q. And that was the sole reason for the differentiation, was that Pond E was continuing to receive

additional waste streams?
A. Yes. It was -- continued to regulate as a VPDES permitted outfall.
Q. At what point were -- were the contents of -- of Impoundments A, B and C and E relocated to -- to Pond D?
A. So I -- I believe I answered that as started in 2016 through 2019.
Q. You did and I had forgotten the answer, which is why I needed to ask the question again. So thank you for that.
Now, A, B and C were not lined impoundments originally, were they?
A. That is correct. There was no liner. Correct.
Q. But D -- D was?
A. D was constructed with a liner when D was reconstructed.
Q. When it was reconstructed. It did not have an original liner?
A. No. The original pond did not have a liner.
Q. And at the time that it was reconstructed, that was in, what, 1986?
A. Yes.
Q. And what -- why was the decision made to install a liner in 1986?

A. So the -- the Company had placed oil ash into the corner of Pond Echo. That was not sluiced. It was -- it was trucked over. And that resulted in localized groundwater exceedances that ultimately led to a special order with the state, an agreement to, one, remove that oil ash and then to basically -- as we were running out of space, we needed a new Pond D anyway -- was to increase the height of the existing dam and then to install a one-foot clay liner in addition to areas where there was already existing clay and a slurry wall around what was the original Pond D.

And all of that was required to ensure that those concentrations would attenuate from that former placement of oil ash in Pond Echo.

Q. At the time that was done, were all the exceedances within the compliance boundary?

A. Yes. The --

Q. There were none outside the --

A. -- the inside --

Q. There were none outside the permit compliance boundary?

A. Correct.

Q. Help -- help me. What is oil ash? That's a new one for me.

A. So just from the combustion of oil to generate power. So as you'll find with many of our coal units in the early 1970s, with the Clean Air Act being passed, we converted over to oil and then went back to coal, unfortunately, as a result of the oil embargo in the mid-'70s. And so during that time, that oil ash was taken there.

Also in the '70s -- late '70s, we built Unit 5 at Possum Point, which is a 800 megawatt heavy oil-fired unit. And so that ash for a period of time was taken there. But then as a result of the special order and -- and the impacts associated, as the oil ash has a much different composition than that of coal ash, the oil ash from -- from that point on was -- was taken off site versus the coal ash continued to be managed as sluicing.

Q. Okay. Thank you.

A. Uh-huh (yes).

Q. When did Possum Point cease to operate?

A. Possum Point still operates today, the entire station. Units 3 and 4 were retired in 2019.

Q. The -- the coal-fired units were retired in 2019?

A. The -- the units were retired. They were converted from coal to natural gas in 2003.

Q. In 2003, at the same time that the impoundments were consolidated?

A. No. The -- the -- so in 2003, the Company switched from oil -- I'm sorry, from coal to natural gas on Units 3 and 4. So at that time, there was no more coal ash to sluice. And so the sluicing ended in 2003, but the consolidation did not begin until, as I stated earlier, 2016 --

Q. Thank you.

A. -- or 2015.

Q. I -- I apologize for wasting your time.

A. No, sir.

Q. When I meant closed, I should have said ceased operating as coal-fired generating units.

A. Yes, sir.

Q. When I'm talking about ceasing operation, I'm really focused on the operation of the coal-fired generating units, and I apologize for not being clear on my question.

A. Understood. Thank you.

Q. Was there a -- was there a study, a report or an internal decision document that lays out the consideration of decommissioning the coal-fired units and conversion to other fuel?

A. I'm -- I'm not aware of -- of that documentation as -- as my expert witness in environmental. So I'm not sure what analysis was done to convert from coal to natural gas. That would fall under another expert.

Q. Is there -- is there someone inside the company who would be familiar with that decision process to convert from gas to coal and -- and to --

A. Yes.

Q. -- close the coal-fired units and decommission them?

A. So, again, the -- the -- the conversion, yes, in 2003 and then also the -- the decision to decommission Units 3 and 4 in 2019. In both of those situations, there is analysis and we have people that can address that. It's just not something that I know.

Q. Can you identify for me who's the person most knowledgeable about the decommissioning of the coal-fired units?

A. Well, we would reach out to someone in our Power Generation Group that would have been responsible for making determinations on which units operate on which fuels or whether or not they continue to operate.

Again, as the environmental witness, that's not particularly my expertise. I can explain exactly what operations were going on or what was managed with the waste. But what decisions were made on particular fuel types, outside of the fact that, you know, we converted from coal to natural gas in 2003 --

Q. And so if there were a Company study of the costs of decommissioning and conversion, that -- that would be within someone else's area of expertise?

A. So, again, the -- the decommissioning and -- and the change from natural gas to coal are -- are two separate things. The -- the switch from coal to natural gas would have likely not looked at decommissioning at that time because it was perceived that those units would run for many years.

Q. I apologize. I mean, again, only the decommissioning of the coal-fired generating units.

A. So only the conversion from 2003 from coal to natural gas?

Q. I understand you. Thank you. You -- you --

A. I apologize.

Q. No.

A. I'm trying -- I want to answer your question.

Q. No. You're -- you're helping me here. Some of these terms get a little slippery in the literature --

A. Understood.

Q. They get a little slippery in the literature and in the regulations. And so we're trying to -- I'm trying to track through how the company uses them in actual practice and that's helpful. I appreciate it. Thank you.

Let me move to the Bremo plant. Is that -- did I pronounce it correctly?

A. We -- we say Bremo, but who's to say that's right?

Q. I'll say it the way you say it. It's your plant. It's not mine. It's your plant.

Let me move to the Bremo plant. And there were -- that's -- that's a very old plant. It was operating back in the 1930s, right?

A. 1931. Yes, sir.

Q. Okay. When did it cease to operate as a coal-fired generating plant?

A. So that was in 2014 --

Q. Right.

A. -- that those units were converted to natural gas.

Q. They were converted -- all of them converted to natural gas. Were any of them permanently decommissioned?

A. Not at that time. It was only two units, Unit 3 and 4. Unit 1 and 2 would have been retired sometime in the '70s, I believe.

Q. All right. And there were -- at that time, there were three impoundment -- surface impoundments at the plant, the East Pond, the North Pond and the West Pond, correct?

A. Yes, sir.

Q. The East Pond, as I understand it, operated up until -- or received coal ash waste up until sometime in the 1980s.

Do -- do you know a more precise date than what I have?

A. Yes. Mid-1980s is what our records show.

Q. Okay. And -- and at the time that it ceased receiving additional ash, what actions, if any, did the Company take with respect to the impoundment?

A. Very similar to Possum Point A, B, C. There was an area that did receive some level of cover. That was, again, for access to the toe of the berm for the North Pond because there -- if you've seen a figure, they're -- they're adjacent to each other. But then there was a portion of the pond that was left open and continued to function for stormwater purposes following that.

Q. And, again, was the situation similar with -- with the East Pond as it was with the Possum Point A, B and C ponds, that there was no dewatering of the impoundment?

A. Correct.

Q. There was no diversionary structures created to divert stormwater or remove the ash from contact with groundwater?

A. There -- there were no capping or -- or measures of that nature; again, as there was no regulatory requirement or standard to do so.

Q. I'm not interested in the regulatory requirement, just in what the Company actually did.

A. Understood. I think it's an important clarifier, though, and that's why I would like to add it, if you so allow.

Q. We will -- we will discuss that, yes.

The North Pond and the West Pond continued to receive ash until the conversion of the coal-fired units to gas-fired in 2014, correct?

A. The -- the North and the West. Correct.

Q. Did they thereafter continue to receive any other waste streams?

A. Yes. The East Pond continue -- and continues today to receive other waste streams.

Q. That's the East Pond.

A. I'm sorry. The West Pond. I apologize. Let me clarify. The West Pond continues to receive waste waters to this day.

Q. And what -- what -- what are those, what waste waters?

A. So there's contact storm water and sumps from draining inside of the station that go to a pond on site. And then in accordance with our -- our state NPDES permit, that water, along with the on-site sewage treatment discharge, is routed to the West Pond before discharge.

Q. The North Pond does not continue to receive any waste streams?

A. No, it does not.

Q. When -- when those ponds received -- ceased receiving waste coal-ash, what actions did the Company take with respect to those ponds?

A. So with the timing being slightly different with Bremo, the CCR Rule was finalized in 2015. Shortly after, we converted to natural gas. So we started moving ash from the West Pond to the North Pond. We had done this for many of years. We did it by hydraulic drudging.

In fact, we never sluiced directly to the North Pond. We always sluiced to the West Pond and then hydraulically dredged to the North Pond to make more room in the West Pond. And that was because of the other waste water streams that went there.

So we began that operation, which moved not only the water but also ash from the West Pond to the North Pond once we were to a level where the pond could not be, you know, dredged further, because you have to have enough freeboard for your barge. We switched over to a mechanical excavation and continued consolidation to the North Pond.

Q. And -- and would I be correct if I understood that there was no dewatering of either of the ponds? One of them was continuing to receive waste streams, the -- the West Pond, and neither were dewatered.

A. Well, actually, they -- they were actively being dewatered through the -- the hydraulic dredging from the West Pond --

Q. Okay.

A. -- to the North Pond.

Q. All right.

A. And then once we switched -- again, once the barge couldn't, you know, actively --

Q. Right.

A. -- get material anymore, when we switched to that, we did have to begin dewatering, which would have been in 2016, the West Pond, in order to access the remaining ash to excavate to the North Pond.

Simultaneously, we were dewatering the North Pond because we were placing additional ash in that pond. And as such, we needed to dewater for structural reasons as you're applying additional ash to be able to get vehicles in and out of the pond.

Q. These activities that you're describing were all undertaken really beginning in about 2015, 2016?

A. This is correct. The CCR Rule became effective in April 2015. And under that rule, it provided an option to close within three years as an inactive impoundment. And so the Company moved forward with that in an effort to close the ponds under the inactive provisions and -- and with it, you know -- you know, expediting those closures.

Q. I apologize to you, because the information is scattered around in multiple --

A. Understood.

Q. -- testimonies, so I'll ask the question here because I have one piece in front of me and to avoid flipping back and forth in the notebook.

Were any of the three impoundments at -- at Bremo, the East Pond, the North Pond or the West Pond were not lined? Were any of them lined?

A. No. All three of those ponds were -- were not lined.

Q. And when was ground -- was groundwater monitoring installed at any of those three ponds? And if so, when?

A. Yes. So the Bremo Power Station North Pond began, in accordance with its NPDES permit, monitoring in the year 2000. May 10th, 2000, was the first event there. And then the West and the East Pond began in 2013.

Q. Was that at time of permit renewal?

A. Yes, sir.

Q. The East Pond had ceased receiving ash in the 1980s, but it was still permitted in 2013?

A. Yes. There -- there was that one corner that I mentioned where stormwater still --

Q. Okay.

A. -- continued to collect, and so it was still a -- a -- a regulated impoundment and outfall.

Q. And the first -- well, let me back up for a minute. When the North Pond permit was issued in 2000 and permitting -- and groundwater monitoring was required, were there any exceedances at that point or was that a standard permit condition that was -- the Department was requiring of all new permit issuances?

A. So some of this information is -- is in my rebuttal. The -- the groundwater monitoring in Virginia at its surface impoundments was an evolution. And it was in 1998 when the state, because all the regional offices were taking different approaches based on their environmental knowledge of that particular area and the uniqueness of the site, they passed a guidance that laid out a measured step process for installing monitoring wells. And so in 2000, when the permit was renewed, they added groundwater monitoring wells at that time, and then we continued to monitor.

And the way that the guidance is set up is that based on the results and any exceedances or -- or concerns, you start with one upgradient, one or two downgradient. Then you expand your network. And so as of 2010, the number of wells have not been increased. It was still two wells for that one and there had been no concern to expand or require any sort of site assessment or risk assessment of the site.

Q. Other than for the Possum Point Pond E, where monitoring was started in 1990, did -- had the Company started groundwater monitoring at any of the other impoundments before 2000?

A. Yes.

Q. Which ones? Just so I get it all right now and get it all on the chart at one time.

A. Understood. And you -- you may want to -- Chesterfield began the upper ash pond in 1985, lower ash pond in 1986. And Possum Point, just to -- to get all of those, A, B, C began in 2016 in accordance with the CCR Rule.

Q. Right.

A. Pond D was 1985, and Pond E, Echo, was 1990.

Q. 1990. Let's -- let's go back to Possum Point Pond D then. What was the occasion that caused the monitoring to begin in 1995? What -- what occasioned that?

A. You're asking Pond Echo, correct?

Q. Well, I thought you told me it was Pond D.

A. Pond D, Delta -- and I'm sorry. I -- my -- my -- I tend to blend those two.

Q. Okay.

A. So I'll stick with Delta and Echo, if that's okay.

Q. That's fine.

A. So for Pond Delta, 1985 is when it began.

Q. And what -- what -- what occasioned the start of groundwater monitoring in 1985?

A. So that was added as a permit condition based on the permit writer's review of the site and initiated because of, you know, their site-specific determination that they wanted groundwater monitoring on that particular pond.

Q. What -- what were the site-specific conditions? Do you recall?

A. It was likely due to the placement of the oil ash, as that was a --

Q. The oil ash.

A. -- a new condition.

Q. Okay. Let me stay away from Chesterfield for a minute. Those were the other two you gave me, because I want to come back to Chesterfield in just a moment.

Let me go back to Bremo and see if I have any other questions about Bremo at this point. Let's -- let's go to Chesterfield then next.

The three impoundments at Chesterfield are continuing -- or were continuing to receive ash waste up until 2017 and -- and even in the case of the -- well, the landfill is not an impoundment. But the two impoundments received waste ash up until 2017, correct?

A. Yes. That's correct.

Q. Okay. And I think you said the upper ash pond, groundwater monitoring began in 1985.

A. Yes. 1985 for the upper; 1986 for the lower.

Q. And what was the occasion that prompted the installation of groundwater monitoring at the upper ash pond in 1985?

A. Again, it was part of that evolution of the NPDES program for the Virginia Department of Environmental Quality and so was added into our NPDES permit to initiate groundwater monitoring at that site.

Q. Do you recall what -- what -- what site-specific conditions may have caused the requirement of groundwater monitoring there and not at some of the other impoundments that you had at the time?

A. I -- I do not have specifics. Those were unique determinations made by the permit writer based on the site's location, the site's geology and ash.

Q. What about the lower ash pond in 1986? What occasioned the requirement for groundwater monitoring in 1986?

A. Again, that would have been based off of the Department of Environmental Quality's professional judgment.

Q. And you don't recall any particular conditions that existed at the site that would have prompted that, such as exceedances or other -- other noted problems at the site?

A. No, sir.

Q. Okay. Thank you. With respect to the Chesterfield Energy Center, there was what's called the bottom ash pond that received ash waste up until about 2014, correct?

A. Correct.

Q. What -- why did that impoundment cease to be receiving ash after 2014?

A. That station was decommissioned beginning in 2014. So there was no longer combustion of coal.

Q. All right. And -- and I'll ask you the same question. Is there someone in the Company knowledgeable about any studies or analyses about the decommissioning decision at the Chesterfield -- at the Chesapeake Energy Center, the costs associated with decommissioning? Is there someone knowledgeable about that subject?

A. Yes. I mean, we -- we would have justified why it was prudent to close that station.

Q. Would that -- would that have been in the form of some sort of study or analysis or decision document?

A. As with all of our decommissionings, it would have -- it would have been based on an economic analysis of why that unit was no longer viable and should be shut down permanently.

Q. And would that -- that analysis have considered also the cost of decommissioning and closure of the unit?

A. It -- it -- it may or may not have.

Q. It may or may not have?

A. Yeah. I'm not -- I'm not -- I'm not in that part of the company. What I do know from my involvement in rate cases is that there is extensive analysis any time we decide to shut down a unit or retire or even cold storage. But, again, that's -- that's not my purview or expertise.

Q. All right. I'll -- I'll leave you alone on that. I think that's the same situation we discovered with respect to the Possum Point Plant, so I won't go there.

Mr. Williams, are you familiar with a -- the Electric Power Research Institute?

A. Yes, I am.

Q. The Company's a member of the Electric Power Research Institute?

A. We are. The membership varies as the membership is based on different sections of EPRI, but we -- we are members of EPRI for some memberships.

Q. Do you regularly consult EPRI publications in connection with the performance of your job duties?

A. We do in some areas. We work with EPRI as it pertains to compliance with 316(b), Bravo. I have not worked with them directly on coal ash.

Q. You have not. Have you consulted any Company publications, reports, studies or analysis --

A. Yes. I'm familiar with --

Q. -- EPRI -- EPRI reports?

A. I'm familiar with the reports. Unfortunately, EPRI was pretty far behind when the CCR Rule became effective. So most of the regulated entities had to figure out how to comply before they could really get any studies or analysis done. So with that regards with compliance with the CCR Rule, there hasn't been much support there.

Q. Do you have any familiarity with a 2004 EPRI study on the decommissioning of -- of coal-fired generating plants?

A. Yes, I am familiar with that one.

Q. Tell me what you know about that study.

A. That's a study EPRI put together that looked at, I believe, four stations and provided case studies for what sort of measures would be taken for decommissioning and, ultimately, closure of the site.

Q. Have you used that study or those case studies in connection with any of your assignments?

A. I've not used those directly because we've not been in a situation where we were decommissioning -- permanently decommissioning a station. Through our compliance with the CCR Rule also -- that document long predates, by 11 years, the CCR Rule. So some of the information in it is -- is outdated with regards to what regulatory standards we have to meet.

Q. And so that document would not have been pertinent -- do I understand, in your view, would not have been pertinent to the conversion from a coal-fired generating unit to another fuel because that would not involve the decommissioning of the plant itself?

A. Yes. That would have been an economic analysis on which fuel is ideal for the customer and -- and best position. It would not have been reference for perspective of decommissioning, as we were not decommissioning those units. We were simply changing fuel supply as we -- we've done a number of times throughout the life of these sites.

Q. Do you have any recollection of the conclusions from that 2004 EPRI study with respect to the costs of closure of waste impoundments and landfills at coal-fired generating plants?

A. I -- I have read the recommendations. I'm unclear if there's a particular one of interest.

Q. What do you recall about the recommendations? What do you recall?

A. They gave a relative analysis of -- of what overall challenges or items you may face as you decommission a station specific to those four case studies that they referenced.

Q. And -- and the EPRI report also cautioned that the cost of closure of coal ash impoundments and landfills could be the most significant part of the cost of decommissioning the plant, did it not?

A. So the report did state that. But, again, that was specific to those four case studies, and it's important to recall of -- of what your intended land use is in the end. So for our analyses, if we looked at our stations, none of them were on -- at that time, in 2004 or after, were scheduled for decommissioning. There's no intent to ever sell that land or turn it over to someone else or develop it in other ways. So it would have been intended that you would keep it at industrial levels.

And I believe this report, there were some reuses of some of those properties that required much more extensive potential mitigation than would have been required for an industrial site. And -- and, again, you know, we -- we were not decommissioning those -- those sites to that level.

Q. Thank you. Thank you for the clarification.

Mr. Williams, in -- well, this goes to your rebuttal testimony, so let me hold onto that question. If you'll give me just a moment, I want to see if Staff's got some questions that I may need to ask that I haven't covered.

A. Yes, sir.

Q. I think the remaining questions that we may have go to your rebuttal testimony, so I'll hold onto them until then. You've given me a good basic knowledge. Thank you.

CHAIR MITCHELL: Commissioner Brown-Bland?

EXAMINATION BY COMMISSIONER BROWN-BLAND;

Q. Good morning, Mr. Williams.
A. Good morning.
Q. I just have a few questions. Some of them might overlap the questions you already responded to, but these are just clarification straight out of your direct testimony.
So on Page 9, when you began to address Possum Point, I'm just trying to be clear on the original -- with regard to the original Pond D. It says Pond D -- your testimony says there on Line 20 the original Pond D was constructed in the early '60s, before A, B and C reached capacity and received CCR until 1971.
Does that mean that's how long Pond -- Pond D stopped receiving -- original Pond D stopped receiving CCR in 1971? Is that a --
A. Yes.
Q. -- reference to -- to Pond D?
A. So -- so -- yes. The -- the original Pond D would have ceased accepting CCR in -- in '71.
Q. And it began receiving it when? Do we know?
A. So then -- let me make sure I understand the question.
Q. Original Pond D.
A. Original Pond D, when it would have started

receiving -- that would have been, again, in that -- that 1960s time frame, when Ponds A, B and C were -- were reaching capacity. So 1967 -- so we have Pond D is -- in the 1960s was under construction and put into service.

Q. So do we have a -- we don't have a date? Do we have a date for original Pond D?

A. I don't have an exact date. It would have been the early '80s that would have began operation.

Q. '60s, you mean? Original Pond D?

A. I'm -- I'm sorry. Original Pond D would have been '60s, yes.

Q. But no specific date you don't have?

A. That's correct.

Q. Okay. And that pond, I think we established, was not lined?

A. That's correct. It was on top of a thick natural clay layer that when we did expand the pond, it was tested and confirmed that that was adequate as a clay liner. It was multiple feet thick and met the natural standard.

So while it wasn't constructed with a liner, when we expanded D, it met the requirements for the liner that we had to construct for that overall pond.

Q. That was in the '60s, though?

A. When that pond -- the original one was constructed?

Q. Right.

A. Yes, ma'am.

Q. So at that point, you looked and there was -- there was -- there was something -- a requirement that indicated to you that the clay liner was a good thing?

A. Well, there wasn't a requirement. I was just commentating that while we didn't install a liner on Pond D, when we reconstructed Pond D and did investigation to meet the requirements that were applicable at that time, we indeed found that there was substantial clay underneath Pond D.

Q. That -- that's when you learned about it. That was in the -- '86?

A. Correct.

Q. Okay. And so that was just the natural clay liner that -- that existed from the beginning?

A. Correct. That was just natural clay soils. Again, at -- at that time, there were -- there were no requirements for liner systems.

Q. Clay soils. Okay. And the Company -- the -- the last sentence on the -- Page 9 says, "The Company completed construction on new Pond E in 1968."

And new Pond E, was it lined?

A. No. As I stated earlier, Pond E is not lined.

Q. All right. So going back to new Pond D, how long was -- was new Pond D in -- how long did it take -- when did the planning for new Pond D begin and how long did it take, you know, including any engineering or anything for Pond D?

A. The --

Q. New Pond D.

A. The -- the modern Pond D, Delta, would have started in the early '80s.

Q. So can you -- can you quantify any better? Early '80s to you means?

A. Yeah. It would have been the early '80s that the engineering would have started. That was, you know, when -- when we would have started developing a plan for what we needed for future ash storage.

Q. So in the early '80s, why was new Pond D being lined?

A. Yeah. so what -- what you'll find with our sites is, you know, there -- there -- there's a mixture between some that have liners, some that don't. In the case of Pond D, as I explained earlier, in the corner of Pond Echo, which is adjacent to Pond Delta, there had been oil ash placed. And as a result of groundwater conditions in that area due to that oil, we reached into a -- a special agreement order with the state to construct Pond D and construct it with a liner. And the idea was to allow the -- the -- the concentrations from the oil ash placement to attenuate, which they did, while still allowing continued operations.

So it was not based on a -- a new regulatory standard or something that was applied to all ponds in Virginia. It was a unique situation, unique decision to Pond Delta driven by the environmental regulator.

Q. And I started to catch onto this when you -- when you and Commissioner Clodfelter were discussing Bremo, so I may have misheard this as to Possum Point. But it's my understanding in your direct testimony that Pond E -- or D and E both received no more coal ash after the conversion to natural gas in 2003, or did -- or did they continue to see -- receive some?

A. They ceased receiving coal ash in 2003. That was the conversion. Pond E, Echo, continued to receive other waste waters following 2003.

Q. On to Bremo, which is on Page 10, the East Ash Pond, it says, stopped receiving CCR in the mid-1980s. Is that because it was full or was there --

A. Yes.

Q. -- other reasons?

A. Yes. Yes. It's because it was full and -- and the Company constructed the West Pond.

Q. And the West Pond, you mentioned, was dredged and -- or -- or ash was moved into the North Pond.

Was that just to make room in the West Pond? Is that the only reason?

A. Yes. So if -- if you're talking about historic operations, yes. When we were operating the West Pond, we would -- in order to keep an adequate freeboard in that pond to allow for the settlement of the sluice waters, as well as the other waste waters that were routed there, we would periodically dredge to make more availability and place that ash in the North Pond.

Q. Okay. With regard to Chesterfield, the lower ash pond and the upper ash pond, were these both on site?

A. Yes, ma'am.

Q. And what was the reason for the dredging of ash from the lower ash pond to the upper ash pond?

A. So the -- the lower ash pond operated as the primary sluicing location. As it was reaching capacity, the Company built the upper ash pond. But ash continued to be sluiced to the lower and then, much like with the West and the North Pond, it would be dredged or sluiced from the lower pond to the upper pond. So it was to -- to make availability.

And then in the late '90s, early 2000s, the upper pond was filling up, and at that point, it converted to more of a dry operation where ash was excavated from the lower ash pond and then trucked up to the upper and placed, which allowed it to construct above grade.

Q. All right. And over -- well, on Page 11, where you discuss the Chesapeake Station there, it indicates that the operations at Chesapeake ceased in 2014 and that that was decommissioned.

Can you discuss more about what the decommissioning plan said about permanent closure there?

A. With regards to the ponds?

Q. With regard to the decommissioning of -- of the -- of those generation units.

A. As -- as far as the actual demolition of the -- of the power block?

Q. Uh-huh (yes).

A. Yeah. There -- there -- there was a plan developed for deconstruction of that power station and removal of the materials, which the contractor came in and -- and completed starting in 2014.

Q. And then what did it -- what did it say with regard to the ponds?

A. So the -- the -- with the ponds -- and it's important to understand the history of Chesapeake. So Chesapeake had, beginning in the 1950s, when they began operating, sluiced the ash to a pond on site and then, much like many of the other coal stations, switched to oil in the early '70s.

And then when they went back to coal, now with the requirements of the Clean Air Act, there were substantial improvements to the air pollution control equipment that had to be completed. And so at that time, the Company during that process installed pneumatic fly ash management and constructed a landfill on top of the historic ash pond. The bottom ash continued to be sluiced to a small pond that was also on top of the historic pond.

So in order to build that landfill that was permitted in, subject to check, 1985, that permit required closure in place for that landfill and they treated the peninsula as the monitoring and -- and capping of that site. So the plan had always been, since the -- the landfill was constructed at Chesterfield -- Chesapeake to close in place, and that plan did -- did not change with decommissioning.

Q. Okay. Now, with regard to Yorktown, your testimony says in 1985 the Company constructed a lined ash fill. But Yorktown began operations in 1957. So was ash being handled between '57 and '85? And if so, how?

A. Yeah. So Yorktown began operation in -- in 1957, and Yorktown was a very unique station in that it was located next door to an oil refinery. And so that station had a sort of symbiotic relationship where the petroleum coke, waste byproduct of oil, was burned at the stations in -- in power -- in station Units 1 and 2. And so that ash -- the petroleum coke ash was taken off site by a contractor for disposal is how that site operated.

Much like the other units, they converted to oil and then when converted back to coal due to the high cost of oil, there were significant air pollution changes that were made. They put in a pneumatic system for the fly ash and constructed a landfill. That landfill was --

Q. Is that the 1985?

A. That's the 1985. That's part of conversion back to coal. We needed a disposal location and the landfill was constructed.

Q. And how long did it take to plan and permit that landfill?

A. Very similar to -- to Pond D, the -- you know, the documents began in the early '80s for permitting and approvals through the local government and the state regulatory agency.

Q. Now I'm looking over at Clover. There it says the

CCR has been taken to an on-site landfill. Is that one -- is that -- when was -- when was that landfill permitted? Was it part of the '85 -- that general time frame?

A. Yeah. So -- so Clover is a much newer station. Clover was commissioned in 1996. So the landfill was constructed as part of the initial operations of the site for the fly ash. So that landfill's been present since the station began operation in '95.

Q. Is that -- is that a -- a lined landfill?

A. Yes, that is. The solid waste regulations in Virginia, which became -- were -- were promulgated in 1991, it was permitted under that and required to have a -- a liner system under those new regulations.

Q. Then moving on to Mount Storm --

A. Uh-huh (yes).

Q. -- there around Line 17, it says, "Dry fly ash and bottom ash are stored in the on-site lined Phase B landfill that is permitted by West Virginia."

When was that permitted? Do you know?

A. That landfill was permitted in the mid 1980s.

Q. And what was the situation with the coal ash before using the landfill?

A. So the -- the station had the -- the -- the ponds that are now retrofitted and that would have managed the ash. Early on operations, it would have been mostly just bottom ash because there were not the air pollution controls that we have now that generate the fly ash.

Q. Okay. And so how many ponds were part of that?

A. I believe there were a total of four ponds there, small ponds next to each other. And then they also collected ash that was -- as I understand, were utilized in mining operations.

Q. And revisiting Possum Point one more time just because I'm moving forward through your testimony on Page 13 -- but just to be clear with the -- between the original Pond D and the new Pond D, so that's when the A, B, C -- the ash from A, B, C and it says E were consolidated into new Pond D -- into new Pond D. But the old -- the ash from original Pond D, is it all still part of Pond D or --

A. Yes, it is. Yeah. The original Pond D, again, when -- when the design was done in -- in the 1980s, it was found that it was sitting on an adequate natural clay that met the liner spec for the new design that the state had -- had requested as far as liners.

And so around that pond, a slurry wall was placed and then the liner was built up above it and then the modern Pond D then filled in on top of it. So it's all within the same footprint.

Q. And I'm taking it from -- I'm -- I'm inferring from what I'm reading in your testimony that there is a plan to close new Pond D as well?

A. Yes. The -- the plan the Company was working towards was closure in place with consolidation of Pond D. However, as stated in my direct testimony, there was legislation passed in Virginia that will require now the excavation of Pond D.

Q. Okay. Then going back -- I'm on Page 16, but back to Mount Storm, up here's where it talked about the ponds. I knew I had read something about Mount Storm ponds.

So your testimony says about Line 16 -- 16 on Page 16 that the five original ponds were closed by removal. When -- when did that occur?

A. So that would have -- that would have began late 2015, 2016 with the passing of the CCR Rule. Those ponds did not meet the rule requirements for liner and -- and other siting criteria. And so those ponds were removed, the ash placed in Phase B and then they were what the rule calls retrofitted. New ponds were -- were built on top to continue to service the station.

Q. So there's still ponds in the footprints of A, B, C and D?

A. Correct.

Q. And so prior to it being retrofitted and the original ponds having that ash removed, up until -- how long or up to what period of time did A, B, C and D continue to receive ash before it was retrofitted?

A. So up until that -- up until those ponds were excavated, it would have continued receiving some amount of bottom ash and -- which was the -- the reason for retrofit being required. So we did them in phases so that we could continue to have the waste stream go to those ponds.

Q. Now, with regard to all the -- the ponds that are involved in these plants for which recovery is being sought now, did they -- well, skip -- skip that for now maybe.

So then in Mount Storm it says that the construction of the final ponds used a concrete liner; is that right?

A. There's a concrete liner on -- on top of the liner. So the -- the concrete is to protect it. So it still has the liner required by the regs, which is a composite liner, but then you line it with concrete so that you can get into it and clean out the pond without damaging the liner underneath, similar to the Clover ponds.

Q. And concrete, that's the normal -- that's what you would normally use?

A. To protect and armor the liner system, yes.

Again, the liner system is a combination of clay and HDPE, high-density polyethylene. The -- the concrete is a protection barrier on top so that when you're going in and removing materials, you're not damaging that liner underneath.

Q. Now -- now going back to -- as I was asking about all the ponds, are you able -- is the Company able to -- or have maintained records that lets you know year by year how much ash is added to -- or how much tonnage of coal ash is added to a pond or --

A. That was a discovery request that we responded to, and we -- we did not locate records of -- of that tracking for the impoundments. We did have some records for Chesterfield because there we were actually moving ash from the lower to the upper, so there was a means to track that. But in the other stations for the sluicing operations, we did not track that on an annual or otherwise frequency.

Q. So to your knowledge, there were no periodic records kept that would help you indicate --

A. Not --

Q. -- the amount of ash being added at any particular -- over any particular period of time?

A. We -- through the, you know, 240 hours of searching and -- and thousands of records we identified, we did not identify any records of volumes and rates for the ponds.

Q. You didn't find any records, but did -- in -- in checking with colleagues -- I assume you did at some point in time -- was anyone aware that that knowledge had been maintained or tracked?

A. In -- in my discussions, they would have -- they recalled doing periodic evaluations to determine how much freeboard was left for planning purposes, but not a recollection of, you know, monthly records or annually or anything of that nature.

Q. All right. Thank you.

EXAMINATION BY CHAIR MITCHELL:

Q. Just a few questions for you.

A. Okay.

Q. In your testimony, you referenced the legislation that Virginia enacted earlier this year that calls for -- basically that -- that prohibits closure in place for those facilities located in the Chesapeake Bay watershed.

A. Yes, ma'am.

Q. And you indicate that prior to the -- this legislation, the Company's plans called for closure in place for those specific facilities.

What can you tell me or tell the Commission about the -- the difference in -- in the Company's plans versus what the Legislature ultimately determined to be policy for these facilities, and why -- why the -- why the difference?

A. Okay. So I'll start by summarizing our initial closure strategy. So when the -- even leading up to the rule being passed and subsequent to the CCR Rule being passed, you know, one of the options is closure in place.

We did provide some reports that -- that analyzed those options and determined that closure in place was the best option, and we felt like that was the most prudent path forward at that time based on those regulations, especially given that in 2005, when -- when the rule was first passed, if you closed within three years, you got relief from other provisions of the rule that would have been very beneficial in the long term. And so we moved forward with capping-in-place and consolidation to -- to limit that footprint that was ultimately capped-in-place.

Through that, as I don't think I need to tell this Commission, there's been a lot of interest on coal ash, a lot of debates. And, you know, through extensive studying of -- of the options and the costs associated, Virginia made a policy decision that they would require excavation of these ponds at -- at our facilities based on a potential future concern and, as such, felt like the best path forward was that it would be removed and placed in a lined landfill.

Q. So the -- the -- the future concerns that you -- that you mentioned, what -- what would those -- what, future concern of impacts to groundwater, impacts to surface water? Can you expand on that?

A. So I -- I certainly can't speak for the -- the General Assembly. I -- what I can say is, you know, we -- we provided the information on our current condition of groundwater -- that was part of Senate Bill 1398 -- which shows that there are not currently risks to off-site human health or the environment.

We also provided what options could be done if those one day presented themselves, such as remedial activities that you can do to address the groundwater while still leaving the ash in place. And after providing all that information, the General Assembly made the decision that they felt the best -- best path forward was excavation.

So further than that, I -- I can't really comment as to why they selected that position, as there are no current risks.

Q. So -- okay. Thank you. Has the Company been able to quantify the difference in cost associated with -- with closure in place versus removal?

A. I --

Q. Even just roughly.

A. Yeah, I don't have those numbers available, but, certainly, removal is more costly than closure in place.

Q. Understood. And -- and -- but the Company doesn't have a rough estimate yet with that?

A. I'm sure we have a rough estimate of it. In fact, in 1398, which we provided in the late-filed exhibits, that looks at the relative cost comparison of closure in place versus closure by removal. So that report does detail those costs that was included in the exhibit, and -- and the delta could be inferred from those two.

Q. Okay.

A. So we do have that information.

Q. Okay. Thank you.

CHAIR MITCHELL: Any additional questions from Commission? Commissioner Brown-Bland?

FURTHER EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Williams, just one last question. So Public Staff Witness Lucas on his Exhibit 5, it lists on there the amount of ash in each of the -- the ponds. It gives some number, and I believe they got that information from the Company.

A. Yes.

Q. Can you tell us how you arrived at -- at those numbers?

A. Yeah. So that was based off of surveys completed at -- at the time that we started to address these ponds for closure. And so what we did is a comparison of the current status, the current elevation of ash versus the design drawings and design information that we had for those ponds and generated the numbers based on that.

We also refined those numbers as we excavated the Ponds A, B, C and E and that was factored into the consolidated amount that's listed for Pond D, for example.

Q. So it was a number that you had to calculate, basically?

A. Yes, ma'am. It was a number that was calculated to determine the -- the volume at that time.

Q. Okay. And it wasn't based on any kind of prior tracking as -- as the ash went into the ponds?

A. No, ma'am. It wasn't a cumulative summary.

Q. All right. Thank you.

A. Yes.

CHAIR MITCHELL: Questions on Commission's questions? Ms. Force?

CROSS-EXAMINATION BY MS. FORCE:

Q. Mr. Williams, I'm Margaret Force for the Attorney General's Office, and I just had a couple of follow-up questions.

Commissioner Clodfelter had some questions for you about converting from coal to natural gas that -- and -- and whether there was a conversion or decommissioning involved. And I just wanted to ask you, are you -- when you were talking about the -- that conversion, were those plants where you had -- were using boilers and -- and steam generation at a coal plant and then converted the fuel to natural gas to -- to fire the boiler, or was it a new unit that was installed that was a combined cycle-type facility?

A. So in -- in all these cases, both with -- with Possum Point and with Bremo, it was conversion of existing boilers. Existing coal-fired units were converted to natural gas. There were not new units installed.

Q. So the -- you were converting the fuel source, but it was still a boiler that was used to generate steam to run the turbine generators?

A. Correct. Nothing changed except the fuel source.

Q. Okay. And -- but -- but the waste product from the generation of electricity at that point changed in terms of the fuel that you were using, so you didn't have the stream coming from the coal being burned?

A. Once we converted to natural gas, we were no longer burning coal. So -- so, yes, we were no longer creating coal ash.

Q. So when you talked about -- am I understanding you correctly then when you talked about not decommissioning the plant, it was still continuing to operate as a steam turbine generator, but you no longer had coal ash being produced and -- and sluiced to the ponds? Am I right about that?

A. Yes. That's correct. We -- we converted.

Q. So at that point, the ponds were designed, I guess, to accept the coal ash. Was there a similar need for the size of the ponds in order to handle waste water and that kind of thing or would they be out of scale with what you would use them for for waste water?

A. So, again, they were all permitted to manage multiple waste water streams.

Q. Uh-huh (yes).

A. So at that time, we continued to use them in their current format. There was no changing or -- or adjustments necessary to the ponds to continue managing those streams that -- with the ponds.

Q. So you didn't need to enlarge the ponds in order to accept the fact -- the change to natural gas? And would you design the ponds at the same size to accommodate the waste stream from a natural gas-fired steam turbine plant?

A. So I think there were two questions there. The first question is, you know, no, we did not need to expand the ponds with the conversion to natural gas. And, you know, I -- I would be speculating to say what -- if we would have never generated coal there what ponds would we have needed. So, you know, again, the -- the ponds didn't need to be enlarged or changed with the conversion to natural gas.

If it had never been a coal station, then, obviously, you -- you wouldn't need coal ponds and there would have been a completely different design made for the waste water there.

Q. Okay. I don't have other questions. Thank you.

CROSS-EXAMINATION BY MS. CUMMINGS:

Q. Hi, Mr. Williams. Just a few questions. Commissioner Clodfelter -- and, actually, I think also Brown-Bland -- asked you about Possum Point and -- and when you first started monitoring there.

Can you tell me when groundwater contamination was first discovered at Possum Point?

A. So as -- as stated, the -- you know, elevated concentrations of -- of constituents were detected prior to the 1986 special order. But to call contamination, you know, again, it's elevated concentrations based on the monitoring that was conducted there.

Q. But there were certain leachate that was of higher concentrations of elements that were of concern?

A. There were certainly concentrations detected. You know, I think it -- it goes back to the entire permitting schema in the U.S. and -- and how those are monitored.

So there were detections. The state evaluated those detections, and based on that, we agreed to construct the new Pond D in response to it and remove the oil ash in that location.

Q. There was a series of groundwater assessments that were done at that time, and that was done in compliance with -- or to obtain the 1985 permit at that site; is that correct?

A. So those studies were a requirement of the NPDES permit. So the way that the permit worked is it required groundwater monitoring. You reported those results to the state, and then based on their analysis of them, they may require additional actions. And in this case, they required that a risk assessment be evaluated for that site.

Q. And you indicated that oil ash was of concern. Were there other concerns about the waste stream in that pond?

A. There was also coal ash placed in that area, but the -- the primary concern was the -- the oil ash.

Q. The pyrites were also of concern, weren't they?

A. Yes, there were pyrites there as well.

Q. And can you tell us what pyrites are?

A. Pyrites are a natural component left over in the coal after crushing. It's a -- it's a harder piece of the stone that doesn't crumble when you pulverize coal.

Q. And part of the special order was also that a dry ash handling system be built originally, correct?

A. That was the original plan, yes.

Q. And what type of ash was that meant for?

A. That would have been for the oil ash and for pyrites.

Q. You also were asked about exceedances at Possum Point and whether or not they were within the compliance boundary, and you said that they were.

In North Carolina, the 2L rules here have a compliance boundary of 500 feet. Can you tell us what you meant in Virginia by the compliance boundary?

A. So in Virginia, they establish the facility boundary as being your compliance boundary. However, the wells -- their typical rule of thumb is to have the wells within 500 feet of the unit.

Q. And did you have wells around this compliance boundary to monitor this?

A. We had wells around the units at the dates that I provided.

Q. But did you have wells that specifically told you that you were in compliance at the compliance boundary at that time?

A. We did not have a network in that area. Over time, there were additional wells added to address if there was migration in that direction which confirmed that there was not. So the modeling was based off of the results of the wells closest to the impoundment that gave the characterization of the groundwater.

Q. But the monitoring results at that time led to these corrective actions that were in the special order being required?

A. Yes. That -- the -- the results from the wells at Pond D is what ultimately led to the path forward on the new Pond D.

Q. Commissioner Brown-Bland asked you about Yorktown as well and what the company did with the coal ash there prior to 1985.

A. Uh-huh (yes).

Q. Did Yorktown burn coal in the '60s, '70s and '80s?

A. So there -- there would have been some coal burned. As I mentioned in the response to the

Commissioner's question, the primary fuel at that time was petroleum coke from the oil refinery next door. There was an amount of coal ash that was blended in to -- to -- to meet that fuel need.

Q. And you indicated that this was taken off site to a developer and this is the site discussed in the Public Staff testimony as Chisman Creek; is that correct?

A. Yes. The ash was taken by a private contractor for disposal at Chisman Creek.

Q. And is Chisman Creek a Superfund site?

A. Yes, Chisman Creek is a Superfund site.

Q. And is Dominion currently remediating that site?

A. So Dominion sent waste to that site via a contractor. It was their location. They lawfully disposed of the ash there from the '50s up until, I believe, 1974. At that time, shortly thereafter, there were investigations and found to be contamination at that site. It was later pulled into the Superfund program and the developer could not -- or contractor that operated those could not remediate that site.

So Dominion stepped in as the responsible party, since it was ash from our site, and has done a number of different remediation projects there working closely with EPA, all the way up to the most recent, you know, completion and -- and awards for beneficial reuse of a former Super -- or current Superfund site.

Q. And what specifically was that award for?

A. It was beneficial reuse of -- of a Superfund property. So the -- it was highlighting that this Superfund facility has been ongoing active remediation and that other land uses have been put in place on that site.

Q. Was it for the land use or for the way you treated the water there?

A. So it's -- it's a reuse of the land use and -- and the protectiveness of the remedy that allows for the land use.

Q. Chairman Mitchell asked you about the legislation that was passed and how that changed your approach. And, initially, you indicated that the -- all the sites were to be capped-in-place and that was protective. But, initially, there was a distinction on each site, at Bremo and Possum Point and others, that the surface impoundments -- the historic surface impoundments would be excavated and put into one site; is that correct? That was the initial plan.

A. That was the inial plan with the passage of the CCR Rule, yes, would be consolidation and cap-in-place so that there was one footprint where the material would be closed and placed.

Q. And excavation of those historic ponds would allow the Company to avoid the long-term monitoring requirements of the CCR Rule.

Is that one of the reasons that option was chosen?

A. Well -- well, it -- it's not just that. It's all the requirements, the various documents that have to be generated, other information maintained, long-term management of the pond. So, for example, had you closed all the ponds in place, you'd have to maintain the caps at each one of them. You'd have to do the inspections at each one of them.

By consolidation, under what was later vacated, but at that time the -- the inactive provisions would have prevented the need to do that in those locations.

Q. And that exemption was for legacy coal ash ponds.

A. It was for ponds that no longer accepted ash after a date established in the rule.

Q. And when was that vacated?

A. Excuse me?

Q. When was that rule vacated?

A. That rule was vocated -- vacated in 2017, I believe, subject to check.

Q. I believe it was June of 2016.

You indicated that there are no current risks, but that the Legislature chose to excavate anyway. Is that a fair representation of what you said?

A. I -- that is a fair representation. All the data presented and the analysis shows that there's -- there's no off-site risk to human health or the environment at any of these coal ash impoundments of ours.

Q. But the legislation also required you to provide alternate water supplies off site?

A. It required us to do an evaluation of those potential sites and -- and address water.

Q. And have you provided alternative water supplies off site?

A. So we have provided alternative water to -- or an offer for reimbursement for connection to residents along Possum Point Road, near the Possum Point Power Station.

Q. And there's ongoing litigation there, right, from neighbors alleging impacts to their wells?

A. Yeah. There -- there are, and there -- there are ongoing litigation, which I can't comment in detail on as ongoing litigation. However, yes, we did provide water.

I think it's important for context to -- to clarify that with the CCR Rule, there was substantial additional monitoring that was required and new constituents that hadn't been monitored for. And the neighbors had concerns. I personally met with those neighbors and -- and heard their concerns. And so as -- you know, in an effort of -- of -- of addressing those concerns and being a good neighbor, the offer was made to allow reimbursement if they would like to hook up. Some neighbors took it; some did not.

However, the data continues to show that the groundwater wells on that side of the pond have not exceeded health base limits. In addition to that, there is a hydraulic divide that separates our pond from those wells on the other side, locally referred to as a beaver pond.

Department of Health monitored those wells and did not make any recommendation for them not using them. And on top of that, the Prince William County hired a third-party consultant who evaluated it and agreed that there were no impacts coming from our station to -- to those wells.

Q. You say that there are no off-site impacts in general. Are there on-site impacts?

A. Well, I think, again, that gets back to the whole terminology of impacts. And I think that's important because it's discussed a lot and that term is used a lot in this case.

So the entire permitting and regulatory schema in the United States ultimately has some level of an impact.

So think of every single exhaust stack in this country. It has an air permit. That permit establishes emissions limits.

So there is some sort of impact. The important part is and the important thing required by the environmental laws is that those are mitigated or there's a means to manage those. And these ponds are -- are no different than when we hop in our car and start our car, the exhaust pipe has impacts from.

There's assumed when you're constructing and permitting these things that you may find localized impacts, but there are mitigation steps in the permits for you then to evaluate and respond based on those results at varying levels of degree as a result of what the results tell you.

Q. And by impacts, you mean pollution?

A. By impacts, I mean, you know, increase of constituents in that particular location.

Q. You talked briefly about the legislation the Virginia State Assembly passed.

Did Dominion have any lobbying efforts with regard to that legislation?

A. So Dominion, as we have on -- on prior legislations, provided information to the General Assembly. We did the two years prior one -- a study on all the various options; the most recent year before that, a study on what recycling would look like in detail; and then we continued to answer questions that were posed to us by the General Assembly members.

Q. Did you actively support the legislation?

A. I did not actively support the legislation. I answered questions as it's the role of the General Assembly to legislate in Virginia.

Q. Thank you. That's all the questions I have.

MS. CUMMINGS: Commissioner Brown-Bland, I'd like to note that they did answer in discovery some year by year coal ash volumes that we can provide.

THE WITNESS: As I mentioned for Chesterfield. Thank you.

MR. SNUKALS: Chair Mitchell, I just have a few redirect questions.

REDIRECT EXAMINATION BY MR. SNUKALS:

Q. Public Staff asked you some questions about Chisman Creek. Do you recall that?

A. Yes.

Q. Is Chisman Creek subject to the CCR Rule?

A. No, it is not.

Q. What was the purpose of your testimony in this case?

A. So my -- purpose of my testimony is to provide the details on our CCR compliance activities that are the subject of this rate recovery period.

Q. Public Staff counsel also asked you about the closure strategy prior to the Virginia legislation requiring that the Company excavate its ash basins in the Chesapeake Bay Watershed.

Has any witness, including any Public Staff witnesses, criticized, questioned or recommended disallowances for the Company's closure strategy to comply with the CCR Rule?

A. No.

Q. Are costs associated with the Virginia legislation included in this case?

A. No.

Q. I have no further questions.

CHAIR MITCHELL: Okay. I believe that you may step down at this point, Mr. Williams.

Any -- any motions from Dominion?

MS. GRIGG: Not at this time.

CHAIR MITCHELL: Okay. Okay. Well, we will take our break for lunch. We will return at 1:30. We'll go back on the record at 1:30. So let's go off the record, please.

(The hearing was adjourned at 12:28 p.m. and
set to reconvene at 1:30 p.m. on Tuesday,
September 24, 2019.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF FRANKLIN)

I, Patricia C. Elliott, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appear in the foregoing hearing were duly sworn; that the testimony of said witnesses was taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to this action; and further, that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 26th day of September, 2019.

PATRICIA C. ELLIOTT
VERBATIM REPORTER/NOTARY PUBLIC
NOTARY #19940480043