PLACE: Held via Videoconference

DATE: Thursday, September 3, 2020

TIME: 1:31 P.M. - 4:31 P.M.

DOCKET NO.: E-7, Sub 1214

E-7, Sub 1213

E-7, Sub 1187

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-7, SUB 1214

Application of Duke Energy Carolinas, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

DOCKET NO. E-7, SUB 1213

Petition of Duke Energy Carolinas, LLC,

for Approval of Prepaid Advantage Program

DOCKET NO. E-7, SUB 1187

Application of Duke Energy Carolinas, LLC,

for an Accounting Order to Defer Incremental Storm

Damage Expenses Incurred as a Result of Hurricanes

Florence and Michael and Winter Storm Diego

VOLUME 12

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P R O C E E D I N G S

CHAIR MITCHELL: All right. Let's go back on the record, please. And we are with Commissioner McKissick and his questions for the Duke witnesses.

MS. DOWNEY: Chair Mitchell, before we get started, if I may be recognized? Dianna Downey.

CHAIR MITCHELL: You may, Ms. Downey.

MS. DOWNEY: Chair Mitchell, during the break -- I'm hearing a lot of echo. I'm sorry.

CHAIR MITCHELL: Commissioner McKissick, you may need to -- okay.

All right. Proceed, Ms. Downey.

MS. DOWNEY: My apologies, but during the break, my accountants rightfully pointed out to me that I overpromised, at least based on what I heard during the proceeding earlier, and that there are a number -- that we need additional guidance as to some of the parameters around the document and the schedule that Commissioner Duffley asked. But rather than take up hearing time at this time to ask for clarification, if it's okay with the Chair, we would like to file a letter asking for those --

for that guidance, and we'll respond accordingly.

CHAIR MITCHELL: All right. Ms. Downey, that is -- that sounds like a good approach. Commissioner Duffley, as long as that approach works for you.

COMMISSIONER DUFFLEY: That does work for me. Or we could just have -- if it's acceptable to all the parties, you could call Commission staff, the legal staff working on the case, but either way.

MS. DOWNEY: Whatever your preference, just let us know.

COMMISSIONER DUFFLEY: I'll leave it to you, Chair Mitchell.

CHAIR MITCHELL: All right. Ms. Downey, why don't you just file your request in the docket, and we will respond accordingly.

MS. DOWNEY: Thank you, Chair Mitchell.

CHAIR MITCHELL: Thank you. All right.

Any additional administrative or housekeeping matters to attend to before we resume with Commissioner McKissick?

(No response.)

CHAIR MITCHELL: All right. Hearing

none, Commissioner McKissick, it's with you.

COMMISSIONER McKISSICK: Thank you, Madam Chair. I guess I was asking a few questions with Mr. De May, so I'll continue with those.

Whereupon,

STEPHEN G. DE MAY AND LARRY E. HATCHER,

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

CONTINUED EXAMINATION BY COMMISSIONER McKISSICK:

Q. Of course, Mr. Hatcher, if at any point you want to chime in, certainly feel free to do so.

I know, Mr. De May, when Commissioner Duffley was discussing the idea of rate fatigue, one of the things you brought up was, you know, multiyear ratemaking authority. I did not know if, at this point in time, it was the intention of either Duke Carolinas -- or the Duke entities, I should really say, because they should both think about it as a potential -- to pull together stakeholders to work through the issues and challenges that multiyear ratemaking presents. That might clarify and provide answers to some of the concerns that were raised last year when this was considered.

COMMISSIONER GRAY: Mr. De May, would

you unmute, please.

THE WITNESS: (Stephen G. De May) Sorry about that. I mentioned multiyear rate planning as an illustration of a way to address rate case fatigue. There are many ways to do so. You asked are we considering ways of addressing or exploring the opportunity with stakeholders; and I am pleased to say that the Clean Energy Plan process that is underway right now has two very important tracks associated with it. One is a climate policy track, and the other is a regulatory mechanisms track where the group -- and it's a large group of stakeholders, but all the important stakeholders are at the table. We are evaluating decoupling -- things like decoupling, multiyear rate plans, performance-based ratemaking, and the like.

So I'm very happy to say that a lot of work is going on in that space right now. So while I mention this as an example, and I also mention it as an example of the importance of the right inclusion and the way to role things out and so on, we are in a much different place and in a much better process right now. You're on mute.

Q. What is the timeline for that to -- for that group to try to reach some sort of consensus as opposed to this being relatively open-ended?

A. Well, it's definitely -- while it may technically be open-ended, the regulatory mechanisms part, I can't imagine it's going to go on much beyond, say, the early part of next year for two reasons. One is the first track, the climate policy track posed the governor a report by the end of the year. We expect that that report will not just address climate policy issues, it will include regulatory -- a discussion of regulatory mechanisms that will help the state achieve its climate objectives.

But I think importantly, this group of stakeholders is not one to sit on this discussion for long. There's going to be no dillydallying, I can promise you. And I expect that the report to the governor at the end of the year will include some recommendations to explore further those mechanisms.

Q. And one other issue that has emerged, you know, in the last year or so. I mean, there was authority given for securitization for storm-related costs and expenses. Has there been a thought given to expanding securitization for other areas that might be appropriate outside of just storm-related costs?

A. Yes. Yes. I would say of securitization, as the former treasurer of the Company, and I actually led the transaction -- securitization transaction for our Crystal River 3 nuclear river plant in Florida. It is an extremely complex tool, but it is an extremely effective one. But it has limited utility, I should say.

The Company cannot -- first of all, it has to get new legislation; secondly, a company can only avail itself of so much securitization, because securitization is a binding imposition of a cost on customers. Nothing can change it. No Commission can change it. Really, the legislature can't even change it. So once it's set, it's a binding commitment. And if you just start piling up these binding commitments, it takes flexibility away from the Commission, for instance, to do things in a more creative sense, expanding amortization periods and the like.

And so securitization has that limitation. Securitization also has the limitation, though, of eliminating the return that investors were getting on their capital. It is true that a securitization returns that capital instantly, the unamortized capital back to the investor or back the Company, but the ability to redeploy those kinds of proceeds is not always an easy thing to do.

So securitization comes with some complexities. It is a tool that has been used for storms, it has been used for stranded assets, but not a great deal more than that. And I see the opportunity to use that tool again in our future. But I wouldn't say -- oh, and I would add, sorry, that securitization is also a topic of discussion at the Clean Energy Plan table.

Q. Another area of concern. I know that we have before us a plan for grid improvements, they're looking at, like, $2.3 billion or so over the next three years, which is pretty strong, pretty aggressive program. I know, when witness Oliver testified, I asked questions with him about, you know, if the engineering would be done in house or using outside services. He mentioned there would likely be both. I asked him about the way work would be performed, internal crews or whether you're bidding out some of this work.

We did not get into whether it would be public bidding or private bidding. And when I say public, you know, advertising it for people to submit bids, or whether it will be private where you went back to people you have utilized in the past, and just got competitive offers from different companies or providers of services.

But the thing that I did not hear anybody speak of is the extent to which, with such a substantial amount of money being spent in that area potentially, the utilization of what I would call firms that have been historically unutilized. Disadvantaged businesses as they might have once been known. And are breaking into segments, so that small businesses, regardless of their make-up, have a greater opportunity to get a portion of that work, particularly in a day and time where our economy is being burdened, small businesses in particular.

Can you share with me your thoughts on what plans Duke has, at this time, to really try to reach out and provide contracting opportunities to competent and qualified small businesses and historically unutilized businesses, providing this moves forward as it is proposed at this time?

A. Yes, absolutely. I can speak in a general -- in a general sense about our supply chain objectives. I can't speak specifically to the grid improvement plan. But I think what I'm about to say to you encompasses the grid improvement plan.

Back in June, the Company announced that it was launching Hire NC, which is a Commission kind of directed program, and that is something that we are very enthusiastic about, very excited about. It will push more of our supply chain spending to local companies, North Carolina companies, and diverse companies: women-owned companies, veteran-owned companies, minority-owned companies, and so on.

And we are -- kind of the nature of the program is that for investments greater than, I think it's $700 million, we are -- you know, it's kind of -- it's -- one of the protocols of the program is to include those kinds of firms in that work.

So we're really excited about that. But I also wanted to mention to you that it's not -- we didn't just start using those firms under the Hire NC program. For the past five years we have averaged $1 billion spend with the kind of firms you were describing. And, in fact, in 2019, it was kind of a high watermark; $1.6 billion was spent with those firms.

So I am pleased to say that I actually think we're ahead of the curve on this. And I would expect that segments of our grid improvement plan will be part of the Hire NC initiative.

Q. Thank you for that explanation and putting things in context. I know I have read and heard about what some other utilities are doing that are comparable to Duke. I had not read or heard as much about what Duke has done. But I think, to the extent to which significant efforts and substantial efforts could be made to continue to promote and enhance those opportunities, I think it would be for the greater good of the economy and for helping to build opportunities for those who have not had a chance to participate traditionally in that American economic mainstream.

Now, I guess the other questions I have, I guess, really perhaps are more appropriate for Mr. Hatcher. So, Mr. Hatcher, I guess in reviewing your direct testimony and in reviewing your rebuttal testimony, you spoke about a CX monitoring program and how it was developing data and analytics to improve delivery of service to customers.

So I'm wanting to know, what information have you actively obtained? And how has that data, that information obtained, been utilized to improve services? And is there any measurable index that you are using to measure success as a result of those programs or initiatives you've undertaken?

A. (Larry E. Hatcher) Yes, sir. So the CX monitor tool is a propriety survey that we developed in house back in 2018. And the reason we did that, we were looking at J.D. Powers as an indicator, but it's really an indicator of how we perform against southern utilities. And you don't get a lot of internal written feedback on why people score you the way they score you.

So the CX monitor survey was created to really see how customers received Duke Energy, and would they recommend Duke Energy to their friends and family, or would they not, and kind of what is the reason why. And there is an index to that, it's MPS 4 that we track internally. And we're kind of tracking that to see if we're improving on the areas that are raised as concern or if we're lacking.

In addition to that, we created a fast track 2.0 propriety survey, which is more of a transactional-based survey. So if we have one of our technicians go to a customer's home and perform a service, we can get immediate feedback off of that transaction. And it also gives us verbatims so we can understand how the customer -- why they rated us the way they rated us.

Another component of that is called a reflect survey, and we're doing the same types of feedback from our digital services and our call center services. So we could take all of that data, along with our customer complaint data, and we can really see the things that are frustrating customers as they move along their journey with us.

Some of the things that we've done with that, if you really look at the top three things, it's around billing and payment. So folks wanted their bill simplified so they can understand it better. They wanted more information and more control. So if you look at what we're doing with AMI and the information that's being provided to the customer, you know, we're meeting that need from that respect. If you look at the other options the AMI is giving the customer around pick your own due date, start/stop service, making things easier for the customer, we're seeing positive feedback there. The -- they want more flexible payment arrangements. So if you look at that -- what we've done with our COVID response, a lot of the feedback that we received from customers, we applied in our

COVID response.

The other area that we heard loud and clear from our customers is they want us to communicate better with them, especially around outages. How long are we going to be without power? When is my power going to be back on, not necessarily my neighbors? So AMIs help us in that space. The tool, itself, has helped because we can communicate more directly with the individual customer. We can send them pictures of the damage, we can show them where it's located, we can send them another picture when the crews arrive. It keeps them updated along the way so they're not wondering what's going on.

And the last piece of that is really around the outage experience. And what our customers are telling us is that they recognize they're going to have outages due to the major storms, but they want us to recognize that and figure out ways to minimize those impacts and really get faster on the response and restoration. So, hence, what you're hearing in the testimony of Mr. Oliver is addressing a lot of that.

Q. Okay. Now, it sounds as if, as you said, it was a propriety system, you've used it in house, and it's helped a great deal.

Do you ever use outside firms or consulting firms that might help in doing similar type of analysis and comparative analysis comparing what your performance is at Duke compared to other comparable utilities to try to get some sense as to where you are in terms of a national performance if -- you know, if you can speak to that?

A. Sure. So J.D. Powers is our major source of data, in terms of how we're performing against our industry peers across the country. We also do consortiums with like my peers, where we talk about what's working for them and what's working for us, and we share ideas back and forth. And periodically we'll do benchmarking with another utility that we hear is doing something really well. We'll go visit them to learn about what they're doing and vice versa. So yes, sir.

Q. Okay. And can you point to any things that you've learned from that or any enhancements or changes that you made?

A. So one of them is the fee-free credit and debit card program that is, you know, part of this rate case.

Q. Right.

A. We've gotten a lot of feedback from our customers that they want this, they're very frustrated that they have to pay a fee. And we've also gotten the same feedback when we did benchmarking with some of the other utilities. So, hence, we're bringing that one forward, you know, to eliminate the customer concern. That would be one example.

Q. In your testimony, you also refer to something known as a Ping It program and what that constituted, as well as discussing additional efforts you were utilizing to communicate with customers using social media. So can you address those two issues?

A. Sure. So Ping It is a part of the AMI technology that we can actually send a signal from our control center to that meter to determine if that meter is active, and it's powered up, and there's power at the home or not. So it's a quick way for us to be able to determine the status of a customer's electricity, so to speak. So it's really a new improved technology versus our old meters that used to be in the homes where you have to roll a truck just to determine, you know, if the meter was operational or not operational.

In terms of some of what we're doing in social media and other ways to communicate with customers, we have drastically improved our website. We've done kind of a web refresh starting back, I believe, it was in 2015. We've had quite a few updates to that over the years. We're being able to give customers a lot more self-serve options so they don't necessarily have to call the call center to start or stop service. They don't have to call the call center to make a payment, so they can do all that online. There's other services that they can go out there and self-serve, versus having to wait on the phone to be able to talk to an agent.

We are using social media a lot with our customers who we have email accounts for or phone numbers to be able to send information. If we need to send them a notice about a proactive outage that we're taking for some reason, we can do that in advance so they're aware of that. If we need to send them information related to a potential bill change, we do that in advance so it's not a surprise. Those types of things, where we're able to communicate with our customer in, kind of, a more individual and more directly than we have been in the past.

Q.   And I guess my last question deals with sustainability, and in terms of -- I guess what -- I know in your testimony you talk about what I call a corporate sustainability goal, or sustainability that are being pursued, that are being implemented, and initiatives that are being undertaken to obtain them.

Can you speak to those in a more discrete way?

A. I'll give a shot at it. Before I do that, you asked for some tangible results or scores.

Q. Yeah.

A. I'll give you a little bit of that out of our fast track surveys. If you just look at DEC alone for start/stop service, 86 percent of our customers are satisfied with their experience with us for start/stop service. If you look at outage restoration, 81 percent of our customers have been satisfied with how we responded to outages. And then streetlight repairs is another key area that we've gotten a lot of feedback on. 73 percent of our customers are satisfied with their experience for streetlight repair. So maybe that would give you a little bit of tangible data, have some context for that service.

In terms of sustainability, the Company -- I'm really proud of what the Company is doing in terms of our sustainability goals and how those goals are in alignment with what you see out of climate change. And if you look at really goal 7 and goal 13 of the climate looking forward, we're really in alignment with those goals. So it's around affordable and clean energy as well as protecting the planet and climate action.

So if you think about just what we've done over the last several years since 2005, a 39 percent reduction in carbon emissions by the way we manage our fleet; think about our solar development, we're the second largest solar capacity in the country behind California; you look at what we're doing in terms of battery storage and the plans for battery storage going forward over the next 15 years, 375 megawatts of battery storage; and then with our plan to be at 50 percent carbon reduction by 2030, I think it just speaks to a lot of what Steven has talked about and what was in our IRP and what we've been doing to really improve, you know, our sustainability going forward.

Q. Thank you for those responses, and I hope, as we move forward with the IRP, that we will really work in a very concrete way to move forward the sustainability goals.

And I guess the last thing -- and perhaps neither of you are the best witness to speak to it, but how would, say, accelerated depreciation of the coal-fired generating plants help us get closer to that? And if we did not have it, what would the impact be?

A. (Stephen G. De May) So I'll take a stab at that. So we believe that nothing is more -- well, this is an exaggeration, perhaps, but we think the accelerated or the end of coal-fired generation in North Carolina is extremely foreseeable. And we think that we should be dealing with something so foreseeable at this point in time. An accelerated depreciation of this fleet would allow us to match the expected life of the asset to the expected depreciation rate, and it would also help us avoid a stranded asset situation, which is really not good for any stakeholder, at the end of their useful lives.

So we believe that the accelerated depreciation of this, of the coal fleet, carries those virtues, and we support it very strongly.

COMMISSIONER McKISSICK: Thank you, Madam Chair. I don't have any further questions.

CHAIR MITCHELL: I believe, Commissioner Clodfelter, you had an additional question?

COMMISSIONER CLODFELTER: Sure. Thank you, Madam Chair. I'm going to pile onto the request that Commissioner Duffley made, and if it sounds like a conspiracy, well, it sounds like whatever it is.

In addition -- for the Company and for Ms. Downey, in addition to the analysis of the -- on the revenue requirement effective off -- using some of the EDIT to offset some of the coal ash costs requested in this case, I'd like to see a second scenario; and what happens to the revenue requirement if some portion of the EDIT were used to offset in what I call the Crystal River matter, to offset the accelerated retirement of the coal plants as proposed by the Company in the case.

So how would the revenue requirement change, if at all, if some of the EDIT were used to offset the additional depreciation expense to retire those coal plants in the schedule the Company is now proposing? That would be scenario number two.

CHAIR MITCHELL: All right. Thank you, Commissioner Clodfelter.

All right. We will take questions on

the Commissioners' questions beginning with the Public Staff.

MS. DOWNEY: No questions.

CHAIR MITCHELL: All right. Attorney General's Office?

MS. FORCE: No questions. Thank you.

CHAIR MITCHELL: Any additional intervenors have questions on Commissioners' questions?

MR. PAGE: Chair Mitchell, if I may, please.

CHAIR MITCHELL: Mr. Page, you may proceed.

EXAMINATION BY MR. PAGE:

Q. Again, this is for Mr. De May. I think I understood you to say, in response to some of Commissioner Clodfelter's earlier questions that in the process to come, between this rate case and the next Duke rate case, there's going to be a fairly deep dive into the areas of cost of service studies and rate design; and that in that process, Duke welcomes the input of all stakeholders. Did I correctly understand that?

A. (Stephen G. De May) If you're referring to the low-income collaborative -- we have a couple of things going on. I'm not sure which one you were referencing. But at one point in time, I was talking about the low-income collaborative, where we would be looking at all kinds of measures that will achieve structural change in support of low-income customers. That could include rate design and cost of service-type enhancements or changes.

I didn't mention, but I have an opportunity to now, that we are conducting a rate design study as a company, and we will be doing that over the next year or so. There'll be more said about that by witness Lon Huber on the rate design panel.

Q. I guess to get directly to the point, I represent a pretty good-size stakeholder, and we would like very much to be a part of whatever conversations Duke is willing to entertain in those areas of cost of service and rate design between now and the next case. Is Duke willing to do that?

A. Of course we are. It's supposed to be a stakeholder-led process.

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

CHAIR MITCHELL: All right. Additional questions on Commission's questions?

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

CHAIR MITCHELL: Mr. Neal, you may proceed.

MR. NEAL: Thank you.

EXAMINATION BY MR. NEAL:

Q. Good afternoon, Mr. De May. I'm David Neal representing the North Carolina Justice Center, et al.

How are you doing this afternoon?

A. I'm well. Thank you, Mr. Neal.

Q. Good. The first follow-up on some questions raised by Commissioner McKissick regarding the sustainability goals.

You would agree, would you not, that improving the grid's ability to integrate clean renewable energy resources is an important part of achieving the Company's and the state's carbon reduction goals?

A. I would agree with that.

Q. Would you agree that the elements of the grid improvement plan reflected in the second settlement with the Public Staff and in the settlement with my clients and the North Carolina Sustainability Energy Association include elements of the grid improvement plan that will facilitate integration of clean renewable energy?

A. In fact, the amount of the grid improvement plan that was settled upon is almost exclusively the integration distributed energy resources. There's some cyber investment there as well, but yes.

Q. And now turning to some follow-up questions from Commissioner Clodfelter's questions around affordability.

Did you have the chance to observe -- Mr. De May, did you have the chance to observe John Howat's live testimony in the consolidated hearing dockets earlier this week?

A. Most of it, yes.

Q. And have you had a chance to -- have you had a chance to review his prefiled testimony?

A. I did skim it, I would say.

Q. Would you agree that Mr. Howat has a depth of experience on utility affordability at low-income rate design issues?

A. Certainly I would acknowledge he has experience and certainly a passion.

Q. And do you recall that Mr. Howat supported your call to use a collaborative stakeholder process to be overseen by the Commission before initiating any new low-income programs, including new low-income rate designs?

A. I do.

Q. Mr. De May, are you familiar with the Helping Home Fund?

A. I am.

Q. And would you agree that the Company's contributions to the Helping Home Fund have provided material improvements to the homes of participating low-income customers?

A. I would agree with that; and the Company is pleased to be a participant in those gifts.

Q. And did you hear Mr. Howat's support for the Company's settlement with my clients and the Sustainable Energy Association, including the Company's commitment to contribute an additional $6 million towards the Helping Home Fund and to develop new low-income energy efficiency programs as steps that would be important to improve affordability in the short term?

A. Yes.

Q. And I take it you would agree with his statements?

A. With his statements?

Q. Yes.

A. I didn't agree with all of his statements.

Q. I'm sorry, to be clear, agree with his statements in support of the settlement.

A. I agree with those statements.

MR. NEAL: Thank you, Chair Mitchell. No further questions.

CHAIR MITCHELL: All right. Thank you, Mr. Neal.

Any additional questions from the intervenors on the Commissioners' questions?

(No response.)

CHAIR MITCHELL: All right. Duke. Any questions from Duke?

MR. ROBINSON: Yes, Chair Mitchell, I just have a few, and these are specifically to Mr. De May.

EXAMINATION BY MR. ROBINSON:

Q. Mr. De May, do you recall a discussion you had with Commissioner Duffley when the topic of run rates was brought up?

A. (Stephen G. De May) Yes.

Q. Mr. De May, did the Company recently file a late-filed exhibit that dealt with run rate issues?

A. Yes.

Q. Did you have a chance to review that exhibit?

A. Yes, I did.

Q. Can you describe the exhibit and the major conclusions you draw from it?

A. Yes, I'd be happy to. Thank you. So the exhibit was borne from a request of Commissioner Duffley who asked if we would do a pro forma analysis of what our FFO metric in 2019 would have been had we been awarded a run rate in the rate -- the 2018 rate order. And schedule A in that exhibit describes that calculation, that analysis. And I want to just point out a few things to think about as you consider schedule A.

One is the run rate was requested for and is always contemplated to be a recovery of costs on a prospective basis. So we were not seeking to recover historic spend with a run rate. And so, in 2018, had the order approved a run rate and we were looking to adjust the 2019 FFO metric, we simply changed the treatment of 2019's coal ash costs from a capital-like treatment and called it more of a period expense. And in so doing, we adjusted the metric.

And the way that occurs is coal ash, when it's being capitalized and deferred, is not part of our FFO numerator. It is not an operating cash flow item because it has been treated like capital. And so we have to then add that back in because a run rate implies that it's no longer being treated like capital. So we added that cost to FFO and reduced it.

But then the way a run rate would work, we would increase the revenues to FFO to reflect the allowed run rate.

And so you can see on schedule A -- we'll just look at DEC -- that once the Commission -- once the Commission would make the move from capital treatment to O&M, or an operating cost, then the rating agency would treat all coal ash expenditures as an operating expense. And therefore, we took out $278 million. We put in 201, because that was the 2017 run rate. And you can see that, while we are able to recover through the run rate revenues, a good bit of the total coal ash spend, we didn't recover all of it. And therefore, you can see its relatively modest reduction in the FFO-to-debt calculation.

So there are three lessons, I would say, that you can take away from that one exhibit. One is the test year does not necessarily equal future spend. I know that's intuitive, but you have to set a run rate that approximates the coal ash spend that you expect to incur if you want that metric to be supported. The other thing I would say is that the coal ash -- when the rating agencies change their view of this as a result of moving to a run rate, they're going to take systemwide coal ash costs and put them back as a deduction to FFO. Systemwide. But, of course, this Commission would only be able to grant a run rate on the North Carolina retail portion. So there will be South Carolina components, there will be wholesale components.

We -- so those -- again, not necessarily the purview of this Commission but just for context. It will be hard for a run rate to completely offset the change in treatment by the rating agencies, but you can get close.

The third is that, you know, that mismatch that I'm describing to you, the mismatch you see here in this pro forma calculation, creates a bit of lag in and of itself. And you would have to establish some kind of deferral mechanism to where undercollections are dealt with or overcollections are dealt with.

So we -- this was a -- in response to Commissioner Duffley's request, but if I could take you to schedule B for a moment, the Company went a step further. Because it's important to understand the trade-offs of the different recovery mechanisms.

And I want to start with the predicate that coal ash is a recoverable expense. You have to start there to embrace this table and the calculations that we're making here. If coal ash is accepted as a recoverable cost, then it is either in current expense being paid for by current revenues, or it is a current expense being deferred as a deferred expense and then recovered over time by a Commission decision in a future rate hearing, or is treated as a capitalized regulatory asset that will actually function very similar to the deferred cost.

And so one of two things has to happen in order for the Company to recover its costs -- its prudent costs. Let's just make that assumption as well. That it is either receiving recovery in the period of expense, or if it's being deferred or capitalized, then it has to receive a return as well to compensate for these -- of shareholder funds.

And so I want to just quickly just say what this table does. And with the first column -- we might should have reordered these columns, but the first column and the fourth column, they're numbered, are taking the existing treatment of coal ash from the 2018 order to DEC and to DEP. In the first column is exactly the same treatment with the five-year flow -- return and recovery. The fourth column is an extension of that recovery period from 5 years to 10 years. And that is merely taking the request of, you know, effectively what's in this rate case today and applying the current treatment with a different amortization period. And you can see that what's intuitive is the longer amortization period has a mitigating impact on customer rates. It's just like taking a 15-year mortgage and refinancing it to a 30-year mortgage. You're getting that benefit of a longer period of time.

But what happens in columns 2 and 3 is the run rate concept. And the run rate works for prospective costs, but you still have to deal with the historic costs. And what this table shows is, not only are we recovering the current ask through the column 1 mechanism, five years, but we're also adding a run rate for future costs.

Column 2's run rate is a 2018 test year;

column 3's run rate is an average of a future five years. That's the difference between those. But there is almost no difference between the 28-test-year spend and the 21 to 25 average spend.

And so the story really isn't a comparison between column 2 and 3, they just happen to be very close in scale. The story here is that a run rate will be -- is an effective way to recover coal ash costs and -- but it will have a dramatically stronger impact to customer rates than the ability to defer or capitalize these costs and set them for recovery at a future date. And even with the return, which we believe these deserve, that will be less impactful to customer rates than the run rate.

But importantly, either is a reasonable mechanism for achieving timely recovery. Column 1 is more timely than column 4, and -- excuse me, column 2 and 3 are more timely than column 1 and 4; column 1 is more timely than column 4. You get the point I'm trying to make here.

But there is a series of trade-offs here, and we just wanted the Commission to appreciate and understand that, if you start with that predicate I suggested, that coal ash is recoverable, and if it is using shareholder funds, in other words, not being recovered in the period it was incurred, then the -- you know, the current mechanism is probably the most effective.

In the last -- in the 2018 order, the Commission said that we were to continue to defer our costs, that they would be evaluated at the next rate case, and barring any imprudent costs -- again, I just want to say, for the sake of argument, assume all imprudent costs -- then we would be allowed to recover these with the return during the amortization period, and the Commission will set the amortization period. And we wanted you to see that a 5-year return and a 10-year return are both credit support to the Company.

So hopefully you were able to follow some of those lessons I think we were trying to convey from this analysis.

Q. Thank you.

MR. ROBINSON: I have no further questions.

CHAIR MITCHELL: All right. I would, at this point, entertain motions from the parties.

MR. ROBINSON: Chair Mitchell, only motion I have is I move to excuse

Mr. Larry Hatcher.

CHAIR MITCHELL: All right. Hearing no objection, Mr. Robinson, Mr. Hatcher, you may step down. Thank you very much for your testimony today.

MS. FORCE: Madam Chair, I think --

CHAIR MITCHELL: I'm sorry. And just one -- I believe, Ms. Force, you were about to move your exhibits in, but I will allow Mr. De May to step down as well for the time being.

THE WITNESS: (Stephen G. De May) Thank you, Chair Mitchell.

CHAIR MITCHELL: Thank you, Mr. De May. We appreciate your testimony today.

THE WITNESS: You're welcome. Thank you.

CHAIR MITCHELL: All right, Ms. Force.

MS. FORCE: Madam Chair, the Attorney General moves the admission of AGO Hatcher Cross Exhibits 1 through 5.

CHAIR MITCHELL: Thank you, Ms. Force. Hearing no objection to your motion, it's allowed.

(AGO Hatcher Cross Exhibits 1 through 4 were admitted into evidence.)

(AGO Hatcher Cross Exhibit 5 was previously admitted in Volume 11.)

MR. TRATHEN: Madam Chair, Marcus Trathen for Tech Customers. I would also move into evidence De May Tech Customers Cross Exhibit 1.

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

(De May Tech Customers Cross Exhibit 1 was admitted into evidence.)

MS. TOWNSEND: Chair Mitchell, Terry Townsend for the AG's office. I also would like to move into evidence the AGO Exhibit -- I'm sorry, De May AGO Exhibit 1 [sic].

CHAIR MITCHELL: All right. Ms. Townsend, hearing no objection, your motion is allowed.

MS. TOWNSEND: Thank you.

(AGO De May Cross Exhibit 1 was admitted into evidence.)

CHAIR MITCHELL: All right. At this point, we will -- we are still with Duke. You may call your next witness.

MR. ROBINSON: Chair Mitchell, before we do that, if we could have just a minute to be able to get Mr. Immel into the room for him to testify.

CHAIR MITCHELL: All right. Thank you, Mr. Robinson. Let's take a five-minute recess to allow the witnesses to switch places. We will be off the record, and let's go back on at 2:26.

MR. ROBINSON: Thank you, Chair.

(At this time, a recess was taken from 2:21 p.m. to 2:26 p.m.)

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

Duke, we're with your witness. You may call him.

MS. KELLS: Thank you, Chair Mitchell. This is Andrea Kells appearing on behalf of Duke Energy Carolinas, and the Company now calls Mr. Steve Immel.

CHAIR MITCHELL: Good afternoon, Ms. Kells.

Mr. Immel, let's go ahead and get you under oath, please, sir.

Whereupon,

STEVE IMMEL,

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

CHAIR MITCHELL: Thank you very much.
Ms. Kells, you may proceed.

DIRECT EXAMINATION BY MS. KELLS:

Q. Mr. Immel, would you please state your name and business address for the record.

A. Steve Immel, 526 South Church Street, Charlotte, North Carolina.

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

A. Employed by Duke Energy. I'm the vice president of fleet transition strategy. At the time of my direct testimony and rebuttal testimony for this hearing, I was actually the vice president of the Carolina coal generation fleet.

Q. Did you cause to be prefiled in this docket on September 30, 2019, 12 pages of direct testimony?

A. I did.

Q. And did you also cause to be prefiled in this docket on March 4, 2020, 19 pages of rebuttal testimony?

A. I did.

Q. Do you have any changes or corrections to either of those testimonies?

A. I do not. No changes.

Q. And if I were to ask you the same questions that appear in your direct and rebuttal testimonies today, would your answers be the same?

A. They would be.

Q. Mr. Immel, did you prepare a summary of your direct and rebuttal testimonies?

A. I did.

MS. KELLS: Chair Mitchell, at this time, I move that the prefiled direct and rebuttal testimonies of Mr. Immel and his summary of his direct and rebuttal be copied into the record as if given orally from the stand.

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

(Whereupon, the prefiled direct and rebuttal testimony, as well as the Summary of Steve Immel were copied into the record as if given orally from the stand.)

I. INTRODUCTION AND OVERVIEW

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steve Immel and my business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am Vice President of Carolinas Coal Generation for Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and Duke Energy Progress, LLC ("DE Progress").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from the University of Kentucky with a Bachelor of Science degree in Civil Engineering and a Masters of Business Administration from Queens College. My career began with Duke Energy (d/b/a Duke Power) in 1980 as an Associate Design Engineer. Since that time, I have held various roles of increasing responsibility in corporate facilities, investment recovery, supply chain, and operations areas, including the role of Hydro Manager; Station Manager at DE Carolinas' Allen Steam Station and then Marshall Steam Station. I was named Vice President of Duke Energy Indiana's Midwest Regulated Operations in 2012 and Vice President of Outage and Project Services in 2014. I assumed my current role in 2016.

Q. WHAT ARE YOUR DUTIES AS VICE PRESIDENT OF CAROLINAS COAL GENERATION?

A. In this role, I am responsible for providing event free and reliable operations of the coal generation fleet, which includes six coal stations, serving North Carolina and South Carolina by providing approximately 10,000 megawatts ("MWs") of generation capacity. My responsibilities include operating and maintaining the fleet within design parameters and implementing safe work practices and procedures to ensure the safety of our employees.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER REGULATORY BODIES IN ANY PRIOR PROCEEDINGS?

A. I have not previously testified before this Commission. However, I provided testimony before the Public Service Commission of South Carolina on behalf of the Company in its most recent general rate case in Docket No. 2018-319-E.

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

A. The purpose of my testimony is to support DE Carolinas' request for a base rate adjustment. My testimony will describe the Company's Fossil/Hydro/Solar generation assets and update the Commission on capital additions. Since its last rate case, DE Carolinas has upgraded its generating facilities to serve customers. In addition, I provide operational performance results for the period January 1, 2018 through December 31, 2018 ("Test Period"), and explain the key drivers impacting operations and maintenance ("O&M") expenses.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized as follows:

II. FOSSIL/HYDRO/SOLAR FLEET

III. CAPITAL ADDITIONS

IV. O&M AND OTHER ADJUSTMENTS

V. PERFORMANCE

VI. CONCLUSION

II. FOSSIL/HYDRO/SOLAR FLEET

Q. PLEASE DESCRIBE DE CAROLINAS' FOSSIL/HYDRO/SOLAR GENERATION FLEET.

A. The Company's Fossil/Hydro/Solar generation portfolio consists of approximately 14,992 MWs of generating capacity, made up as follows:

Coal-fired -	6,764 MWs
Steam Natural Gas -	170 MWs
Hydro -	3,245 MWs
Combustion Turbines -	2,665 MWs
Combined Cycle -	2,116 MWs
Solar -	31 MWs

The coal-fired assets consist of four generating stations and a total of 13 units. These units are equipped with emissions control equipment, including selective catalytic or selective non-catalytic reduction ("SCR" or "SNCR") equipment for removing nitrogen oxides ("NO_x") and flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"). The

Rogers Energy Complex ("Cliffside") and Belews Creek Unit #1 have the ability to burn natural gas and coal at both units.

The steam natural gas unit – W.S. Lee Station Unit 3 – is considered to be a peaking unit. The Company has a total of 31 simple cycle combustion turbine ("CT") units, of which 29 are considered the larger group providing approximately 2,581 MWs of capacity. The 29 units located at the Lincoln, Mill Creek and Rockingham Stations are equipped with water injection systems that reduce NO_x and/or have low NO_x burner equipment in use. The W.S. Lee CT facility includes two units with a total capacity of 84 MWs equipped with black start ability that can support DE Carolinas Oconee Nuclear Station.

The Buck CC, Dan River CC and W.S. Lee CC facilities represent 2,116 MWs of combined cycle ("CC") generation. These facilities are equipped with technology for emissions control including SCRs, low NO_x combustors, and carbon monoxide/volatile organic compounds catalysts.

The Company's hydro fleet includes two pumped storage facilities with four units each that provide a total capacity of 2,140 MWs, along with conventional hydro assets consisting of 72 units providing approximately 1,105 MWs of capacity.

The 31 MWs of solar capacity consist of 18 roof top solar sites providing 3 MWs of relative summer dependable capacity, the Mocksville solar site providing 5 MWs of relative summer dependable capacity, the Monroe solar site providing 21 MWs of relative summer dependable capacity, and the Woodleaf solar site providing 2 MWs of relative summer dependable capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FLEET SINCE THE 2017 RATE CASE?

A. The Hydro Fleet retired the Rocky Creek Station and four units at Great Falls in May 2018 and two units at Ninety-Nine Islands in December 2018. Cliffside Station and Belews Creek Unit #1 were upgraded to allow for co-fired operation, allowing utilization of coal and natural gas. DE Carolinas completed the Woodleaf solar facility in December 2018. This facility has 6 MWs of nameplate capacity, which provide 2 MWs of relative summer dependable capacity. DE Carolinas also entered into an agreement whereby the Company sold five hydro generating stations to Northbrook Carolina Hydro II, LLC and Northbrook Tuxedo, LLC. The facilities have a combined 18.7-MW generation capacity and consist of the Bryson Hydro station, the Franklin Hydro station, the Mission Hydro station, the Tuxedo Hydro station, and the Gaston Shoals Hydro station. Four of the facilities are located in North Carolina, and the fifth is located in South Carolina.

Q. WAS THE CHANGE IN OWNERSHIP OF THE HYDROELECTRIC GENERATING FACILITIES APPROVED BY THIS COMMISSION?

A. Yes. The Hydroelectric Generating Facilities sale was approved in Docket Nos. E-7, Sub 1181; SP-12478, Sub 0; and SP-12479, Sub 0.

III. CAPITAL ADDITIONS

Q. PLEASE DESCRIBE THE MAJOR FOSSIL/HYDRO/SOLAR CAPITAL INVESTMENTS COMPLETED SINCE THE COMPANY'S LAST RATE CASE PROCEEDING.

A. Since the previous rate case, the Company has made capital investments in its Fossil/Hydro/Solar fleet to continue to provide safe and reliable generation for customers. For example, the Company has made significant investments within its coal fleet to meet environmental regulations to allow for the continued operation of active plants, including the Coal Combustion Residual ("CCR") Rule, the Coal Ash Management Act ("CAMA") and Effluent Limitations Guidelines ("ELG"), totaling approximately $689 million, largely driven by dry bottom ash conversions, wastewater treatment enhancements, and lined retention basins projects.

The Company also converted Cliffside Station and Belews Creek Unit 1 to have the capability to burn natural gas and coal. Cliffside Unit 5 can now burn up to 40% natural gas and Cliffside Unit 6 is able to burn up to 100% natural gas. Belews Creek Unit 1 will be able to burn up to 50% natural gas. This co-firing capability allows the Company to utilize the most cost-effective fuel, providing the Company with fuel flexibility for the benefit of customers.

Q. ARE THESE CAPITAL INVESTMENTS USED AND USEFUL IN PROVIDING ELECTRIC SERVICE TO DE CAROLINAS' ELECTRIC CUSTOMERS IN NORTH CAROLINA?

A. Yes. The conversion of Cliffside Station and Belews Creek Unit 1 provides customers with flexibility to utilize the most cost-effective fuel. The compliance efforts and the conversion of Cliffside Station and Belews Creek Unit 1 are used and useful, providing customers reliable low-cost generation. The capital investments position the Company to provide safe, reliable, and efficient operation of these assets, with high quality performance.

Q. IN YOUR OPINION, HAVE THE COSTS RELATED TO THE COMPANY'S CAPITAL ADDITIONS BEEN PRUDENTLY INCURRED?

A. Yes. The Company controls costs for capital projects and O&M using a cost management program. The Company also controls costs through routine executive oversight of project budget and activity reporting with new projects requiring approval by progressively higher levels of management depending on total project cost. Further, the Company controls ongoing project and O&M costs through strategic planning and procurement, efficient oversight of contractors by a trained and experienced workforce, rigorous monitoring of work quality, thorough critiques to drive out process improvement, and industry benchmarking to ensure best practices are being used.

Q. HOW DO CUSTOMERS BENEFIT FROM THE COMPANY'S INVESTMENTS FOR THE FOSSIL/HYDRO/SOLAR FLEET?

A. The Company's fleet investments have enabled it to continue to provide safe, efficient and reliable service to DE Carolinas' customers at least reasonable cost. These efforts have also reduced the Company's environmental footprint by adding state-of-the-art technology for reducing emissions, and expanding the use of natural gas generation at a time when the natural gas market is providing low prices.

IV. O&M AND OTHER ADJUSTMENTS

Q. PLEASE DESCRIBE THE O&M EXPENSES FOR THE FOSSIL/HYDRO/SOLAR FLEET.

A. For the fossil units, approximately 81 percent of DE Carolinas' required O&M expenditures are fuel-related for the Test Period. The majority of non-fuel expenditures are for labor costs from Company or contract resources that operate, maintain, and support the Fossil/Hydro/Solar facilities. Finally, the Company continues to be challenged by costs driven by inflationary pressures for labor and materials.

Q. HOW DOES THE COMPANY CONTROL AND MITIGATE O&M EXPENSE INCREASES? PLEASE PROVIDE EXAMPLES.

A. The Company has many efforts in place for controlling and/or saving costs. For example, DE Carolinas optimizes outages based on run time, which has been affected by changes in the gas market and new generation resources that further increased DE Carolinas' use of natural gas. This effort has provided savings with labor and material costs.

Duke Energy joined forces with other power companies to share best practices and learning opportunities with the Fossil Networking Group ("FNG"). The FNG includes Southern Company, Dominion Energy, American Electric Power and the Tennessee Valley Authority, who along with the Company, have seen tangible benefits in the areas of safety and operations.

The Company runs its business in a disciplined manner and continuously balances cost management with safety and reliability to provide generation to our customers. Cost to customers is a key concern and the Company's diverse portfolio allows us to reduce overall fuel expense and take advantage of low natural gas prices.

V. <u>PERFORMANCE</u>

Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR DE CAROLINAS' FOSSIL/HYDRO/SOLAR FLEET DURING THE TEST PERIOD.

A. The Company's Fossil/Hydro/Solar generating units operated efficiently and reliably during the Test Period. Several key measures are used to evaluate the operational performance depending on the generator type such as: (1) equivalent availability factor ("EAF"), which refers to the percent of a given time period a facility was available to operate at full power; (2) equivalent forced outage rate ("EFOR"), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); and (3) starting reliability ("SR"), which represents the percentage of successful starts.

The chart below provides operational results categorized by generator type, as well as results from the most recently published North American Electric Reliability Council ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") representing the period 2014 through 2018. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating. The data in the chart reflects DE Carolinas results compared to NERC five-year comparisons.

Generator Type	Measure	Review Period	2014-2018	Nbr of Units
		DEC Operational	NERC Average	
Coal-Fired Test Period	EAF	79.5%	77.3%	752
	EFOR	7.5%	9.3%	
2018 Summer	Coal-Fired EAF	95.8%	n/a	n/a
	Combined Cycle EAF	91.7%	n/a	n/a
Total CC Average	EAF	86.2%	84.9%	333
	EFOR	3.32%	5.1%	
Total CT Average	EAF	83.3%	87.5%	750
	SR	99.4%	98.3%	
Hydro	EAF	76.3%	80.2%	1,063

Based on operating performance data for 2017 that was published in the June 2018 issue of *Power Engineering* magazine, DE Carolinas' Rogers Energy Complex, Belews Creek Steam Station, and Marshall Steam Station ranked as the second, fourth, and eighth most efficient coal-fired generating stations in the nation with heat rates of 9,055 Btu/kWh, 9,167 Btu/kWh, and 9,495 Btu/kWh, respectively. These results compare favorably to the average heat rate of 10,476 Btu/kWh for North American coal generators, also reported in the above noted magazine.

Q. HOW MUCH GENERATION DID EACH TYPE OF GENERATING FACILITY PROVIDE FOR THE TEST PERIOD?

A. For the Test Period, DE Carolinas' system total generation was approximately 101.8 million megawatt-hours ("MWHs"). The Fossil/Hydro/Solar fleet provided approximately 41.8 million MWHs, or approximately 41 percent. The breakdown includes approximately 22 percent contribution from the coal-fired stations, 16 percent from gas facilities, and approximately 2 percent from renewable facilities, primarily hydro.

Q. IN YOUR OPINION, HAS DE CAROLINAS PRUDENTLY OPERATED ITS FOSSIL/HYDRO/SOLAR FLEET DURING THE TEST PERIOD?

A. Yes. The Company's performance data supports the conclusion that DE Carolinas has reasonably and prudently operated and maintained its Fossil/Hydro/Solar resources to maximize unit availability, minimize fuel costs, and provide safe and reliable service to its customers.

VII. CONCLUSION

Q. IS THERE ANYTHING YOU WOULD LIKE TO SAY IN CLOSING?

A. Yes. The Company has a proven history of experience-based, safe, quality, and cost competitive operations of a diverse generation portfolio. The Company has been active and diligent in its modernization efforts to ensure the right investments that continue, and build on, DE Carolinas' solid history of safely providing reliable, efficient, and cost-effective generation while reducing environmental impacts and ensuring compliance with state and federal regulations. The diversity of the Company's generation assets provides significant benefit to customers in an economic dispatch environment, especially with the natural gas market continuing to experience low prices. DE Carolinas is positioned to continue as a leader in the industry with a solid base of knowledge and experience. This base rate increase will allow the Company to continue the tradition of operational excellence and focus on safe operations and reliable generation.

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

A. Yes.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steve Immel and my business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am Vice President of Carolinas Coal Generation for Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and Duke Energy Progress, LLC ("DE Progress").

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

A. Yes, I did.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to: (1) Public Staff witness Metz's recommended disallowance of the Belews Creek Unit 1 dual fuel optionality ("DFO") project (the "Belews Creek Unit #1 DFO Project"); (2) Sierra Club witness Wilson's, Tech Customers witness Strunk's, and NC WARN witness Powers' recommended disallowances of the Company's capital investments in its coal fleet; and (3) additional Public Staff recommendations regarding collaboration with the Company on project documentation, and scheduling periodic independent third party audits of the Company's materials and supplies ("M&S") inventory and program controls.

III. BELEWS CREEK UNIT #1 DFO PROJECT RECOVERY

Q. PLEASE SUMMARIZE THE BELEWS CREEK UNIT #1 DFO PROJECT.

A. In January 2020, DE Carolinas completed its upgrade of the Belews Creek Unit #1 to allow for the utilization of coal and natural gas. The project scope included the installation of natural gas supply piping from the custody transfer point of the boiler, safety shutoff and vent valves, control system, and dual fuel burners.

Q. WHAT IS THE CURRENT STATUS OF THE BELEWS CREEK UNIT #1 DFO PROJECT?

A. On January 10, 2020, the DFO Project was put into service using a combination of gas and coal. On January 12, 2020, the generator cooling system, which is wholly unrelated to the DFO Project, required repairs and the unit was removed from service to complete those repairs. Those repairs were completed in early February and Unit #1 re-entered startup on February 20, 2020, to continue gas system testing, which extended until March 2, 2020. The Company anticipates Unit #1 testing to be successfully completed and the unit turned over to dispatch by March 20, 2020.

Q. WHAT IS THE BASIS OF WITNESS METZ'S PROPOSED DISALLOWANCE?

A. Witness Metz argues that the costs of the Belews Creek Unit #1 DFO Project should be disallowed because the project is not commercially operational and not available for economic dispatch.

Q. WAS WITNESS METZ'S CALCULATION OF THE APPROXIMATELY $81.8 MILLION DISALLOWANCE CORRECT?

A. No. Witness Metz's proposed adjustment included the costs of the ongoing DFO upgrade at Belews Creek Unit #2, which is not at issue in this case. Accordingly, notwithstanding the Company's position that Unit #1 was correctly placed in service, witness Metz's recommended disallowance should be reduced by approximately $13 million, to approximately $68 million on a system basis.

Q. DO YOU AGREE WITH WITNESS METZ'S DISALLOWANCE RECOMMENDATION?

A. No, I do not. The Belews Creek Unit #1 DFO Project was functionally tested in December 2019. As noted above, on January 10, 2020, the DFO Project was put into service using a combination of gas and coal. This was consistent with the Federal Energy Regulatory Commission ("FERC") Code of Federal Regulations ("C.F.R."), Electric Plant Instruction as discussed at pages 21-25 of the rebuttal testimony of Company witness David Doss. The unit operated continuously using natural gas from January 10, 2020, to January 12, 2020. Unit power generation to the grid during this period fluctuated between 300-500 megawatts ("MW") and the percent fuel mix in the boiler fluctuated.

Q. WHAT IS YOUR UNDERSTANDING OF THE PHRASE "USED AND USEFUL?"

A. I am not a lawyer but based on the input of counsel I understand that the North Carolina Utilities Commission ("Commission") has used the phrase "used and useful" in the context of power generation to mean that a plant is operational and serving its intended purpose of producing electricity. In my view the Belews Creek Unit #1 DFO Project clearly meets this standard.

Q. WHY DO YOU BELIEVE THE BELEWS CREEK UNIT #1 DFO PROJECT MEETS THIS STANDARD?

A. The project became used and useful when it went in-service on January 10, 2020 and serving its intended purpose of producing electric power that was provided to the Company's customers.

IV. REASONABLENESS AND PRUDENCE OF THE COMPANY'S CAPITAL INVESTMENTS IN ITS FOSSIL/HYDRO/SOLAR FLEET

Q. PLEASE REITERATE THE SCOPE OF THE COMPANY'S CAPITAL INVESTMENTS REFLECTED IN YOUR DIRECT TESTIMONY.

A. My direct testimony supports capital investments in the Company's Fossil/Hydro/Solar Operations ("FHO") fleet that the Company has made since its previous rate case in order to continue to provide safe and reliable generation for customers. One example of those investments is the approximate $689[1] million that the Company invested in its coal fleet to meet environmental regulations to allow for the continued operation of active coal plants. Another example is the conversion of Cliffside Station and Belews Creek Unit 1 to have the capability to operate on both natural gas and coal.

[1] As of January 2020, this amount is now approximately $694 million.

Q. DID THE PUBLIC STAFF RECOMMEND ANY DISALLOWANCE OF THE COMPANY'S REQUEST FOR RECOVERY OF ITS CAPITAL INVESTMENTS IN FHO BASED ON UNREASONABLENESS OR IMPRUDENCE?

A. No. The Public Staff conducted a thorough investigation of these investments. As witness Metz stated in his testimony, he "looked at multiple aspects of capital spend to evaluate them for reasonableness and prudence," and his investigation included review of not only direct testimony, but also an audit of specific expenditures, discovery, teleconferences with the Company, site visits and interviews with Company witnesses and staff, and review of overall projects with Company management.

Q. DID ANY OTHER PARTY RECOMMEND DISALLOWANCE OF THE COMPANY'S CAPITAL INVESTMENTS IN FHO SINCE THE PREVIOUS RATE CASE?

A. Yes. Sierra Club witness Wilson recommended disallowance of all the Company's capital expenditures made during the time between the 2017 rate case (Sub 1146) and the current case, "until DEC provides evidence of an analysis demonstrating the value of investment done at time investment decision made." Based on the substance of her testimony, I interpret witness Wilson's recommendation to be directed at investments in DE Carolinas' coal fleet. Tech Customers witness Strunk recommended the Commission "not allow inclusion in rate base of the incremental capital expenditures at Allen Units 4 and 5, and Cliffside Unit 5 between the prior rate case" and this case.

NC WARN witness Powers recommended disallowance of the Company's costs for the DFO conversion projects at Belews Creek Unit #1 and Cliffside.

Q. HOW DID YOUR DIRECT TESTIMONY SUPPORT THE COMPANY'S CAPITAL INVESTMENTS IN ITS COAL FLEET AS REASONABLY AND PRUDENTLY INCURRED?

A. Consistent with testimony provided in prior rate cases, my direct testimony explained that these capital investments are used and useful in providing electric service to the Company's customers as they provide customers reliable low-cost generation, and position the Company to provide safe, reliable, and efficient operation of these assets with high quality performance. I also testified that these costs have been prudently incurred and explained the various ways in which the Company controls project and O&M costs for capital projects. Finally, I noted how customers benefit from the Company's investments as they have enabled DE Carolinas to continue to provide safe, efficient, and reliable service to customers at least reasonable cost and reduced the Company's environmental footprint by adding state of the art technology for reducing emissions.

Q. WHAT OTHER EVIDENCE ARE YOU PRESENTING IN SUPPORT OF THESE PROJECTS?

A. In my rebuttal testimony, I provide additional support for these capital investments, including discussion of retirement studies and other analyses that the Company conducted in order to evaluate whether to make these investments, and provided through discovery in this case. I also address specific assertions made by intervenors with respect to the reasonableness and prudency of these investments.

Q. CAN YOU DESCRIBE THE SCOPE OF THE ADDITIONAL INFORMATION PROVIDED BY THE COMPANY THROUGH DISCOVERY?

A. Yes. Through discovery, the Company provided numerous narrative responses and voluminous documentation and analyses in support of the reasonableness and prudency of the Company's capital investments in FHO, including the capital investments specifically addressed by my direct testimony. Specifically, the Company provided:

- For all environmental capital projects with total project costs $1 million or more, initial and final budget and actual spend, timing of project (expected and actual), project description, and explanation of why each project was necessary;
- For all environmental capital projects with total project costs less than $1 million but more than $100,000, actual cost, completion date, and project description;
- Additional information for all environmental and certain other capital projects including proposal, bid, and contract information, funding approval documentation, detailed cost breakdowns, and risk registers;
- Detailed cost and operational information for the DFO conversion projects, including: completion dates, itemized cost breakdowns of each DFO project, coal and natural gas heat rate data and BTU values;

expectations for life of the projects; continued benefits of the Cliffside DFO projects considering the proposed early retirement of Cliffside Unit 5; explanation of changes in coal price forecasts and the impact of renegotiated rail service; original and updated cost benefit analyses; and explanation of related pipeline costs;

- Detailed annual historical and projected capital related spend for environmental compliance costs for Allen Station; discussion of continued minimally required maintenance to maintain the reliability of plants as they approach their retirement; discussion of reductions in annual O&M cost at Allen Station in recent years; and discussion of retirement analyses; and
- Information on specific environmental capital projects at Cliffside Station, including costs, capacity factor, and cost-benefit analyses.

Q. HOW DO YOU RESPOND TO TECH CUSTOMERS WITNESS STRUNK'S RECOMMENDED DISALLOWANCE OF INVESTMENTS MADE AT ALLEN UNITS 4 AND 5 AND CLIFFSIDE UNIT 5 SINCE DE CAROLINAS' PREVIOUS RATE CASE?

A. The Company studied the potential early retirement of Cliffside Unit 5 and Allen Station in 2016 and 2017, respectively. The retirement studies considered many factors, including the need to make transmission upgrades, replacement power needs, net book value ("NBV") of the asset, future fuel prices, future capacity factors, and timing of environmental compliance. The results of the retirement studies supported the Company's decision made at that time to maintain operations at these units.

Q. PLEASE EXPLAIN FURTHER HOW THE RETIREMENT STUDIES SUPPORTED MAINTAINING OPERATIONS AT ALLEN STATION AND CLIFFSIDE UNIT 5.

A. The Company is legally required to operate its units in an environmentally compliant manner. The Company undertook these studies in order to make a timely decision regarding completion of the environmental upgrades at these units that were required by state and federal laws and regulations in order to maintain the units' environmental compliance and be able to continue reliably serving customers. The retirement studies evaluated the potential capital investments to make the mandatory environmental upgrades at Allen Station and Cliffside Unit 5 to ensure these units were compliant with the law against the risks of early retirement. Those risks included not having sufficient time to build replacement generation or secure needed transmission enhancements, and as a result not having the ability to maintain reliable operations for the Company's customers. Given the knowledge the Company had at the time, the studies did not show a compelling economic case for early retirement versus making the required capital investments. The Company therefore made the prudent decision in both cases to invest in the mandatory environmental upgrades to maintain these units' environmental compliance and therefore maintain operations to continue to be able to reliably serve customers.

Q. DID WITNESS STRUNK COMPLETE AN INDEPENDENT ANALYSIS OF THE EARLY RETIREMENT OF THESE UNITS WITH THE INFORMATION KNOWN TO THE COMPANY AT THE TIME?

A. No. Witness Strunk made clear that he did not "independently assess[] the retrospective economics of a potential decision" to retire either Cliffside Unit 5 or Allen Station. Instead, he relied on capacity factor projections from the time of the studies and the additional factor of the risk of NBV non-recovery to question the prudency of the Company's decisions.

Q. ARE WITNESS STRUNK'S CLAIMS WITH REGARD TO THE COMPANY'S MOTIVATIONS FOR ITS DECISION REGARDING RETIREMENT OF ALLEN STATION VALID?

A. No. Witness Strunk questioned the Company's decision based on the 2017 Allen retirement study's identification of the risk of non-recovery of the NBV of the Allen units associated with early retirement. While he acknowledged the reasonableness of this consideration, he framed this factor as the primary consideration relied on for the decision not to early retire. This is not the case. Witness Strunk disregarded the other factors that the presentation he cites also describes. His testimony also ignored the fact that the NBV is not part of the economic analysis of early retirement but is rather an additional consideration separate and apart from that analysis. On its own, the Allen retirement study's economic analysis did not support early retirement.

Q. WHAT IS YOUR RESPONSE TO WITNESS STRUNK'S TESTIMONY REGARDING THE COMPANY'S LATER DECISION TO ACCELERATE DEPRECIATION OF ALLEN UNITS 4 AND 5 AND CLIFFSIDE UNIT 5?

A. Witness Strunk noted multiple times that subsequent to the 2016 and 2017 retirement studies, the Company determined it to be appropriate to "retire" Cliffside Unit 5 and Allen Units 4 and 5 early. In my view this change in course shows that the Company is making the best decisions it can at the time with the information available at that time. With the benefit of new and updated information about costs and risks, the Company did subsequent to the initial studies decide to propose accelerated depreciation of Allen Units 4 and 5 and Cliffside Unit 5. That proposal is before the Commission in this case, but it does not indicate that the earlier decisions were imprudent – the opposite is in fact the case.

Q. WHAT IS YOUR RESPONSE TO CLAIMS MADE BY WITNESS STRUNK AND SIERRA CLUB WITNESS WILSON THAT QUESTION THE PRUDENCE OF INVESTMENTS IN THE COMPANY'S COAL UNITS DUE TO THOSE UNITS BEING "UNECONOMIC"?

A. Witness Strunk focused on projected unit capacity factors and made a series of claims regarding the economics of coal fired generation. Witness Wilson spent a large portion of her testimony discussing what she terms the "negative net value" of the Company's coal units. Neither witness, however, recognized the full picture of how the Company dispatches its coal fleet to maximize value for customers. The Company's economic dispatch model supports active management of the fleet in order to provide reliable cost-effective generation for its customers. The model, which produces unit commitment and dispatch projections, utilizes variable costs rather than fixed costs, which are contractually required to be spent whether the units run or not. The variable costs utilized in the model, for example, include but are not limited to fuel, variable O&M, reagents, emission allowances, and startup fuel and wear and tear.

The economic dispatch model will economically optimize total system variable cost over a 7-day forecast period. Witness Wilson's study does not appear to account for the requirement of day-ahead planning reserves. On a day-ahead basis, the Company is required to plan on at least 1,770 MW of capacity above and beyond DE Carolinas' expected peak load. Capacity must be online (or available within 10 minutes). A coal unit will provide energy and capacity during the peak. The Company recognizes that the capacity factors of its coal fleet are declining. For example, Allen Station's operation strategy has shifted from a baseload to a cycling resource. However, the Company requires cycling resources, which operate at lower capacity factors, to provide reliable service to customers in periods of high demand. If a needed coal unit were not online then the Company would have to start additional CTs and/or purchase energy and capacity from the market, assuming capacity was available during such a time. Lastly, witness Wilson's analysis does not appear to value ancillary services, such as regulation, provided by coal units.

Q. WITNESS WILSON ALSO DISCUSSED HER "FORWARD-LOOKING ANALYSIS OF DEC COAL UNITS." IS THIS ANALYSIS A VALID EXERCISE IN A GENERAL BASE RATE CASE?

A. No. Witness Wilson's testimony in this regard concerned forward-looking IRP-related issues. The rate case docket is the proper proceeding to determine whether the Company's capital expenditures sought for recovery were reasonable and prudent. Conversely, the IRP docket is the proper proceeding in which to determine the appropriate generation mix to serve the Company's projected load under varying assumptions around carbon pricing.

Q. DID WITNESS WILSON MAKE ANY OTHER RECOMMENDATIONS WITH REGARD TO FUTURE COSTS RELATED TO THE COMPANY'S COAL FLEET?

A. Yes. She recommended that the Company's future capital expenditures "intended to prolong the lives of coal units" be limited and that "utilities" be required to come for approval of any expenditure that exceeds the cap before recovery.

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. No. Witness Wilson did not elaborate as to how such a cap would be determined. In addition, these investments are not made to "prolong" the life of particular units but rather to maximize their remaining useful life. For example, the DFO projects provide more fuel flexibility and therefore savings for customers.

More broadly, the Company is already doing what witness Wilson is suggesting, right here in this rate case. That is, the Company is requesting to recover the costs of capital investments made in its coal fleet during the test year through January 31, 2020. The Company cannot recover these costs from customers unless and until the Commission permits it to do so.

Finally, while the Company provided estimates of future capital investments to Sierra Club through discovery, DE Carolinas also explained in those discovery responses that future capital investments are not relevant to this proceeding.

Q. WOULD YOU LIKE TO ADDRESS ANY OTHER ASPECTS OF WITNESS WILSON'S TESTIMONY?

A. Yes. Witness Wilson discussed the requirement that facilities be used and useful in providing service to customers to be recoverable through rates. She suggested that a facility may not be "useful" if it was planned in a prudent manner but "operate[s] at costs significantly higher than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee."

Q. DO YOU HAVE AN OPINION ON WITNESS WILSON'S DISCUSSION OF THE TERM "USEFUL"?

A. Yes, to the extent that she intended this discussion to criticize the Company's capital investments as not being used and useful. As stated above, I am not a lawyer, however, in my experience I have not seen the term "useful" applied in this way. Additionally, witness Wilson did not identify any specific capital investment operated by the Company as not "useful."

Q. WHAT IS YOUR RESPONSE GENERALLY TO NC WARN WITNESS POWERS' CLAIM THAT THE COMPANY'S INVESTMENTS IN THE DFO PROJECTS AT BELEWS CREEK AND CLIFFSIDE WERE NOT REASONABLE OR PRUDENT?

A. I disagree with witness Powers. The Company's investments in the DFO conversion projects were reasonably and prudently incurred and should be recovered. The Company conducted multiple cost-benefit analyses of the DFO conversion projects. These analyses indicated that the Company and its customers would gain economic value from the DFO conversion projects in the form of optionality with fluctuating coal and natural gas commodity prices, which flexibility in turn will allow DE Carolinas to continue to lower fuel costs for its customers.

Q. HAS THE COMPANY EXPERIENCED OTHER BENEFITS FROM THE DFO CONVERSION PROJECTS?

A. Yes. The fuel flexibility associated with these projects has been enhanced at Cliffside by the restructuring of the coal delivery contract with the rail service company that supplies coal to Cliffside. The Company's customers are not only benefiting from the option to burn natural gas in place of coal when it is economically optimal to do so at Cliffside, but also from lower cost transportation rates resulting from the railroad's need to compete against natural gas burns, including the direct competition presented by the implementation of DFO at Cliffside.

In addition, while Cliffside Unit 6's thermal efficiency does decline with DFO, its auxiliary load has also decreased by approximately 10 MW due to the elimination or reduction of the need for coal processing systems, ash systems, and wastewater treatment systems depending on whether the unit is on full natural gas operations or is co-firing coal and natural gas.

Q. WHAT IS YOUR RESPONSE TO SUGGESTIONS THAT THE COMPANY COULD PROVIDE RELIABLE CUSTOMER SERVICE WITHOUT THE CONTINUED AVAILABILITY OF ITS COAL FLEET THROUGH PURCHASED POWER AND RENEWABLE RESOURCES?

A. Tech Customers witness Strunk suggested that, while he himself has not performed a "detailed 'IRP'-type analysis," the Company could replace energy and capacity associated with a retired unit with purchased power, surplus capacity, utility-scale renewables, and energy efficiency and demand response. NC WARN witness Powers claimed that existing regional merchant combined cycle and hydroelectric plants could supply Duke Energy with lower-cost power than he argues can be obtained from Belews Creek or Cliffside.

Neither witness, however, offers a credible and specific explanation of how the Company could have replaced the approximately 3,615 MW of reliable generation provided by Belews Creek and Cliffside, or the approximately 1,060 MW provided by Allen Units 4 and 5 and Cliffside Unit 5, with purchased power and renewable resources. And neither witness credibly challenges the

Company's reasonable and prudent decisions to maintain operations at Allen and Cliffside Unit 5 and to invest in the DFO projects at Belews Creek and Cliffside, as I have discussed in this testimony.

V. OTHER PUBLIC STAFF RECOMMENDATIONS

Q. ARE THERE ANY OTHER RECOMMENDATIONS ON WHICH YOU WISH TO COMMENT?

A. Yes. Public Staff witness Metz testified that in order to assist the Public Staff to evaluate the Company's decisions to make significant capital investments in its electric system, including consideration of alternative investments considered and not chosen, the Public Staff recommended that the Commission direct the Company to begin collaborating with the Public Staff within three months following conclusion of the rate case to clarify expectations for project evaluation and selection and document creation and retention. He stated that this will allow both the Company and Public Staff to be more efficient in requesting and reviewing project specific documentation going forward. In addition, witness Metz recommended that the Company complete an independent audit of M&S inventory for at least one nuclear station, one fossil station, and one hydro station by the time of its next general rate case filing, or within the next three years, whichever is sooner, and establish a long term schedule for a continuous independent audit cycle (e.g., a three to five year rotational cycle).

Q. WHAT IS YOUR RESPONSE TO WITNESS METZ'S PROPOSAL FOR THE COMPANY AND THE PUBLIC STAFF TO COLLABORATE ON PROJECT EVALUATION AND SELECTION AND DOCUMENT CREATION AND RETENTION?

A. The Company does not oppose this recommendation.

Q. WHAT IS YOUR RESPONSE TO WITNESS METZ'S RECOMMENDATION WITH RESPECT TO PERIODIC INDEPENDENT AUDITS OF M&S INVENTORY?

A. The Company does not oppose witness Metz's recommendation. However, DE Carolinas believes that the Company should utilize Duke Energy's own independent Audit Services Department to meet this recommendation. The Audit Services Department is required to maintain independence and objectivity in its work. It reports to the Audit Committee of the Board of Directors and to Duke Energy's senior ethics and compliance officer. The Department is authorized to have full, unrestricted access to all Duke Energy functions, records, property, and personnel, and to obtain the necessary assistance of personnel in audited units, as well as other specialized services from within or outside the Duke Energy enterprise. Company witness Capps will address this recommendation with respect to DE Carolinas' nuclear facilities.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Duke Energy Carolinas, LLC
Steve Immel Direct and Rebuttal Testimony Summary
Docket No. E-7, Sub 1214

My direct and rebuttal testimonies support the costs of capital investments and operations and maintenance expenses that the Company has incurred for its fossil/hydro/solar operations or "FHO" fleet since DEC's previous North Carolina rate case. As discussed in my testimonies, the Company reasonably and prudently incurred the costs for these investments, and they were necessary for the Company to continue providing safe, reliable, and cost-effective electric service for customers while continuing to maintain efficient operation of the assets with high quality performance.

The Company's FHO generation portfolio consists of approximately 14,992 megawatts of generation capacity. This portfolio includes a diverse mix of generation facilities to meet our customers' load requirements. These facilities operated efficiently and reliably during the test period. Since DEC's last rate case, a significant portion of critical investments were made to meet environmental regulations and were necessary to maintain the Company's history of safely providing efficient, reliable, and cost-effective generation. In addition, the dual fuel operations conversion projects at Cliffside Station and Belews Creek Unit 1 allow the Company to utilize the most cost-effective fuel at these stations for the benefit of customers.

In rebuttal, I explain how the arguments raised by parties in opposition to our coal plant investments misunderstand the realities of operating our system and fail to capture the complete picture of how the Company dispatches its coal fleet. These arguments also disregard the capacity value these units offer. No party presented prudent alternatives that DEC reasonably could have chosen to replace the approximately 6,700 MW of reliable capacity that our coal plants represent, instead of making these investments.

MS. KELLS: Thank you. Chair Mitchell, the witness is available for cross.

CHAIR MITCHELL: All right. Ms. Force or Ms. Townsend, you're up first.

MS. FORCE: Thank you. No questions from the Attorney General.

CHAIR MITCHELL: All right. Mr. Quinn, you're up next.

MR. QUINN: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. QUINN:

Q. Good afternoon, Mr. Immel. My name is Matthew Quinn. I'm an attorney on behalf of NC WARN. I am going to ask you just a few questions this afternoon. Specifically, I'd like to speak with you a few minutes about Duke Energy Carolinas' DFO projects for which it requests reimbursement in this rate case. And when I say DFO, I'm referring to dual fuel optimization.

Is that a fair acronym to use, sir?

A. Yes, sir, it is.

Q. Okay. Now, my understanding is that the DFO projects which are part of this rate case are Cliffside units 5 and 6 and Belews Creek unit 1; is that right?

A. That is correct.

Q. All right. And for these DFO projects, what is the amount of money for which DEC is requesting reimbursement in this rate case?

A. It's -- approximately $125 million was the cost to implement at those three units you referenced, Cliffside 5, 6, and Belews Creek 1; and then about another about $120 million associated with the capital pipelines.

Q. Okay. And these DFO projects, they will permit these units at Belews Creek and Cliffside to burn some combination of coal and natural gas; is that a fair understanding?

A. That is correct. A combination or, in fact, Cliffside 6 could burn just gas, 100 percent gas, as well as Belews Creek, we could get 50 percent capacity on just gas without any coal. And, of course, any combination; yes, sir.

Q. Now, prior to the implementation of these DFO projects or the DFO construction, these subject units at Belews Creek and Cliffside, they were coal-fired units; is that right?

A. Yes, sir. Polarized coal, correct.

Q. Okay. And they used steam boilers at these units; is that right?

A. That is correct; yes, sir.

Q. Okay. All right. So now we're using these same steam boilers to be fired by either coal or natural gas, correct?

A. That is correct; yes, sir.

Q. Okay. Now, would you agree with me, sir, that burning natural gas in steam boilers formerly fired by coal reduces the thermal efficiency of the steam boiler?

A. There is a very slight reduction in the heat rate, which is a measure of the unit efficiency. There is a small decrease in the efficiency. It's due to the amount of moisture that is in the gas, the fuel. However, when we are not burning coal, it removes a lot of the auxiliary electrical load from the pulverizers, from all the coal handling equipment that pretty much offsets that thermal inefficiency which you described.

Q. Okay. I appreciate that. And just to make sure I understand, it is, in fact, correct that these DFO projects reduce the thermal efficiency of the steam boilers at these units, right?

A. It reduces the thermal efficiency of the boiler component, but the overall efficiency of the generating unit is very minimally impacted since we are able to reduce the auxiliary flows by not polarizing coal.

Q. Mr. Immel, I want to ask you a question I don't think is a controversial question, but would you agree with me there is a trend in the public utility industry moving away from coal and toward other forms of electricity generation?

A. Yes, sir, I would agree with that.

Q. And that trend's been going on for several years now; is that fair?

A. Yes, sir.

Q. Okay. Is it fair to say it's been going on for five years?

A. It's probably fair to say that. Gradually been increasing; yes, sir.

Q. Do you recall, sir, when construction of the DFO project at Cliffside unit 5 began?

A. I do not know the exact month. It went into commercial operation in late '18, so it probably started construction in the spring of '18.

Q. Okay. All right. And --

A. Subject to check.

Q. And the spring of '18 is good enough for my purposes.

So would you, then, agree that, at least at the time that this DFO project was undertaken, construction was undertaken at Cliffside unit 5, this trend we discussed a moment ago, moving away from coal, had already begun; is that correct?

A. Yes. And as you describe a trend -- if I could maybe comment on that trend. What creates the trend is the continued lower price of natural gas, which, of course, is a benefit to our customers, and also the continued improvement in technology efficiencies of combustion turbines. So you have machines that continue to get more efficient on natural gas, and -- over the period of time you're talking about you also have a declining fuel price; yes, sir. That completes the trend.

Q. Okay. Mr. Immel, would you also agree with me that, at the time that the business decision was made to implement the DFO project at Cliffside unit 5, the projected retirement date for that unit was 2032?

A. Yes, sir. The time that we pursued this would have been in the late 2016 time frame; yes, sir.

Q. Okay. Now, obviously, Duke Energy Carolinas is requesting that the retirement date of that unit be shortened to 2026 in this docket, correct?

A. That is correct.

Q. So ratepayers are going to have six years fewer to reap the benefits from Cliffside unit 5 DFO than was expected when the project began; is that fair to say?

A. That is fair to say. If I could describe some of those benefits, though, that you mentioned. You know, earlier you asked me the dollar figure of dual fuel. At Cliffside, the investment in dual fuel -- and I've got a summary here to my right that I'm looking at -- it was approximately $54 million in total. $18 million of the 54, which is a considerable amount of money, that is the amount that was spent on Cliffside 5. And so since the addition of dual fuel, we've had the ability to start units now on gas versus fuel or diesel fuel that was done in the past. So some immediate savings to customers have been realized since we went -- when we went commercial with these units.

Q. All right. No more questions, Mr. Immel. Thank you.

A. Thank you, Mr. Quinn.

CHAIR MITCHELL: All right. Ms. Lee?

MS. LEE: Thank you, Chair.

CROSS EXAMINATION BY MS. LEE:

Q. Good afternoon, Mr. Immel. I believe we may have met on occasion before, but again, my name is Bridget Lee, and I represent the Sierra Club in these proceedings. I'd like to ask you a few questions today about Duke Energy Carolinas' coal fleet, if that would be all right.

A. Certainly. Good afternoon.

Q. And the -- that fleet includes 13 coal-fired units at four separate plants; is that right?

A. That is correct, yes.

Q. Okay. And of those 13 units, all but one began operating over 45 years ago; is that right?

A. That -- that certainly sounds in the neighborhood, yes.

Q. Sure. Subject to check?

A. Certainly, yes.

Q. Okay. And the Allen plant, where I believe you have some additional history working as a manager, that's the oldest plant in the fleet and it first came online 63 years ago in 1957; is that right?

A. That's correct. Unit 1 and 2, I think, went commercial in '57.

Q. Okay. Mr. Immel, when does the Company expect to retire the Allen station units?

A. Well, the -- in this rate case, this -- what we have filed for accelerated depreciation is units 1, 2, and 3 in '24, which is no change; and units 4 and 5 we accelerated from '28 to '24.

Q. Okay. And in the integrated resource plan the Company filed earlier this week, it was indicated that the most economic retirement year for Allen units 2, 3, and 4 was 2022; am I getting that right?

A. That is correct. So that was filed just this week, as a matter of fact, September. Yes, that is correct.

Q. Okay. Can you explain to me the -- that difference of two years? So with respect to the analysis that was done in the IRP versus, I guess, the depreciation study that gave the Company the 2024 date, what changed or what additional factors were taken into consideration?

A. Well, the -- I guess to begin with we're -- we're maybe a year apart from the time that the filing for this rate adjustment versus the IRP that was just filed. The inputs to these reviews are constantly changing. The -- there's many inputs into it. So fuel forecast, price of gas, price of coal, continues to change. Technology, whether it's renewables, whether it's gas turbine technologies, those prices continue to change. Our load demand forecast also continues to change. So if the question is why did it change, it's a lot of those factors.

Q. Understood. Thank you. Okay. Turning to your rebuttal testimony, I'm looking at page 9, line 18.

And here you state that the Company studied the potential early retirement of Cliffside unit 5 and Allen station in 2016 and 2017 respectively; did I get that right?

(Pause.)

THE WITNESS: Bridget, can you hear me?

Yes.

Q. Yes, I can now.

A. Okay.

Q. Okay. Great. So let's turn to Cliffside unit 5 for a moment, if we may.

What was your involvement in preparing the Company's 2016 study of the potential early retirement of that unit?

A. At that time, I really had no involvement of putting the study together.

Q. Okay. Are you familiar with the methodology that was used to conduct that study?

A. Somewhat familiar.

Q. Okay. Do you know if a capacity optimization model was used to do that study?

A. I'm not familiar with the term "capacity optimization," no.

Q. Okay. Let me take a step back.

To your understanding, if you could just describe the methodology in brief, that would be great.

A. In that particular analysis in the presentation that, of course, I had the opportunity to review, even though I was not part of the preparation of it, it was done at a time when we were exploring coal-to-gas opportunities. We were exploring -- not just in the Carolinas, across the entire coal fleet that we operate, we were exploring what are those opportunities to economically bring gas in and explore potential retirement of some of the coal facilities. So that was the time frame that this took place.

Cliffside was a station that it seemed very feasible, due to the location of a gas transmission line. So it was economically feasible to bring in gas to that site to the benefit of the customer. And so, as they evaluated the retirement -- and at that point in time, and again, this was in late 2016 when they did the analysis, the analysis would include -- to your question, the analysis would include what is the cost of replacement capacity at that time that we reviewed. It would also look at what is the investment -- the capital investments over the short term that you might avoid if you were to retire early. Those are probably some of the larger inputs. And then we also make some assumptions on what might be carbon legislation in the future. That would be -- there's many more inputs than that, but that would be some of the inputs.

Q. Sure. Thank you. That's very helpful.

Would it be fair to understand with that study, the replacement resource considered was -- the Company was only considering a gas replacement?

A. In that analysis, it was studied to be replaced with gas turbines; that is correct. But I would say, prior to making that assumption, we go back and look at IRP -- previous IRP filings, what is the most economical replacement, dispatchable resource. At this time -- at that time, you know, solar and the current battery technology, it was difficult to have those resources referred to as dispatchable. You can't cut them off and you can't turn them on in the middle of the night, et cetera.

So that is all weighed into the decision that we pick the most economical replacement for the customer, which at that time, again, was combustion turbines, correct.

Q. Thank you. And I think you mentioned as part of that study, the folks conducting it would have considered potential cost savings, I guess, forward-looking capital expenditures at Cliffside unit 5 and which of those might be avoided; is that fair?

A. That is correct; yes, ma'am.

Q. Okay. And the Company has incurred a number of capital expenditures at Cliffside unit 5 between that 2016 analysis and the start of these proceedings; is that right?

A. That is correct.

Q. Okay. And those would include the conversion to dry handling of bottom ash, a scrubber wastewater treatment system?

A. Yes. Along with, of course, all the processed water, and the stormwater reroutes, and retention basins, et cetera; that's correct.

Q. Okay. And did that 2016 analysis consider specifically each of those three buckets of costs and consider specifically the savings that could be enjoyed if those were avoided?

A. It is my understanding they did. In some cases -- and I'm not sure how they separated it, but in some of those cases with the larger redirection of stormwater and processed water, et cetera, they were also required for unit 6. So I'm not sure how they segregated those costs, but yes, they were considered.

Q. Understood. And would those pieces of work, were those required under CAMA?

A. They would be required under CAMA and federal CCR regulation, yes.

Q. And do you know, is the CAMA deadline for ending discharges of bottom ash transport water, is that a sooner deadline than the deadlines in the federal rule?

A. You are -- that question is certainly better answered by witness Bednarcik, but my understanding is, at Cliffside, our compliance date was in 2019.

Q. Okay. And this is a question I asked Mr. De May this morning, and he thought you would know the answer.

Did the Company seek -- actually, I should take that back. I asked him this question with respect to the Allen plant, but I'll ask it to you with respect to Cliffside unit 5 as well.

Did the Company seek any variance of the CAMA deadlines for that plant?

A. It's -- it's my understanding at Allen station, because it's one of the exhibits, of course, we did -- we did explore a variance. I'm not too sure to what extent it was explored, but the short answer was it would not be supported. And Jessica Bednarcik -- and I hate to push your question off to another witness -- but she is very familiar with the variance process that DEQ uses in terms of this. So she would have a much better answer.

Q. Okay. No problem. And I think I'll have some questions for you about Allen in a moment, but just to stick with Cliffside 5 for a second here.

Do you know whether or not the Company sought variance from the CAMA deadlines for that unit?

A. I do not know.

Q. Okay. We can ask Ms. Bednarcik.

Aside from those environmental compliance costs that we mentioned, would there be other capital expenditures expected over the remaining lifespan of Cliffside unit 5?

A. Certainly. There was -- there will certainly be what we refer to as major inspections, major generator inspections over the life of the unit. Those would be -- those possibly would not take place if it was retired early. We also looked at, you know, potential new water regulations that might require capital investments. So those would be part of that potential savings if we had retired early.

Q. Thank you. Mr. Immel, are you familiar with this Commission's August 27, 2019, order in the Company's IRP docket?

A. I am not.

Q. Okay. Let's talk about Allen quickly.

Your testimony also pointed to an early retirement analysis that was conducted for the Allen units in 2017; is that right?

A. Correct, yes, ma'am.

Q. And did you have any involvement in preparing that study?

A. I did not, no.

Q. Okay. So is it fair to understand that your knowledge of it is limited to the 6-page slide deck and appendix that the Company has made available during discovery in this case?

A. I would say that's fair to say, yes.

Q. Okay. And if you could describe for me a little bit about the methodology of that study, if it was along similar line what you described for Cliffside, or was it different somehow?

A. The -- similar -- very similar. One of the -- one of the differences would be we were not exploring bringing in a gas pipeline. Based on location of the closest gas transmission line, Allen was not economically feasible for the customers to bring in an alternate fuel source, so that was different than Cliffside. We were certainly looking at, prior to making a significant investment in the environmental systems, to comply, which would be as you mentioned before, bottom ash conversions, rerouting of processed water, stormwater retirement, line retention basins, and also some improvements on our wastewater treatment facilities. A significant amount of money, so we conducted the analysis just to see what's the potential if we could retire earlier to avoid some of that capital expenditure.

Q. Okay. And in conducting that analysis, was -- was the Company looking at a number of different alternatives, or was it limited to replacement generation that would be gas-fired as we saw in the Cliffside study?

A. It would be similar to my response on the Cliffside study. And Allen would have also an added complexity. Based on its location, in terms of its location on our grid, on our transmission system, it's critical to have 100 kV generation at that point in the transmission system due to some voltage support concerns. So it had the added complexity there versus that at Cliffside.

Q. Okay. Thank you. Mr. Immel, in the 2020 IRP that was filed this week, Allen units 2, 3, and 4 were designated with an earlier assumed retirement date. And in that document, the Company indicated that those units would be able to retire by 2022 without any additional transmission or generation; is that correct?

A. That is correct. So units 2, 3, and 4 are connected to the 230 kV transmission system.

Q. I see.

A. Actually, 3 and 4 are connected to the 230 kV system; units 1, 2, and 5 are connected to the 100 kV. In support of our transmission switch yard project and replacement of these auto back transformers, transmission is requiring two 100 kV connected units, and the Company is picking out 1 and 5 in particular; yes, ma'am.

Q. Understood. Okay. So that -- that would account for the transmission needs you mentioned being highlighted in the early retirement study and why those wouldn't be a problem with respect to the units retiring by 2022, if I'm understanding you correctly?

A. Correct. Of course, at the time of the analysis, which is approximately four years ago, there was a need for capacity replacement. Fast forward four years, looking at all the variables I mentioned earlier, per this recent filing, the long-range planning would suggest capacity replacement is not required now, correct.

Q. Thank you. And is that diminished need for capacity, is that a function of additional generation resources that have come online, or a drop in demand, or something else?

A. I would -- I would say it's everything you just described. We certainly have added new transmission or new generation sources, including renewables. And, of course, demand is certainly a function of that as well, yes.

Q. Thank you. I'm looking at -- and I don't think you actually need to turn here, but I'm looking at page 6, line 11 of your direct testimony where you've identified $689 million of capital investments for the coal fleet.

Would you say approximately $100 million or so of that number is -- was spent on Allen plant retrofits?

A. I would actually say it's more than that.

Q. Okay.

A. 600- -- yeah, the roughly $690 million that is referenced in my direct testimony, that was, in fact, systems that were put into service at all four of the coal facilities as you described earlier in response to the new environmental regulations, CCR, CAMA, as well as the steam effluent limitation guidelines. And so of that 689, approximately $150 million was spent at Allen station.

Q. Okay. Great. Thank you. And of that $150 million, would some of those costs be more routine maintenance at the boilers and things of that sort, as opposed to the regulatory compliance costs?

A. No. That $150 million is all around the environmental cost. And I might add, roughly $70 million of that 150, it would have been needed to be spent irregardless if we retired the unit in '17 or not, because we had to -- we had to cease flows into the current ash ponds, which would require us to reroute processed water, stormwater flows, line retention basins. So of that $150 million, $70 million was going to be spent irregardless of the timing.

So as you ask about what about other maintenance costs, in this current proceeding in our request, approximately $15 million was spent at Allen in terms of what I refer to as maintenance capital.

Q. Okay. Thank you, Mr. Immel, for that.

The $70 million for ceasing flows, that was required to be spent under CAMA?

A. Well, I think -- and I'm going to answer, then I think more details will go to Jessica.

Q. Sure.

A. But CAMA and CCR carry a lot of the same regulatory requirement. I think CAMA probably drove some of the schedule, but very similar regulation.

Q. Okay. And again, I think you've mentioned that Ms. Bednarcik probably has more detail on this, but is it your understanding that the Company did seek a variance from DEQ with respect to the Allen CAMA deadlines?

A. I'm not -- what was shared with me is DEQ would not be supportive of a variance. Whether or not we requested the variance, I think Jessica can help with that. She actually can help with the whole process on how you go about requesting the variance.

Q. Okay.

A. So we had determined they were not supportive of a variance.

Q. Okay. Thank you. Yes, we'll put aside the details of what a request like that might have looked like, but from your perspective, if a variance had been requested and had been approved, would early retirement of any of the Allen units then have been viable?

MS. KELLS: I object to the question as calling for speculation.

CHAIR MITCHELL: All right. Ms. Lee, what's your response, please?

MS. LEE: I'm interested in Mr. Immel's, you know, understanding of what decision-making goes into an early retirement study of this sort. If this is one of the main factors, I think it's important to understand, if it had been approved, what the study could have looked like.

CHAIR MITCHELL: All right. I'll let

the question -- I'll overrule the objection and let you proceed with your question, Ms. Lee.

THE WITNESS: Could you ask it one more time, please?

Q. I sure could. If a variance was approved, would the early retirement of any of the Allen units have been viable?

A. And this is speculation, but I've been asked to speculate. I'm going to say it would not have been viable for many of the reasons we've already talked about. We had transmission constraints, as we still have transmission constraints, as you mentioned in the current IRP filing. So we could not retire due to transmission constraints. We could not remove all that generation from the 100 kV system.

And then also the variance, it really would only address a portion of the cost around bottom ash conversion. The variance would have nothing to do with removal of the processed water, the stormwater flows, getting out of the retired ash basin. Those costs were going to take place. So the variance would really address -- maybe some optionality in our bottom ash system is really all that it would address.

So if I were to speculate, I do not think we would retire early. I think -- in looking backwards, I think we made a very sound decision, probably the same decision we would make today.

Q. Okay. Thank you. And in reaching the decision that was made, did the Company consider whether the plant would be fully depreciated by the proposed retirement date?

A. We certainly looked at what would be the net book value that would be, you know, left at the time of retirement. We certainly look at that, but that is -- that is not part of the economic analysis that was performed. You know, as we mentioned before, all the inputs in terms of what does it cost to replace the capacity, what's the future cost, what's the current cost to meet regulations; all that drives the decision, do you retire or do you invest. When it comes to net book value, that's just another aside -- it's another factor for the executives that make that decision.

Q. Okay. Understood. And putting aside for the moment the feasibility of retiring any of the Allen units earlier than 2024, back in 2017 when the Company conducted the evaluation of whether or not to invest in various retrofits that we've discussed, did it consider it prudent to make upgrades to the plant that might only be utilized for a handful of years?

A. Well, when you say "prudent for a handful of years," what we were faced with was a considerable investment to remain compliant by a 2019 date, not sure of the month. But we were faced with retire it. And if we don't retire it, there was -- certainly it was prudent and reasonable. We had to -- we had to -- we're going to operate an environmentally compliant fleet, so we had to make those investments. I don't know if that answered your question.

Q. I think that's good enough for now.

If you could, Mr. Immel, please turn to your rebuttal testimony, page 13, line 4? Are you there?

A. Yes, ma'am.

Q. Oh, great. So do you see where you're talking about the Company's economic dispatch model and state, quote, utilizes variable costs rather than fixed costs, which are contractually required to be spent whether the units run or not, end quote?

A. Yes.

Q. So would you agree that there's -- certain fixed costs would be avoided if a unit were to retire?

A. Certainly.

Q. Okay. So whether they were considered by the dispatch model or not, those fixed costs would affect the overall profitability of a unit, or the net value of the unit?

A. Well, if I could go back and look at the context of this response and this rebuttal, which is to Sierra Club witness Wilson's testimony, she's -- she's determining, I think in her words she calls them economic value of the units. And she uses cost, and she uses the energy that the -- that the unit produces, the energy, the amount of megawatt hours. And what I'm describing here is we operate -- Duke Energy operates a fleet, a very efficient fleet of nuclear, hydro, pump storage, solar, coal, gas. It's an integrated system, and there's a capacity value that witness Wilson did not consider. She put -- she put all her cost on how much energy is produced.

You know, it would be -- an interesting contrast would be take one of our combustion turbines, which is typically just for cycling, just for peaking, just to be able to have spending reserve if we lose a bigger unit. There might be some years those units don't run at all. And to put all that fixed cost on those units just doesn't make sense. There is a value in capacity.

And I think as she analyzed the Allen station, which is 1,100-plus megawatts, all she was considering was how much energy it produced. And in my rebuttal I'm trying to describe, we operate it as a system, we dispatch it as a system. Yes, there's a fixed cost, but there's a value in that capacity of that plant. Even if it doesn't run, there's a value.

Q. Okay. And -- but didn't -- didn't witness Wilson's analysis show that the Company's coal units were, in fact, more profitable during those peak winter hours where they were being called on for their capacity?

A. Yes. And again, she -- I think she did the same thing, is she picked out those weeks that they might have run and put an energy price on it and calculated the value. But, in retrospect, how do you forecast when you need that capacity? That's why we have capacity reserves. We have long-range planning reserves, and we have daily operating reserves.

So you certainly have to match your generation supply with what the customers' demand is. And to do that -- and you have to do it in real time. And to do that, you have to have a certain amount of capacity ready reserve to supply what the customer needs. So there's a value of those units when they're not running.

Q. Okay. Thank you. I don't have any other questions for you, Mr. Immel. Thank you very much for your time.

A. Thank you.

CHAIR MITCHELL: All right. Thank you, Ms. Lee.

Mr. Trathen, you are up next.

MR. SCHAUER: Chair Mitchell, this is Craig Schauer on behalf of Tech Customers. In light of the questions that have been asked, we do not have any questions at this time. We'd like to reserve our ability to ask questions on the Commission's questions. Thank you.

CHAIR MITCHELL: All right. Thank you, Mr. Schauer.

Any additional cross examination for the witness?

(No response.)

CHAIR MITCHELL: All right. Hearing none, any redirect for the witness?

MS. KELLS: Yes, Chair Mitchell, just a few.

REDIRECT EXAMINATION BY MS. KELLS:

Q. Mr. Immel, Mr. Quinn on behalf of NC WARN asked you some questions about the DFO or dual fuel optionality and conversion projects; do you recall that conversation?

A. I do.

Q. And you discussed with him some aspects of efficiency in the units that are impacted by those projects; do you recall those questions?

A. I do, yes, ma'am.

Q. Could you explain a little bit more what the Company's, you know, reason and purpose was in doing these projects, what are their benefits?

A. I would be happy to. We're pretty excited to be able to provide this to the customer. So by bringing in natural gas to these actually very efficient units, in particular Cliffside 6 and Belews Creek 1, extremely efficient units, we get -- the customer gets many benefits. One is we have fuel diversity and fuel flexibility, and we dispatch economically. So if gas prices happen to rise in the winter, then we can burn coal to the benefit of the customer, and vice versa. So we're able to fuel switch based on the least cost of the fuel.

And then there's a lot of ancillary benefits to this. A coal unit is very slow, what we refer to as ramping with load. So a Belews Creek unit which is 1,200 megawatts, it can ramp at a rate of about 8 megawatts per minute. So as people wake up in the morning and begin their day and our load ramps up, we've got to follow that load. And, of course, the gas turbines follow quickly, the coal plants follow more slowly. Takes a while to ramp.

Providing gas at Belews Creek, as an example, we've more than tripled the ability to ramp with load. With gas, we can ramp at 25 megawatts per minute in response to not only load but also our renewable portfolio now. So solar is a good example, it certainly has its place in our fleet, and we're glad to have it, but when cloud cover comes in or a thunderstorm pops up, and if you've got a couple hundred megawatts of solar on and all of a sudden that drops out -- and it drops out very quickly with cloud cover -- then you've got to fill in the gap, and you've got to fill it in it quickly. So being able to ramp these units quicker is important to enable the renewable generation.

And then I'll mention a couple more is, our minimum loads on these large coal plants, you take them down to a certain load and, you've got to keep a certain amount of coal in the unit to keep them online. And it's much more economical to keep a coal unit online than to cycle it complete offline, because then it takes a lot of heat to get it started back up.

And so to give you an example, a Belews Creek unit, on call their minimum load is about 350 megawatts. Firing on gas, we can go down as low as 300 and little bit lower than that even megawatts on gas. So we can keep the unit online during those lower periods of time and be able to ramp it up quicker.

So many advantages, besides just -- and then, of course, I think I mentioned -- maybe I didn't mention start-up. It takes a lot of fuel oil to start these coal units. I'll give you a little thumbnail. At Belews Creek, those are 1,200 megawatt boilers, very big spaces to heat up. If you're doing a cold start where you actually have to fire an auxiliary boiler to make steam and begin heating the coal boiler up, it takes about 140,000 gallons of diesel fuel to do that. And by replacing that with natural gas, we can save a considerable amount of money for customers just starting these units up. So a lot of advantages by bringing in the gas to these units.

Q. Thank you. And I think you answered this, but I just wanted to be sure. When the Company was looking at the dual fuel projects, did I hear you correctly that most of the investment with these projects at the Cliffside location was for unit 6; is that correct?

A. That is correct, yes.

Q. And then -- and unit 6 can actually burn 100 percent on natural gas; is that correct?

A. Correct. So Cliffside 6 can go from zero to 100 percent on gas, or any combination of coal and gas. Cliffside 5, the smaller unit, roughly 500-megawatt unit, it's designed for 10 percent for start-up. Again, to save -- let's save the customer money when we start these up. We can certainly start on gas. That's what we've been doing now since we put the systems in. And it can burn up to 10 percent capacity -- that's capacity on gas -- if Cliffside 6 is running at 100 percent. If Cliffside 6 happens to be off in a maintenance outage or for whatever reason, we have the ability to bring Cliffside 5 up to 40 percent capacity on gas, again, to the benefit -- the economic benefit to the customer.

Q. And as we discussed -- you discussed with Ms. Lee and maybe Mr. Quinn, we all know the Company is currently asking to accelerate the depreciation of Cliffside unit 5 to 2026; is that correct?

A. That is correct.

Q. Okay. And so assuming that, you know, unit 5 is retired in the next few years, unit 6 will remain and can still burn -- run on 100 percent natural gas due to this project, correct?

A. That is correct, yes.

Q. And, Mr. Immel, are there other -- and forgive me if you mentioned this and I missed it. Is there a benefit related to reduction carbon emissions from installing these projects at these units?

A. Certainly is. I think the rule of thumb is the same megawatts from these units, in terms of a CO2 footprint, it's a 50 percent reduction replacing coal with gas. So there's certainly an opportunity to achieve our company's and now the state's clean energy plans, yes.

Q. And that had to do not only just for burning gas instead of coal, but in terms of start-up as well?

A. Absolutely. Compared to diesel fuel, that's correct.

Q. And can you explain that just a little bit more, with the fuel oil start-up for coal?

A. Right. Again, you're again reducing the amount of CO_2 reduction using clean natural gas versus a fuel product; that's correct.

Q. And, Mr. Immel, the Company -- you're aware, aren't you, and I think you referenced this in your testimony, the Company conducted cost-benefit analyses in order to see whether it was a good idea to do these DFO projects, didn't it?

A. That is correct.

Q. And evaluated the costs and benefits of the projects under, you know, multiple gas and coal spreads to see if they were a good idea; is that right?

A. That is correct, yes.

Q. And the results of those studies were the conclusion that these projects were in the best interest of customers, correct?

A. That is correct. And, you know, we are pursuing dual fuel at Belews Creek too currently, and at the Marshall station; that is correct.

Q. Thank you. Ms. Lee asked you some questions about the retirement studies that were done in the 2016/'17 time frame for Allen and Cliffside unit 5; do you recall that?

A. Yes.

Q. Can you explain to us just a little more by a little bit more background about what the purpose of those -- what exactly you were comparing in your studies? For instance, with Allen, was it the cost to install required environmental investments versus the cost that would be associated with retiring; is that accurate?

A. Yeah. So -- and I attempted to explain that on Cliffside. So as we look at the retirement analysis, we're looking at the investment that it would take to remain compliant with the current and future environmental regulations that we knew were coming at us. CCR, CAMA, EOG, all those new regulations. So we looked at that cost and continued the operations, or do you retire it early, and what has to happen to retire early? Of course, with Allen station, at the time we did the analysis, it was capacity replacement and it was transmission constraints. And as we weigh those analysis, it was the prudent decision for the customers were to make the environmental investment.

Q. And sticking with Allen for a moment, you mentioned the -- that there were certain environmental projects that had to be done no matter what was done with the unit, such as line retention basins and such; is that right?

A. That is correct.

Q. And then there were some other environmental investments that the Allen study determined that you didn't have time not to do. Basically things like the dry bottom ash conversions had to be done, I think you said, by 2019, and there wasn't time to get replacement generation placed by that date; is that right?

A. That is correct, if we were looking for retirement; that's correct.

Q. In your opinion, was the Company's decision that it made in 2016 to continue to maintain Allen, has that paid off for customers?

A. It certainly has. You know, the -- you know, I think it was referenced in Mr. De May's testimony earlier today. The cold snap in January 2018, we actually had all five units, all 1,150 megawatts on at Allen. For that week to 10 days they ran at a capacity factor of over 80 percent serving, you know, the customers. It's interesting, you know, the weather patterns certainly are changing. Just last October, October '19, which you would expect fall weather, if you recall we had a pretty significant heat snap, and we had all five units on at Allen again serving load.

And so -- as a matter of fact, this July I looked back. At one point we had all five units on, but we kept a couple of those units, I think 4 and 5 on for probably over a week, serving -- again, serving those peak demand times, yes.

Q. Thank you. And just, I guess, to back up a half step to the actual result of the study, the Allen study, you know, is -- your testimony describes that study didn't show a compelling case for early retirement, and so would you agree with that?

A. I would, yes.

Q. Okay. And what we mean when we say "not compelling" is that, you know, it didn't come out very strongly one way or the other, and then -- in terms of the economics, and then when you add in the timing factor that we've discussed, it wouldn't have been a prudent decision to retire early. Would you agree with that?

A. I would agree with that; that's correct.

Q. Just a couple more. You also discussed with Ms. Lee sort of the fixed costs and variable costs of the coal units; do you recall that conversation?

A. I do.

Q. And you were talking about capacity value.

And can you help us out and just say -- explain a little bit more, you know, what do we mean when we say a unit has capacity value?

A. So, again, I guess to look at the bigger picture, to manage the transmission system, you have to match the generation that you're producing in real time with the electricity the customers are using. If you don't match it, then you have -- then you have issues with frequencies, and voltage, et cetera. So you have to match it. So in terms of capacity, on a daily basis, we look at the weather and we forecast how much generation -- a lot of this is historical, but we look at, you know, how much generation typically do we need based on the weather patterns, the time of the year, the day of the week.

And then, as we plan that, you also plan -- if I get into too much detail here, but you also plan what we call a daily planning reserve. You also have to plan for the largest generating unit you have online if you were to lose that unit. You know, if you were to lose a unit, you've got to respond immediately. So that's part of our daily planning reserve.

For DEC, that is our Bear Creek pump storage facility, which is roughly 1,350 megawatts thereabouts. You have to plan for the loss of a generating unit. You also plan for you can't accurately predict the weather. So you add another 300 megawatts is what we use. You have to add that on, in terms of daily planning reserves. And then there's another number we put on there for regulation. You've got to be able -- you don't know how quick the renewables might drop out based on weather patterns, et cetera, so you've also got to plan to be able to put generation online or bring it offline quicker.

So you add all that up together. For DEC, we have an operating -- a daily operating reserve requirement of 17 -- a little over 1,700 megawatts. So it's important to recognize that's at capacity. And Allen station plays into that as we plan our daily. So again, there's a value in capacity of all these units. Allen station's -- certainly, their capacity factors have declined over a period of time for all the reasons we talked about earlier. We have lower gas prices, we have much more efficient technologies that are burning that gas. So you would expect -- we dispatch our fleet economically. You would expect the old coal units to start running less because we have more efficient, less costly units in front of them.

But it's critically important we have the capacity there. We put those units online to meet the demand of some of the examples I just gave.

Q. Thank you. And you -- Ms. Lee also discussed with you about Ms. Wilson's analysis, and we don't need to -- I don't have too much on that, but she did ask you a question about the -- Ms. Wilson's analysis showing that these units were more profitable during peak hours.

In order to be able to run during peak hours, as you just said, the Company also has to maintain the units in order so they can be available to run during those times; wouldn't you agree?

A. That is correct, yes.

Q. And in your opinion, is the measurement of profitability that the Sierra Club has put forth a valid one, in terms of valuing the Company's generation units?

A. No. Again, I think they -- I certainly appreciate what witness Wilson pulled together, but they have not considered anything in terms of value of capacity. So --

Q. Okay. Sorry, go ahead. Okay. And then you had a few -- a couple of questions about the 2020 IRP, and what's in that, in terms of readjusted planned retirement dates for Allen. I recognize you haven't spent much time with the 2020 IRP. It was just filed two days ago.

But -- and you know that, in this case, do you not, the Company is proposing to accelerate depreciation of certain units, Allen 4 and 5 and Cliffside 5; is that correct?

A. That is correct.

Q. And in doing that, you would agree with witness De May that the Company's recognizing these assets are likely going to retire it earlier than originally thought; is that right?

A. That's correct, yes.

Q. And is that due to a number of factors like the state's goals and Duke's own goals for carbon emissions, and gas prices, and those items?

A. Absolutely. Again, all those factors you mentioned. You know, continued lower gas prices, improved renewable technologies, and the cost of those technologies. Battery technology continues to improve. For all those reasons, we -- I do find it interesting.

So we conducted a retirement analysis on Allen almost four years ago now. It has been four years ago. And then you fast-forward to this -- to when we filed this rate case last year, and we want to accelerate those units.

And now you fast-forward from there to the IRP we just filed, and we're continuing to look for opportunities to retire coal, and in the most organized fashion and economic benefit to the customer. And also meeting the state's and our Company's greenhouse gas emission goals. So yes, I think we're all headed in the right direction there.

Q. And you tied those all together very nicely.

Do you think, in doing that constant re-evaluation and adjustment as needed, the Company allows itself to be more agile and flexible as it moves forward and the industry changes?

A. Absolutely, yes. And I would also add, I think we should be proud of this. Ms. Lee had mentioned the age of the Allen units. So the first two units came on in 1957. That's 63 years ago. And we're going to land a retirement within a couple of years of that. I would say that's pretty impressive.

Q. And, Mr. Immel, just based on your

understanding of the changes the Company's making in its plans for Allen and some other units, in your opinion, does that show that the Company is now putting into a plan the financial side of the equation that it's presenting in this case for accelerating those depreciable lives?

A. Can you ask that again?

Q. Absolutely. We were talking -- you were talking about how the Company has -- you know, re-evaluates its fleet through time, four years ago though -- you know, decided that keeping them maintained was prudent, and in this rate case as proposed to accelerate the depreciable lives, that that was the right thing to do. And then as we all know but hadn't delved into much yet, you know, you're readjusting your planned retirement for certain units in the 2020 IRP; do you recall those facts?

A. Yes.

Q. And do you think that in the -- by the 2020 IRP showing these advanced retirement dates, that lends support to the Company's request for accelerated depreciation in this rate case?

A. Absolutely. I think that's what I was trying to get at in my previous response. That's correct, yes.

Q. And you did so. I was restating it. Just a couple more.

You -- did the Company have any other prudent option, other than to make these investments in these plants?

A. In terms of the environmental investments, no. I think we made the very reasonable and prudent decisions, absolutely.

Q. And the Company evaluates all of its investments to make sure that they're reasonable and prudent; does it not?

A. Yes, it does.

Q. And did any party present any alternative that the Company had that it could have done otherwise?

A. Not that I saw, no.

MS. KELLS: That's all I have, Chair Mitchell. Thank you.

CHAIR MITCHELL: All right. Thank you, Ms. Kells. At this point we're going to take a short break for our court reporter. So we will go off the record. We'll come back on at 3:40.

(At this time, a recess was taken from 3:30 p.m. to 3:40 p.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please. We will take questions from Commissioners, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I have no questions. Thank you.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yes, thank you.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Immel, good afternoon.

A. Good afternoon.

Q. Just a couple of quick things. I'll try to be quick with them.

Does the Company have underway any project or projects to try to provide some substitution for Allen 1 and 5 to provide the necessary voltage support to the 100-kilowatt portion of the transmission system?

A. Yes, sir. That project that I referred to, in terms of the switch yard expansion at Allen, it is under design now; yes, sir.

Q. It's under design? What's the schedule for completion?

A. It would be completed end of '23 is the current plan. And that would include the replacement of two large 230 100 kV auto banks; that's correct.

Q. Well, even though -- and there's been some discussion of this -- you're talking about something that we haven't even taken official recognition of yet, but it's been talked about, and that's the 2020 IRP.

Even though there may be a date earlier than 2023 that's discussed in the IRP, is it correct, then, that the 100-kilovolt system is still going to be dependent upon Allen 1 and 5 through the end of 2023?

A. That is correct. That is correct. And it's required during the construction period. There will be certain configurations in that switch yard that they really need to have reliable connected generation; yes, sir.

Q. So during the construction period, there aren't any alternatives or substitutes that you could run in on a temporary basis if you were to shut down 1 and 5 earlier?

A. No, sir, not that I'm aware of; no, sir.

Q. My last question, because this was referred to you.

You know Mr. Issa Zarzar?

A. I do know him; yes, sir.

Q. Where is he employed? What's his title and his scope of responsibility currently?

A. Well, he is in the CCP organization, which is where witness Bednarcik is, and she could give you much more information. As I understand his current role is he has a group of project managers for a certain region in the Carolinas that they manage these environmental projects that we talked about.

Q. Thank you, sir. That's all have. Have a good afternoon.

A. Thank you, sir. You do the same.

CHAIR MITCHELL: Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

CHAIR MITCHELL: All right. Commissioner Hughes?

COMMISSIONER HUGHES: No questions at this time.

CHAIR MITCHELL: Okay. And Commissioner McKissick?

COMMISSIONER McKISSICK: No questions at

this time.

CHAIR MITCHELL: All right. Questions on Commissioners' questions, starting with the Public Staff.

UNIDENTIFIED MALE: No questions.

CHAIR MITCHELL: All right. Attorney General's Office?

MS. FORCE: No questions. Thank you.

CHAIR MITCHELL: Any other intervenors have questions on Commissioners' questions?

(No response.)

CHAIR MITCHELL: All right. Questions on Commissioners' questions from Duke? Ms. Kells?

MS. KELLS: I don't have any questions. Thank you.

CHAIR MITCHELL: All right. Mr. Immel, it looks like you are off the hook for the rest of the day. You may step down.

MS. KELLS: Chair Mitchell, could I just make clear, I'd like for him to be dismissed for the day, but I think he is reserved to be called back later if needed, so not excused yet; is that right?

CHAIR MITCHELL: That is correct. He

may step down, subject to recall.

THE WITNESS: Thank you, Chair Mitchell. Appreciate it.

CHAIR MITCHELL: Thank you, Mr. Immel.

All right. Duke, you may call your next witness.

MR. JEFFRIES: Thank you, Madam Chair. This one is mine. Duke would call Mr. John Spanos to the stand.

CHAIR MITCHELL: All right. Mr. Spanos, there you are.

Whereupon,

JOHN J. SPANOS,

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

CHAIR MITCHELL: All right. Thank you, Mr. Jeffries, you may proceed.

MR. JEFFRIES: Thank you, Madam Chair. Before we start, for the record I'd like to indicate that Mr. Spanos is appearing today on issues related to his direct testimony, which is essentially his depreciation study. He is scheduled to appear again on rebuttal on a panel with Mr. Doss where we expect his testimony to focus on CTR COR related depreciation issues. I just wanted to note that for the record.

CHAIR MITCHELL: All right. Thank you, Mr. Jeffries.

MR. JEFFRIES: Thank you.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Mr. Spanos, can you provide your name and business address to the Commission, please.

A. John J. Spanos. By business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

Q. And where do you work, Mr. Spanos?

A. I work for Gannett Flemming Valuation and Rates.

Q. And what is your position with Gannett Flemming?

A. I am the president of the valuation and rate consultants group.

Q. Thank you. Are you the same John Spanos that prefiled direct testimony in this docket on September 30, 2019, consisting of 19 pages, Appendix A and Spanos Exhibit 1?

A. Yes, I am.

Q. And was that testimony and that exhibit prepared by you or under your direction?

A. Yes, it was.

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

A. I do not.

Q. Mr. Spanos, if I asked you the same questions that are set forth in your prefiled testimony while you were on the stand today, would your answers be the same?

A. Yes, they would.

Q. And, Mr. Spanos, have you prepared a summary of your direct testimony?

A. Yes, I have.

MR. JEFFRIES: Madam Chair, we move that Mr. Spanos' prefiled direct testimony and summary be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Your motion is allowed, Mr. Jeffries.

MR. JEFFRIES: Thank you.

(Whereupon, the prefiled direct testimony and Appendix A and Summary of John J. Spanos' testimony was copied into the record as if given orally from the stand.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING?

A. I have been associated with the firm since college graduation in June 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am President.

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

A. I am testifying on behalf of Duke Energy Carolinas ("DEC" or the "Company").

Q. PLEASE STATE YOUR QUALIFICATIONS.

A. I have 33 years of depreciation experience which includes giving expert testimony in over 300 cases before 40 regulatory commissions, including this Commission. These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have also supervised over 600 other depreciation or valuation assignments. Please refer to Appendix A for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

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

A. My testimony will support and explain the depreciation study conducted under my direction and supervision for the electric utility plant of Duke Energy Carolinas. The study represents all electric plant assets.

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant during service from causes which are known to be in current operation, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. HAVE YOU FILED ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. Attached to my testimony is Spanos Exhibit 1.

Q. WAS SPANOS EXHIBIT 1 PREPARED UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. PLEASE DESCRIBE SPANOS EXHIBIT 1.

A. Spanos Exhibit 1 is a report entitled, "2018 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2018." This report sets forth the results of my depreciation study for DEC.

Q. IS SPANOS EXHIBIT 1 A TRUE AND ACCURATE COPY OF YOUR DEPRECIATION STUDY?

A. Yes.

Q. DOES SPANOS EXHIBIT 1 ACCURATELY PORTRAY THE RESULTS OF YOUR DEPRECIATION STUDY AS OF DECEMBER 31, 2018?

A. Yes.

Q. WHAT WAS THE PURPOSE OF YOUR DEPRECIATION STUDY?

A. The purpose of the depreciation study was to estimate the annual depreciation accruals related to electric plant in service for ratemaking purposes and determine appropriate average service lives and net salvage percentages for each plant account.

Q. PLEASE DESCRIBE THE CONTENTS OF YOUR REPORT.

A. The Depreciation Study is presented in nine parts. Part I, Introduction, presents the scope and basis for the Depreciation Study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining service life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Parts VII, VIII and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account.

The Depreciation Study also includes several tables and tabulations of data and calculations. Table 1 on pages VI-4 through VI-15 of the Depreciation Study presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2018, the book depreciation reserve, and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page VII-2 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-2 presents the results of the net salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2018.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.

A. I used the straight line remaining life method of depreciation, with the average service life procedure for all plant assets except some general plant accounts. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner.

For General Plant Accounts 391.0, 391.1, 393.0, 394.0, 395.0, 397.0, and 398.0, I used the straight line remaining life method of amortization. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historic data from records related to DEC's plant; analyzing these data to obtain historic trends of survivor and net salvage characteristics; obtaining supplementary information from DEC's management, and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to form judgments regarding average service life and net salvage characteristics.

Q. WHAT HISTORIC DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1960 through 2018. The transactions included additions, retirements, transfers and the related balances. The Company records also included surviving dollar value by year installed for each plant account as of December 31, 2018.

Q. WHAT METHOD DID YOU USE TO ANALYZE THIS SERVICE LIFE DATA?

A. I used the retirement rate method. This is the most appropriate method when aged retirement data are available, because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE DEC'S SERVICE LIFE DATA.

A. I applied the retirement rate method to each different group of property in the study. For each property group, I used the retirement rate method to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required to use them as valid considerations in estimating service life. The Iowa-type survivor curves were used to perform these interpretations.

Q. WHAT IS AN "IOWA-TYPE SURVIVOR CURVE" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa type curves are a widely used group of generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 52-R1.5 indicates an average service life of fifty-two years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 1.5, for the mode (possible modes for R type curves range from 1 to 5).

Q. WHAT APPROACH DID YOU USE TO ESTIMATE THE LIVES OF SIGNIFICANT PRODUCTION FACILITIES?

A. I used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described using interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the facility, such as, for a power plant, the retirement of assets such as pumps, motors and piping that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. IS THIS APPROACH WIDELY ACCEPTED FOR ESTIMATING THE SERVICE LIVES OF PRODUCTION FACILITIES?

A. Yes. The life span has been used previously for DEC as well as for Duke Energy Progress. My firm has also used the life span technique in performing depreciation studies presented to many other public utility commissions across the United States and Canada.

Q. HOW ARE THE LIFE SPANS ESTIMATED FOR DEC'S PRODUCTION FACILITIES?

A. The life span estimates are based on informed judgment that incorporates factors for each facility such as the technology of the facility, management plans and outlook for the facility, and the estimates for similar facilities for other utilities. For nuclear and hydro facilities that have operating licenses, the life span estimates are based on the license dates for each facility.

Q. HAVE ANY LIFE SPAN ESTIMATES CHANGED SINCE THE LAST STUDY WAS CONDUCTED?

A. Yes. Allen Units 4 and 5, Cliffside Unit 5 and Marshall Units 1 and 2 have life spans that are planned to be shorter than currently approved. However, given the depreciation rates are developed at the location level for Allen and Marshall, the individual life span dates are not presented in the results section of the Depreciation Study.

Q. ARE THE NEW LIFE SPANS REASONABLE?

A. Yes. The new life spans for Allen is 67 years; Cliffside 5 is 54 years; and Marshall is 69 years. The most common range of life spans for steam production facilities is 55 to 65 years, however, in recent years, originally proposed life spans have been shortened due to unit efficiencies and environmental regulations. The revised or shortened life spans have affected steam facilities that have exceeded the upper limit of the range as well as facilities that have not been in service for 55 years.

Q. ARE THE NEW LIFE SPANS CONSISTENT WITH COMPANY PLANS?

A. Yes. During the conduct of this depreciation study, DEC personnel identified the revised life spans for some steam facilities.

Q. ARE THE FACTORS CONSIDERED IN YOUR ESTIMATES OF SERVICE LIFE AND NET SALVAGE PERCENTS PRESENTED IN SPANOS EXHIBIT 1?

A. Yes. A discussion of the factors considered in the estimation of service lives and net salvage percents are presented in Part III and Part IV of Spanos Exhibit 1.

Q. ARE THERE ANY ASSETS FOR WHICH THERE ARE ADDITIONAL CONSIDERATIONS?

A. Yes. The Company has a program in place to replace its existing legacy electric meters with new technology meters. This replacement project is planned to be completed by the end of 2019. Per the prior case, the net book value ($154 million) of the legacy meters will be amortized over 15 years. Assets that will not be replaced due to this program, such as instrument transformers, remain in Account 370, Metering Equipment and have a 17-L0 survivor curve.

Q. DID YOU PHYSICALLY OBSERVE DEC'S PLANT AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDY?

A. Yes. I made field reviews of DEC's property during April 2019 to observe representative portions of plant. Also, I have conducted field visits in prior studies in October 2003, March 2009, June 2012, December 2016 and January 2017. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. WOULD YOU PLEASE EXPLAIN THE CONCEPT OF "NET SALVAGE"?

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net Salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage.

Inasmuch as depreciation expense is the loss in service value of an asset during a defined period, e.g. one year, it must include a ratable portion of both the original cost and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

For example, the full recovery of the service value of a $1,000 line transformer will include not only the $1,000 of original cost, but also, on average, $75 to remove the line transformer at the end of its life and $25 in salvage value. In this example, the net salvage component is negative $50 ($25 - $75), and the net salvage percent is negative 5% (($25 - $75)/$1,000).

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. The net salvage percentages estimated in the Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided to me by the Company's operating personnel, general knowledge and experience of industry practices; and trends in the industry in general. The statistical net salvage analyses incorporate the Company's actual historical data for the period 2003 through 2018, and considers the cost of removal and gross salvage ratios to the associated retirements during the 16-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Q. WERE THE NET SALVAGE PERCENTAGES FOR GENERATING FACILITIES BASED ON THE SAME ANALYSES?

A. Yes, for the interim net salvage estimates. The net salvage percentages for generating facilities were based on two components, the interim net salvage percentage and the final net salvage percentage. The interim net salvage percentage is determined based on the historical indications from the period 2003 to 2018 of the cost of removal and gross salvage amounts as a percentage of the associated plant retired. The final net salvage or dismantlement component was determined based on the retirement activities associated with the assets anticipated to be retired at the concurrent date of final retirement.

Q. HAVE YOU INCLUDED A DISMANTLEMENT OR DECOMMISSIONING COMPONENT INTO THE OVERALL RECOVERY OF GENERATING FACILITIES?

A. Yes. A dismantlement or decommissioning component has been included to the net salvage percentage for steam, hydro and other production facilities.

Q. CAN YOU EXPLAIN HOW THE FINAL NET SALVAGE COMPONENT IS INCLUDED IN THE DEPRECIATION STUDY?

A. Yes. The dismantlement component is part of the overall net salvage for each location within the production assets. Based on studies for other utilities and the cost estimates of DEC, it was determined that the dismantlement or decommissioning costs for steam and other production facilities is best calculated by dividing the dismantlement cost by the surviving plant at final retirement. These amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location. The detailed calculations of the overall net salvage for each location is set forth on page VIII-3 of the Depreciation Study.

Q. WHAT IS THE BASIS OF THE DISMANTLEMENT OR DECOMMISSIONING COST ESTIMATES?

A. The decommissioning cost estimates are based on decommissioning studies of each generating site performed by Burns and McDonnell. These estimates are based on the current cost to decommission the facility. However, the costs to decommission power plants has tended to increase over time (as have construction costs in general). For this reason, to recover the full decommissioning costs for each site, these costs need to be escalated to the time of retirement. The calculations of the escalation of these costs have been provided in the table set forth on pages VIII-4 and VIII-5 of the Depreciation Study.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each depreciable group based on the straight line remaining life method, using remaining lives weighted consistent with the average service life procedure. The calculation of annual depreciation accrual rates was developed as of December 31, 2018.

Q. PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING.

A. Amortization accounting is used for accounts with many units, but small asset values. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period which represents an anticipated life during which the asset will render service. For example, in amortization accounting, assets that have a 20-year amortization period will be fully recovered after 20 years of service and taken off the Company books, but not necessarily removed from service. In contrast, assets that are taken out of service before 20 years remain on the books until the amortization period for that vintage has expired.

Q. AMORTIZATION ACCOUNTING IS BEING IMPLEMENTED FOR WHICH PLANT ACCOUNTS?

A. Amortization accounting is only appropriate for certain General Plant accounts. These accounts are 391.0, 391.1, 393.0, 394.0, 395.0, 397.0, and 398.0, which represent slightly more than one percent of depreciable plant.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE THE DEVELOPMENT OF THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IN YOUR DEPRECIATION STUDY.

A. I will use Account 367, Underground Conductors and Devices, as an example because it is one of the largest depreciable groups.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data were compiled from 1960 through 2018 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1960-2018 and 1999-2018 experience bands are presented in the depreciation study on pages VII-174 through VII-177. Each life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-174 of Spanos Exhibit 1, shows $2,958,938 retired during age interval 0.5-1.5 with $1,850,177,520 exposed to retirement at the beginning of the interval. Consequently, the retirement ratio is

0.0016 ($2,958,938/$1,850,177,520) and the survivor ratio is 0.9984 (1-0.0016). The life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 55-R3, on page VII-173 of Spanos Exhibit 1.

The net salvage percent is presented on page VIII-40. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 2003 through 2018. The 16-year period experienced $7,562,257 ($6,188,866-$13,751,123) in net salvage for $46,009,334 plant retired. The result is negative net salvage of 16 percent ($7,562,257/$46,009,334) on the statistics for this account as well as the three-year rolling averages and trend in recent years, the recommended net salvage for underground conductor is negative 20 percent

My calculation of the annual depreciation related to original cost of electric utility plant at December 31, 2018 for Account 367 is presented on pages IX-202 and IX-203 of Spanos Exhibit 1. The calculation is based on the 55-R3 survivor curve, 20% negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to Table 1 on page VI-12.

Q. IN YOUR OPINION, ARE THE DEPRECIATION AND AMORTIZATION RATES SET FORTH IN SPANOS EXHIBIT 1 THE APPROPRIATE RATES FOR THE COMMISSION TO ADOPT IN THIS PROCEEDING FOR DEC?

A. Yes. These rates appropriately reflect the rates at which the costs of DEC's assets are being consumed over their useful lives. These rates are an appropriate basis for setting electric rates in this matter and for the Company to use for booking depreciation and amortization expense going forward.

Q. HAVE YOU DEVELOPED DEPRECIATION RATES FOR FUTURE ASSETS?

A. Yes. There are plans to add a new Clemson Heat and Power Generating facility. The rates for these assets will be based on interim survivor curves for each account, a weighted net salvage percent for each account and a 40-year life span for the location. Additionally, depreciation rates for new battery storage assets for generation, transmission and distribution have been included. These assets are based on a 15-L3 survivor curve and zero percent net salvage. Each of these future rates are presented on page VI-15 of Spanos Exhibit 1.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Appendix A

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013 and February 2018.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December, 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso

Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee- American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire and Newtown Artesian Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana

Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER-03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	FERC		Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.		Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	ISO82, ETC. AL	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	09-	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC		Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC		Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	2011-2232243	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
153.	2012	TX PUC		Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13- -0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13- -0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14-	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Commission	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC		Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER17- _	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	Docket Nos. ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-19 / UG-19	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-	City of Lancaster	Depreciation
321.	2019	IURC		Duke Energy Indiana	Depreciation
322.	2019	FERC	Docket No. ER-______	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation

Duke Energy Carolinas, LLC
Summary of Direct Testimony of John Spanos
Docket No. E-7, Sub 1214

My name is John Spanos and I am President of Gannett Fleming Valuation and Rate Consultants, LLC, an international energy and regulatory consulting firm. I am an expert in depreciation and have more than 34 years of experience in conducting depreciation studies for the various clients of my firm, including in these dockets Duke Energy Carolina, LLC and Duke Energy Progress, LLC. I have testified before this Commission on multiple prior occasions and have prepared depreciation studies for and on behalf of regulated utilities on depreciation related issues hundreds of times. The purpose of my Direct Testimony in this docket is to present the Depreciation Studies I conducted for DEC for purposes of these rate cases, which is attached to my testimony as Spanos Exhibit 1.

In calculating depreciation expense for DEC, along with the subcomponent calculations and analyses that support such depreciation expense (such as probable retirement dates, service life, survivor curves, accrued depreciation, and net salvage), I used widely accepted depreciation methodologies adopted to the specific circumstances of DEC. These methodologies have been previously accepted by this Commission in prior cases and are the prevailing methods accepted by the majority of State Public Service Commissions that engage in evaluating depreciation expense for regulated utilities.

The precise methodologies used to calculate depreciation rates and depreciation expense for DEC is set forth in my Direct Testimony and in the Depreciation Study attached to my testimony.

MR. JEFFRIES: Thank you. And we'd also move that Mr. Spanos' Exhibit 1 be identified as marked.

CHAIR MITCHELL: It shall be so marked.

(Spanos Exhibit 1 was identified as it was marked when prefiled.)

MR. JEFFRIES: Thank you, Madam Chair. Mr. Spanos is available for cross examination and questions by the Commission.

CHAIR MITCHELL: All right. Public Staff, you may proceed.

MR. DODGE: Thank you, Chair Mitchell. Can you hear me okay?

CHAIR MITCHELL: We can, Mr. Dodge.

MR. DODGE: Thank you.

CROSS EXAMINATION BY MR. DODGE:

Q. Good afternoon, Mr. Spanos.

A. Good afternoon.

Q. I'm Tim Dodge with the Public Staff. The bulk of my questions today will be on the depreciation study, as Mr. Jeffries indicated. But, actually, the bulk of my questions will be when you return for rebuttal next. But there was one specific topic in your depreciation and depreciation study that was included as Exhibit 1 with your testimony that I'd like to discuss. Do you have a copy of that Exhibit 1 with you?

A. I do.

Q. All right. Could you turn to page 262? I'll give you a moment to turn there.

A. Excuse me, my document doesn't have those specific pages. Would you be able to reference the bottom Roman numeral pages that maybe able -- I'd be able to get to it quicker that way?

Q. Yes. It's Roman numeral VII-193. This is the survivor curve for account 370.02.

A. Yes, I'm there. Thank you.

Q. Okay. And again, this is the survivor curve for account 370.02, which is meters-utility of the future, correct?

A. That's correct.

Q. And just to kind of set the stage here, this is the generalized survivor curve for the AMI meter deployment for DEC; is that correct?

A. That's correct.

Q. And the curve is labeled as Iowa 15-S 2.5. And just to kind of make sure I understand the terminology indicated in that label, so the 15 in that

Iowa survivor curve indicates it's a 15-year estimated average service life for this equipment; is that correct?

A. That is correct.

Q. And then the S label in the curve means that the curve is symmetric. So, you know, among other attributes, that indicates that, in general, half of the assets are going to be retired prior to the average life, and an equal number would be retired after the average term is reached; is that correct?

A. I think that's a fair way to portray the curve. It is a dispersion curve and anticipates retirements happening in multiple ages, yes. And I think, as you can see, the X axis has a 15 and reaches 50 percent surviving at that point, so it's consistent with what you described.

Q. All right. Thank you. And now, if you could turn to the next page, 263, or VII-194. This is the original --

A. Yes.

Q. This is the original life table that supports the survivor curve we were just discussing, or been represented on that survivor curve as well; is that correct?

A. This represents the actual data and exposures that were available at each age interval. That's what that represents. The smooth survivor curve is the estimation of the life characteristics. So you have a life table, which is the original curve, and then the smooth curve is the representation of what is expected for the most appropriate life characteristics of that asset class.

Q. Okay. And that's exactly what I'm going to talk a little bit about, was the data supporting the life table, or indicated in the life table here.

So looking at the life table and the age intervals, would you agree that the oldest age interval indicated on the table is 8.5 years, which represents the first AMI meters placed in service by DEC?

A. You are correct that the -- in general, 8.5 is the initial assets that were placed in service in this asset class.

Q. Right. And again, so this table, from your depreciation study, indicates that, as of December 31, 2018, that the value or the exposure for each of those age intervals for this property group; is that correct?

A. That is correct.

Q. And the table in the middle, or the blank column in the middle, retirements during age interval, that's blank.

What does that signify, the fact that that column in the middle is empty?

A. Based on the assets and their property units, there have -- that represents retirements during each age interval. And for the first eight and a half years, we've not had any recorded retirements for each of these age intervals.

Q. All right. And so if you could turn back to the survivor curve on page 262. Do you have that in front of you?

A. Yes. I do, yes.

Q. Okay. And so that the retirements during the age interval, that information is indicated -- or I should say actually the survivor ratio is indicated in the dashed line along the top of that table, basically at 100 percent across the top there?

A. There are actually little squares at each age interval, but you are correct that the -- that represents the original survivor curve that we've seen so far. And, obviously, what this tells the viewer and those reviewing that is that this is a very young account, that we've had very little opportunity to utilize statistical analysis to determine our estimate, and informed judgment is required for this new technology or new type of asset class.

Q. All right. Thank you. Under the curve, though, wouldn't you expect your 8.5 where we're at for some of these oldest-age intervals, some portion of the AMI meter cost to be indicated as retired?

A. Well, again, we're using judgment, and the expectation is for this asset class, yes, at age eight and a half, we would -- based on our information, and judgment, and industry information, we would expect about 10 percent or maybe 8 percent of the investment to have been retired at this point in time. However, you know, that does not necessarily mean that you will not get retirements; it's very possible that, at age 10, maybe we'll have 20 percent retirements based on the new technology.

So you can't -- when you're doing this, you have to take into consideration informed judgment, which includes what others in the industry are doing and what they expect for these types of assets. So the smooth curve isn't an extrapolation of what we anticipate, and when you have a very short time period and very limited information, the fact that the smooth curve does not match the actual data should not be a surprise. I would have expected within -- when I see others in the industry, when they get to age nine, that there would have been some experienced retirements. We have not seen that yet for these assets.

Q. All right. And so just to confirm that point you just made. The depreciation study presented no data indicating a retirement of any of these AMI assets in this account at this time?

A. There have not been any experienced as of December 31, 2018. And again, a 15-year average was consistent with what was utilized in the last study and is the most commonly utilized average service life for these types of assets in the industry.

Q. Thank you, Mr. Spanos. I have no further questions.

A. Thank you.

CHAIR MITCHELL: All right. The Attorney General's Office, Ms. Force?

MS. FORCE: No questions. Thank you.

CHAIR MITCHELL: Okay. Sierra Club, I believe it's you, Ms. Lee?

MS. LEE: No questions, Chair Mitchell.

Thank you.

CHAIR MITCHELL: All right. Any additional cross examination for the witness?

(No response.)

CHAIR MITCHELL: Any redirect, Mr. Jeffries?

MR. JEFFRIES: I don't think so, Madam Chair.

CHAIR MITCHELL: Okay. Questions from Commissioners. Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: No questions.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yes. Mr. Jeffries, I didn't hear you very clearly. Could you say again the topics that you're going to bring Mr. Spanos back on rebuttal? What are those topics? You're on mute.

MR. JEFFRIES: I'm sorry, how about now?

CHAIR MITCHELL: We can hear you.

MR. JEFFRIES: Okay. I think I was

pushing the wrong button on my computer, my apologies. Commissioner Clodfelter, Mr. Spanos will be appearing on DEC's rebuttal case on a panel with David Doss. And the anticipated subject of that testimony revolves around the depreciation-related aspects of CCR costs of remediation, which is a subject that only appears in his rebuttal testimony.

COMMISSIONER CLODFELTER: Thank you for the clarification. I just didn't hear you the first time.

Madam Chair, actually, I did have some questions for Mr. Spanos on that topic, based on pages 26 through 36 of his direct testimony, but I'd rather not ask my questions in separate bites. And so if, it's okay with Mr. Jeffries, I'll just hold all my questions for the panel when Mr. Spanos comes back. I'd just like to make sure he understands that some of my questions will be based on pages 26 through 36 of his direct testimony, which cover the topic of depreciation for CCR assets.

CHAIR MITCHELL: All right. Thank you, Commissioner Clodfelter.

Commissioner Duffley?
COMMISSIONER DUFFLEY: I do not have any questions. Thank you.
CHAIR MITCHELL: Commissioner Hughes?
COMMISSIONER HUGHES: No questions. Thank you.
CHAIR MITCHELL: Okay. And Commissioner McKissick?
COMMISSIONER McKISSICK: No questions at this time.
CHAIR MITCHELL: All right. Mr. Spanos, you are -- there is nothing further for you this afternoon. You may step down, and you will be recalled later in the proceeding.
THE WITNESS: Okay. Thank you very much. Appreciate your time.
CHAIR MITCHELL: Thank you, sir.
All right. Duke, you may call your next witnesses.
MS. DOWNEY: Thank you, Chair Mitchell.
CHAIR MITCHELL: I'm sorry, I believe -- Mr. Jeffries, did you have a motion?
MR. JEFFRIES: I did. We would move Mr. Spanos' Exhibit 1 into evidence, Madam Chair.

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

(Spanos Exhibit 1 was admitted into evidence.)

CHAIR MITCHELL: All right. I'm sorry, Ms. Downey, did you have a question for me? Okay.

All right. Duke, you may call your next witnesses.

MS. JAGANNATHAN: Thanks, Chair Mitchell. Again, this is Molly Jagannathan, and I represent Duke Energy Carolinas. And at this time we would like to call the panel of Janice Hager, Michael Pirro, and Lon Huber to the stand to testify as a panel.

CHAIR MITCHELL: Okay. Let's go ahead and get them under oath. Let's see, I see Mr. Huber, I saw Ms. -- and I see Mr. Pirro and Ms. Hager. I saw you momentarily, and you are no longer on my screen. Let's see.

MS. JAGANNATHAN: Ms. Hager, I think you just need to turn your camera on.

(Pause.)

MS. JAGANNATHAN: Madam Chair, if you

don't mind, I'll just check on her and make sure she's not having technical difficulties.

CHAIR MITCHELL: Okay. Please do so.

(Pause.)

MS. JAGANNATHAN: Chair Mitchell, if you don't mind, if we just take a couple-minute recess, I'll make sure to get her camera turned on. I'm unable to reach her right now.

CHAIR MITCHELL: Okay. Why don't we take a five-minute recess here for the witness. We'll go back on -- we'll go off the record now. We'll go back on at 4:05.

MS. JAGANNATHAN: Great. Thank you, Chair Mitchell, I apologize.

(At this time, a recess was taken from 4:00 p.m. to 4:05 p.m.)

CHAIR MITCHELL: We'll go back on the record. Let me check in with my court reporter. Joann, are you ready? Okay. Perfect. All right, Ms. Jagannathan, you may proceed. Let's go ahead and get your witnesses under oath before I turn them back over to you.

Whereupon,

JANICE HAGER, MICHAEL J. PIRRO, AND LON HUBER,

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

CHAIR MITCHELL: All right. Thank you. For the purposes of -- for the sake of those who are viewing this today, Ms. Hager is sitting behind the name tag of Monica Smith.

All right. Ms. Jagannathan, you may proceed.

MS. JAGANNATHAN: Thanks, Chair Mitchell. Sorry we had to do another laptop shuffle. So I think we're all set.

DIRECT EXAMINATION BY MS. JAGANNATHAN:

Q. Ms. Hager, would you state your name and business address for the record?

A. (Janice Hager) My name is Janice Hager. My business address is 2049 Mount Zion Church Road, Alexis, North Carolina 28006.

Q. Thank you. And can you let us know by whom you are employed and in what capacity?

A. I am president of Janice Hager Consulting, LLC.

Q. And on September 30, 2019, did you cause to be prefiled in this docket direct testimony consisting of 19 pages?

A. I did.

Q. And did you also cause to be filed, corrected direct testimony consisting of 18 pages on February 14, 2020?

A. I did.

Q. On March 4, 2020, did you cause to be prefiled in this docket, rebuttal testimony --

(Reporter interruption due to technical difficulties.)

CHAIR MITCHELL: All right. We will pause for the court reporter. Just let me know, Joann, when you're back up.

(Pause.)

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

MS. JAGANNATHAN: Madam Court Reporter, did you need me to back up and repeat anything, or should we just pick up where we left off?

COURT REPORTER: You can just pick up where you left off. Thank you.

Q. Ms. Hager, on March 4, 2020, did you cause to be prefiled in this docket, rebuttal testimony consisting of 24 pages?

A. I did.

Q. And on April 6, 2020, did you cause to be prefiled in this docket, supplemental rebuttal testimony consisting of four pages?

A. I did.

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

A. Yes. I have two changes to my rebuttal testimony, which are included in the errata page provided with my testimony summary.

Q. Great. Thank you. And with the corrections to your rebuttal testimony that are noted in your errata, if I asked you the same questions here today, would your answers be the same?

A. Yes, they would.

MS. JAGANNATHAN: Chair Mitchell, I would move that Ms. Hager's prefiled corrected direct testimony, her rebuttal testimony as corrected by the errata page and her supplemental rebuttal testimony be entered into the record as if given orally from the stand.

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

(Whereupon, the prefiled corrected direct, rebuttal, and supplemental rebuttal testimony of Janice Hager were copied into the record as if given orally from the stand.)

I. INTRODUCTION AND PURPOSE

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

A. My name is Janice Hager, and my business address is 2049 Mount Zion Church Road, Alexis, North Carolina. I am President of Janice Hager Consulting, LLC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have extensive experience with Duke Energy Corporation ("Duke Energy") over a 34-year career with the Company. I am a civil engineer, having received a Bachelor of Science in Engineering from the University of North Carolina at Charlotte. During my time at Duke Energy, I was a registered professional engineer in North Carolina and South Carolina. I worked in Duke Power's (now Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company")) Rates and Regulatory Affairs area for ten years, the last three of which I was Vice President of the department. Following the merger of Duke Energy and Progress Energy, Inc., I led Duke Energy's integrated resource planning process for all of the Company's regulated utilities, including Duke Energy Carolinas, LLC ("DE Carolinas") and Duke Energy Progress ("DE Progress"). At the time of my retirement in December 2014, I was Vice President of Integrated Resource Planning and Analytics for Duke Energy.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have filed testimony and appeared before this Commission many times including on matters of Fuel Adjustment Clauses, Integrated Resource Planning, Certificates of Public Convenience and Necessity, general rate cases, and other issues. I most recently testified before this Commission in the most recent general rate case in Docket No. E-7, Sub 1146. I have also appeared before the Public Service Commission of South Carolina, the Indiana Utilities Regulatory Commission, and the Federal Energy Regulatory Commission ("FERC").

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

A. My testimony describes and supports the allocation of DE Carolinas' electric operating revenues and expenses and original cost rate base assigned to the North Carolina retail jurisdiction and to each customer class according to the cost of service studies performed by the Company.

II. <u>COST OF SERVICE STUDY OVERVIEW</u>

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A. The purpose of a cost of service study is to align the total costs incurred by DE Carolinas in the test period with the jurisdictions and customer classes responsible for the costs. The study directly assigns or allocates the Company's revenues, expenses, and rate base among the regulatory jurisdictions and customer classes served by the Company based upon the service requirements of those respective jurisdictions and customer classes. These service requirements are based on several factors, including differences in usage patterns and size.

Cost causation is a key component in determining the appropriate assignment of revenues, expenses, and rate base among jurisdictions and customer classes. Under the principle of cost causation, costs are assigned to the specific jurisdictions and customer classes that "caused" such costs to be incurred.

Once all costs and revenues are assigned, the study identifies the return on investment the Company has earned for each customer class during the test period. These returns can then be used as a guide in designing rates to provide the Company an opportunity to recover its costs and earn its allowed rate of return.

Q. SHOULD THE COST OF SERVICE STUDY FULLY ALLOCATE COSTS AMONG JURISDICTIONS AND CUSTOMER CLASSES?

A. Yes. As the cost of service study is used as a guide in designing rates, all costs must be allocated to the appropriate jurisdiction and customer class. If any costs are omitted or remain unallocated then the utility's rates will not allow for full recovery of the Company's operating expenses, including its approved cost of capital.

III. REVIEW OF DE CAROLINAS' COST OF SERVICE STUDY

Q. HAVE YOU REVIEWED THE COST OF SERVICE STUDIES PREPARED BY DE CAROLINAS FOR FILING IN THIS CASE?

A. Yes. As referenced by Witness McManeus in her pre-filed direct testimony, I have reviewed DE Carolinas' cost of service studies that were prepared and filed as Item 45 in the Company's Form E-1 filing in this case.

Q. WHAT IS THE SOURCE OF THE COST COMPONENTS THAT ARE REFLECTED IN DE CAROLINAS' COST OF SERVICE STUDY USED TO SUPPORT THE REQUESTED RATE INCREASE?

A. The cost of service study is based on the official accounting books and records of DE Carolinas, supported in this proceeding by Company witness Speros. The cost components are comprised of the Company's electric operating expenses and original cost rate base and are based on the historical 12-month period covering January 1, 2018 through December 31, 2018 (the "Test Period").

IV. COST OF SERVICE STUDY PREPARATION

Q. PLEASE EXPLAIN HOW COSTS WERE ASSIGNED TO THE DIFFERENT JURISDICTIONS AND CUSTOMER CLASSES IN THE COST OF SERVICE STUDY IN SUPPORT OF THIS RATE CASE.

A. Generally, there are three key activities which occur when assigning costs in a cost of service study:

A. Costs are grouped according to their "function." Functions include production (generation), transmission, distribution, and customer service, billing, and sales.

B. Functionalized costs are then grouped or classified based on the utility "operation" or service being provided and the related causation of the costs. Typical classifications include demand, energy, and customer-related costs.

C. Finally, the costs, which have been functionalized and classified, are allocated or directly assigned to the proper jurisdiction and customer class based on the way the costs are incurred (*i.e.*, based on cost causation principles).

A. Functionalizing Costs

Q. PLEASE EXPLAIN HOW TO FUNCTIONALIZE COSTS.

A. The Company accounts for its costs using the Uniform System of Accounts ("USOA") of the FERC. The USOA assigns the costs of the Company's plant investment into the primary categories of production (generation), transmission, distribution, and general and intangible plant. Similarly, the USOA categorizes the Company's operating costs into production, transmission, distribution, customer services, and administrative and general functions.

B. Classifying Costs

Q. PLEASE EXPLAIN HOW COSTS ARE CLASSIFIED.

A. Functionalized costs are classified according to their cost-causation characteristics. These characteristics are typically defined as demand-related, energy-related, or customer-related.

Q. PLEASE DEFINE DEMAND-RELATED COSTS.

A. Demand-related costs are costs incurred that vary in direct relationship to the kilowatts ("kW") of demand that customers place on the various segments of the system. Costs that are classified as demand-related include major portions of the Company's investment and related expenses in its production and transmission facilities and a significant portion of the investment and related expenses of its distribution system. These costs tend to remain constant over the short run and do not change based on the amount of energy consumed. These costs are often referred to as fixed costs.

Q. PLEASE DEFINE ENERGY-RELATED COSTS.

A. Energy-related costs are costs incurred that vary in direct relationship to the amount of energy or kilowatt hours ("kWh") generated and delivered. These costs are often referred to as variable costs.

Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

A. Customer-related costs are costs incurred as a result of the number of customers being served. Customer costs do not vary with the customers' volume of usage but are related to the number of customers.

C. Allocation and Direct Assignment of Costs

Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED AND DIRECTLY ASSIGNED.

A. Cost components identified as having a direct relationship to a jurisdiction or customer class are directly assigned to that jurisdiction or class before any allocations occur. For example, many distribution-related costs are directly assigned to a jurisdiction based on their state location. For these costs and for the remaining unassigned costs, specific allocation factors are developed that relate to the (1) demand, (2) energy, and (3) customer-related classifications identified above.

1. Demand Allocators

Q. WHAT DEMAND ALLOCATORS ARE USED TO ASSIGN DEMAND COSTS TO JURISDICTIONS AND CUSTOMER CLASSES IN THIS CASE?

A. There are two categories of demand-related costs used in the cost of service study:

a. <u>Production & Transmission Demand</u> – Production & Transmission demand costs are allocated using the Summer Coincident Peak ("SCP") method.

b. <u>Distribution Demand</u> – Distribution plant investments are directly assigned to the jurisdictions. At the customer class level, substations, and a part of poles, lines and transformers that have been designated as demand-related are allocated based on the Non-Coincident Peak Demand ("NCP").

a. Production and Transmission Costs

Q. PLEASE EXPLAIN THE CONCEPT OF ALLOCATING COSTS BASED ON COINCIDENT PEAK.

A. A coincident peak ("CP") allocator assigns the fixed demand-related costs (for example, a portion of production and all transmission-related costs) to the jurisdictions and customer classes in proportion to their respective contribution to the system's peak hourly demand during the Test Period. Each jurisdiction and customer class' cost responsibility (*i.e.*, the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. The cost of service study supporting the Company's proposed rate design in this proceeding allocates the fixed portion of production and transmission demand-related costs based upon a jurisdictions and customer class' coincident peak responsibility occurring during the summer, otherwise known as the Summer Coincident Peak or SCP Allocator.

Q. WHEN DID THE SUMMER COINCIDENT PEAK DEMAND USED IN THIS STUDY OCCUR?

A. The DE Carolinas' summer peak generation and transmission demand used in this study occurred on June 19, 2018 at the hour ending 5:00 PM.

Q. WHAT WAS THE 2018 SUMMER PEAK FOR 2018?

A. The DE Carolinas system summer peak was 17,632 MWs.

Q. IS THE PEAK JUST DESCRIBED THE SAME ONE USED IN THE COST OF SERVICE STUDIES?

A. No. The DE Carolinas' system peak is adjusted when developing production demand allocators for the cost of service. These adjustments include a pro forma adjustment to exclude the demand for three wholesale customers whose contracts expired at the end of 2018, along with other adjustments such as adding the demands associated with two backstand arrangements.

Q. WAS THE 2018 SUMMER PEAK ALSO THE SYSTEM PEAK FOR 2018?

A. No. The DE Carolinas system peak occurred on January 5th in the hour ending 8:00 AM. This DE Carolinas system peak was 18,935 MWs. Given that the Company's generation and transmission investments being considered for cost recovery in this case were made based on summer peak planning, for consistency we have continued to use the summer peak for cost allocation. However, Mr. Pirro has given some consideration to the winter peak in rate design.

Q. WAS THE SUMMER CP TYPICAL WHEN COMPARED TO OTHER SUMMER CPs?

A, Yes. In 21 of the last 25 years, the Company's coincident peak occurred in the months of June through August. In 23 of the last 25 years, the summer peak occurred between hour ending 3:00 PM and hour ending 5:00 PM. The 2018 summer peak is within the range of these past occurrences and it is therefore appropriate to assign fixed demand-related costs to the Company's jurisdictions and customer classes based upon the SCP.

b. Distribution Costs

Q. HOW ARE DISTRIBUTION COSTS ALLOCATED?

A. Most distribution investments are first identified and directly assigned to the state in which they are located. Then those distribution costs identified as customer-related are allocated based on customer allocation factors, as discussed below. The remainder of the distribution costs are designated as demand-related and allocated to the customer classes based on NCP demand allocators.

The NCP allocators are developed by taking the ratio of the non-simultaneous peak demands of the customers in each class whenever that peak occurred during the test period and comparing that to the sum of all customers' non-simultaneous peak demand. Several different NCP allocators are developed to account for the different levels of the distribution system where customers may take service (primary and below, secondary, etc.). For example, only the NCP demand of customers who take service at secondary voltage are included in the development of the NCP allocator used to allocate secondary distribution lines and poles.

Q. WHY IS A NON-COINCIDENT PEAK USED FOR ALLOCATING DEMAND-RELATED DISTRIBUTION INVESTMENT?

A. Distribution facilities serve individual neighborhoods, rural areas, and commercial districts. They do not function as a single integrated system in meeting system peak demand. Instead, the distribution system serving each neighborhood, rural area, or commercial district must be able to meet the peak demand in the area it serves whenever the peak occurs. Accordingly, contribution to NCP is the appropriate measure of determining customers' responsibility for these costs because it best measures the factors that drive investment to support that part of the system.

2. Energy Allocators

Q. WHAT ALLOCATOR WAS USED TO ASSIGN ENERGY-RELATED COSTS TO JURISDICTIONS AND CUSTOMER CLASSES?

A. Energy-related costs reflect the variable cost of producing, transmitting, and delivering electricity. Examples of costs allocated on this basis are fuel costs and variable production costs incurred at generating stations. DE Carolinas' kWhs of generation and deliveries during the Test Period have been used to allocate these variable costs. The kWh sales information is collected, and then adjusted for the level of losses attributable to each class and jurisdiction, to derive the level of kWhs at the generator attributable to that class or jurisdiction.

3. Customer Allocators

Q. WHAT TYPES OF COSTS HAS DE CAROLINAS INCLUDED FOR ALLOCATION AS CUSTOMER-RELATED?

A. DE Carolinas has included operating expenses in FERC accounts 901-917. These expenses include meter reading, billing and collection, and customer information and services. In addition, DE Carolinas has included in this category a portion of distribution costs that the Company has identified as customer-related, including the costs of the service drop and meter (FERC Accounts 369-370) and a portion of the costs for distribution lines, poles, and transformers (FERC Accounts 364-368).

Q. DO YOU BELIEVE INCLUSION OF A PORTION OF DISTRIBUTION LINE, POLE, AND TRANSFORMER COSTS IN CUSTOMER ALLOCATIONS IS REASONABLE AND APPROPRIATE?

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("CAM") states that a portion of distribution costs related to FERC Accounts 364-368 are customer-related. These FERC accounts include the costs of poles, towers, fixtures, overhead and underground conductors, and transformers. The two-methods the CAM discusses for allocating these customer-related distribution costs are:

1) Minimum System Method (called Minimum-Size Method in the NARUC Manual); and

2) Zero-Intercept Method (called Minimum-Intercept Method in the NARUC Manual).

Both methods recognize that some portion of the distribution system is necessary to serve customers, regardless of whether the customers take any energy from the system. The Minimum System Method seeks to determine the minimum size distribution system that can be built to serve the minimum loading requirements of customers. The Minimum System Method develops the cost of the minimum set of distribution assets that would be needed to serve customers and allocates those costs based on the number of customers.

Similar to the Minimum System Method, the Zero-Intercept Method allocates a portion of the same distribution accounts on the basis of the number of customers. The Zero-Intercept method seeks to identify the portion of distribution plant that is associated with no load using regression techniques.

Q. WHICH METHOD DID DE CAROLINAS CHOOSE AND WHY?

A. DE Carolinas incorporated the concept of Minimum System into its COS Study for allocating costs to customers, which is appropriate for allocation of customer-related distribution costs. The zero-intercept method is generally considered to be a more complex and time-consuming methodology that often can produce results that are not materially different from the Minimum System method. The theory behind use of a minimum system study is sound and consistent with cost causation, which is the foundation of COS studies. DE Carolinas' Minimum System Study allowed DE Carolinas to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels). Every customer requires some minimum amount of wires, poles, transformers, etc. to receive service; therefore, every customer "caused" DE Carolinas to install some amount of such distribution assets. The concept DE Carolinas used to develop its Minimum System Study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb). This methodology allows the utility to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, if and when the customer chooses to use electricity. Once minimum system costs have been identified, all distribution costs over the minimum system costs and direct assignments are determined to be driven by demand.

Q. WHAT IS THE BASIC CUSTOMER METHOD AND WHY DID THE COMPANY CHOOSE NOT TO USE THIS METHOD?

A. The Basic Customer Method is not included in the CAM, but has been advocated by intervening parties participating in recent general rate cases. The Basic Customer Method classifies 100% of all poles, wires, and line transformers as demand-related costs. All other costs (those related to meters and service connections) are classified as customer-related. This method produces lower allocation to customer-related costs and thus, in rate design, a lower fixed customer charge. As mentioned previously, all costs are allocated; the issue is which are designated demand-related, energy-related, or customer-related. By designating a lower amount as customer-related, the Basic Customer method necessarily allocates more costs to the demand-related portion of distribution costs. A higher allocation to demand-related costs means higher demand charges for customers whose electric rate includes demand charges and higher energy charges for those without demand charges. Without the use of the Minimum System allocation methodology, low use customers avoid paying for the infrastructure necessary to provide service to them which is counter to cost causation principles.

Q. HAVE YOU REVIEWED THE PUBLIC STAFF'S REPORT ON THE MINIMUM SYSTEM METHODOLOGY FILED IN DOCKET NO. E-100, SUB 162 ON MARCH 28, 2019?

A. Yes. I have reviewed the report. The Public Staff concluded that the use of the Minimum System Method for classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic facilities charge.[1]

Q. WHAT ARE YOUR IMPRESSIONS OF THE PUBLIC STAFF'S REPORT?

A. I observe that the Public Staff recognizes that the NARUC CAM "continues to be considered an important resource for the calculation and allocation of electric utility cost of service for regulatory commissions, consumer advocates, and parties before the Commission testifying on issues of cost-of-service and rate design."[2] I also observe that the Public Staff agrees with the Company that distribution related costs have both demand-related and fixed

[1] Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, March 280, 2019, Docket No. E-100, Sub 162, p 16-17.
[2] Ibid, p. 4.

characteristics. The Public Staff concludes that "[w]hile distribution related costs must be sized to meet some level of maximum demand, there is also a minimum cost for the distribution system that must be incurred regardless of demand."[3] (Emphasis in original.)

The Public Staff also has several observations regarding setting the Basic Facilities Charge. For example, the Public Staff differentiates between the considerations in a COSS and Rate Design, the latter of which the Public Staff states should take additional things in consideration such as policy objectives and appropriate price signals. Similar to Public Staff, I believe it is appropriate to keep a COSS free of biases and focus on cost causation.

4. Conclusion on Allocation Methodology

Q. ARE THE COMPANY'S CHOSEN METHODOLOGIES TO ALLOCATE ITS DEMAND-RELATED, ENERGY-RELATED AND CUSTOMER-RELATED COSTS REASONABLE AND APPROPRIATE UNDER THE CIRCUMSTANCES?

A. Yes. They are.

V. CONCLUSION

Q. DOES THE COMPANY'S COST OF SERVICE STUDY USED FOR THIS CASE PROPERLY DISTRIBUTE COSTS OF PROVIDING ELECTRIC SERVICE TO CUSTOMER CLASSES?

A. Yes. It does. The cost of service study provides a proper foundation for distributing costs among the jurisdictions and customer classes because it

[3] Ibid, p. 8.

recognizes cost causation and distributes costs accordingly. This study also provides a proper basis for determining cost-based rates and is a major component of fair and equitable rate design. The cost of service study also provides an accurate measure of profitability among classes of customers.

Q. DID YOU VERIFY THAT THE COST OF SERVICE INFORMATION YOU ARE TESTIFYING TO WAS USED IN DETERMINING HOW TO DESIGN PROPOSED RATES?

A. Yes. The North Carolina retail cost of service information, including the separation of the demand, energy, and customer components of cost, was used in developing the rate design proposed by DE Carolinas.

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

A. Yes.

I. INTRODUCTION AND PURPOSE

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

A. My name is Janice Hager, and my business address is 2049 Mount Zion Church Road, Alexis, North Carolina. I am President of Janice Hager Consulting.

Q. DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I caused to be pre-filed direct testimony supporting the allocation of Duke Energy Carolinas, LLC's ("DE Carolinas" or the "Company") electric operating revenues and expenses and original cost rate base assigned to the North Carolina retail jurisdiction and to each customer class according to the cost of service studies performed by the Company. I also submitted corrected direct testimony on behalf of the Company on February 14, 2020.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to rebut various points and issues raised by intervenors in this docket regarding:

1) Allocation of demand-related production costs in the Company's Cost of Service ("COS") studies. Specifically, I address Public Staff witness James McLawhorn's summary/exhibits of COS methodologies and recommendation of Summer/Winter Peak and Average ("SWPA") for allocation of demand-related production costs and Carolina Industrial Group for Fair Utility Group III ("CIGFUR") witness Nicholas Phillips'

recommendation of use of Winter Peak for allocation of demand-related production costs;

2) Allocation of distribution costs, specifically DE Carolinas' design and use of the minimum system study approach to allocate customer-related distribution system costs;

3) Allocation of uncollectible costs; and

4) Allocation of Grid Improvement Plan costs.

II. ALLOCATION OF DEMAND-RELATED PRODUCTION COSTS

Q. PUBLIC STAFF WITNESS JAMES MCLAWHORN DISCUSSES THE VARIOUS METHODOLOGIES FOR ALLOCATING DEMAND-RELATED PRODUCTION COSTS. PLEASE ADDRESS THOSE.

A. In response to the Commission's January 22, 2020 *Order Directing the Public Staff to File Testimony*, the Public Staff analyzed the differences between and among the various COS methodologies. The Public Staff analyzed the following methodologies:

SWPA – Summer/Winter Coincident Peak and Average Demand, which allocates a portion of the costs based on the average of the summer and winter peaks and a portion based on energy usage (expressed as average demand, the factor is total energy divided by the number of hours in the year)

SCP – Summer Coincident Peak

WCP – Winter Coincident Peak

SWCP – Summer/Winter Coincident Peak – an average of the summer and winter peaks

4CP – Four Coincident Peaks – an average of the four highest monthly peaks

12CP – Twelve Coincident Peaks – an average of the peaks for each month.

The analysis shows the methods dramatically shift the allocations between customer classes.[1] For example, moving from SCP to WCP to allocate demand-related production costs increases the allocation factor from 45.96% to 54.68% of the NC Retail allocation for Residential customers while reducing the allocation factor from 18.21% to 14.61% for OPT-G customers.

Q. WHICH DEMAND ALLOCATOR DID THE COMPANY USE TO ASSIGN DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS TO JURISDICTIONS AND CUSTOMER CLASSES IN THIS CASE?

A. Demand-related production and transmission costs are allocated using the Summer Coincident Peak (SCP) method.

Q. PLEASE SUMMARIZE THE CONCEPT OF ALLOCATING COSTS BASED ON COINCIDENT PEAK.

A. A coincident peak ("CP") allocator assigns the fixed demand-related production and all transmission-related costs to the jurisdictions and customer classes in

[1] DE Carolinas has reviewed Mr. McLawhorn's calculations. While the Company may have calculated them a little differently, his analysis is useful for making general observations about the various methods.

proportion to their respective contribution to the system's peak hourly demand during the Test Period. Each jurisdiction and customer class' cost responsibility (*i.e.*, the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. The cost of service study supporting the Company's proposed rate design in this proceeding allocates the fixed portion of production and transmission demand-related costs based upon a jurisdiction's and customer class' coincident peak responsibility occurring during the summer, otherwise known as the Summer Coincident Peak or SCP Allocator.

Q. WHY DO YOU SUPPORT THE USE OF THE SCP ALLOCATOR?

A. Some of the reasons I support the use of SCP by DE Carolinas are:

1. The application of the summer peak load to allocate demand-related production and transmission costs is consistent with the Single Coincident Peak Method identified in the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Costs Allocation Manual ("CAM")[2] with the recognition that an unusual situation was not addressed in the CAM. The unusual situation is the shifting from historically summer peak planning to winter peak planning, which I discuss below;
2. The predominance of the summer peak in DE Carolinas service

[2] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, January 1992.

territory. As I noted in my direct testimony, in 21 of the last 25 years the system peak occurred in the summer[3];

3. The historical significance of the summer peak in DE Carolinas' expansion planning such that the majority of DE Carolinas' embedded generation fleet was built in response to summer peaks, thus making it appropriate to allocate these historically incurred costs;
4. The benefit of a cost allocation methodology that encourages the shifting of usage to off-peak times;
5. The value of sending consistent pricing signals by using a method that has been approved by this Commission for many years; and
6. The importance of a consistent cost allocation methodology among DE Carolinas' jurisdictions so that the Company does not under- or over-recover its costs.

Q. WHICH METHODOLOGY DOES THE PUBLIC STAFF RECOMMEND?

A. Public Staff witness McLawhorn testifies that the Public Staff recommends the use of a summer/winter coincident peak and average demand (SWPA) methodology for allocation of demand-related production plant and plant-related costs based on the belief that SWPA "more accurately reflects generation planning and customer usage than does SCP."[4] Witness

[3] The 2019 peak was a summer peak as well; thus in 22 out of 26 years, the system peak has occurred in the summer.
[4] McLawhorn Direct Testimony, p. 6, lines 16-20.

McLawhorn states that "the SWPA methodology recognizes that some production plant costs are incurred primarily to provide sufficient capacity during peak periods, while other production costs are incurred because of the need to provide the lowest cost energy to customers during all hours."[5] He further states that an approach (such as SCP) "without an average component in the allocation factor … assumes that the Company's total production plant investment was made **only** to serve the peak load that occurs during one hour on a single day during the year."[6]

Q. DO YOU AGREE WITH HIS ASSESSMENT OF THE TWO METHODOLOGIES?

A. No. Witness McLawhorn's assertion that the SCP methodology only addresses the peak requirement of the capacity expansion planning process and places no value on the plants' requirement to produce energy at any time other than the peak hour is not the complete picture. Witness McLawhorn is focused on allocation of the demand-related production costs and ignores the energy-related costs, which the Company clearly takes into account when allocating production costs as described below. Looking at all production costs together provides the complete picture.

In developing a cost of service study, production costs are classified into demand and energy related costs. Plant capacity is considered fixed to meet demand and therefore, the cost of plant capacity was assigned to customers on

[5] McLawhorn Direct Testimony, p.10, line 18, - p. 11, line 1.
[6] McLawhorn Direct Testimony, p. 11, line 19, - p. 12, line 1 (emphasis in original).

the basis of their contribution to the summer coincident peak. Plant output in terms of kWh generation varies with the system energy requirements; therefore, all variable costs of production are assigned to customers based on their energy usage. In supporting the SWPA methodology, Public Staff witness McLawhorn fails to acknowledge that the cost of service study in this proceeding already classifies over $2 billion of production costs (fuel, purchased power, O&M, etc.) as variable, and allocates these costs to the jurisdiction and customer classes using an energy allocator.

Q. WHAT ABOUT THE PUBLIC STAFF'S ARGUMENT THAT SOME PORTION OF BASE LOAD PLANT SHOULD BE CLASSIFIED AS ENERGY-RELATED?

A. Witness McLawhorn correctly describes the integrated resource planning process, which looks at total costs in choosing the appropriate mix of generation resources. DE Carolinas' generation system includes a robust mix of baseload, intermediate, and peaking resources. Baseload plants have historically had higher capital costs and lower energy costs than peaking resources. This tradeoff is a key reason for integrated resource planning, which analyzes the total cost of resource mix options to choose the mix that produces the best overall least cost option. The resulting generation capital costs in rate base, which are being allocated for ratemaking purposes are a compilation of all the resources, almost all of which were placed into rate base prior to the shift to a winter emphasis in integrated resource planning in 2016. At the same time, the energy and energy-related production costs that are being allocated for ratemaking purposes in this case are tied to the generation mix that produces the energy.

Q. WHAT IS THE PRACTICAL IMPACT OF THE PUBLIC STAFF'S PROPOSED METHODOLOGY?

A. If adopted, the SWPA method would allocate approximately 61% of DE Carolinas' fixed demand costs using an energy allocator. This approach leads to a higher portion of the fixed costs being assigned to higher load factor customers. Advocates for this method feel this is equitable on the theory that high load factor customers benefit from the lower energy costs that result from the operation of base load plants as opposed to the higher energy costs of peaking plants. But proponents never carry this argument to its logical conclusion. That is, those customers allocated the higher capital costs based on energy usage, should be allocated the lower variable operating costs of those same base load facilities. If the primary theory behind the use of the SWPA allocation methodology is that fixed production plant costs are incurred to meet both capacity and energy requirements, then consideration should also be given to the variable operating costs. It seems only fair and equitable that high load factor customers should be allocated more of the lower variable energy costs, while low load factor customers should be allocated more of the higher variable energy costs.

The SWPA method allocates more of the demand-related production costs to higher load factor customers. Did higher load factor customers *cause* the Company to build base load plants and lower load factor customers *cause* peaking plants? I contend the answer to both questions is "no." All customers in aggregate "caused" the whole of the resource mix and should share equally in the costs based on their contribution to the recognized demand allocator, this is, peak demand.

If we think about electric vehicles, it is common sense that it is beneficial for customers to charge their vehicles at night when there is excess capacity available, and that customers should get a reduced rate when doing so because they are not driving any incremental capacity/demand-related costs on the system. However, the Public Staff's proposal that more than half of demand related costs should be allocated based on energy contradicts to this logic. Under the energy component of the Public Staff's proposal, an electric vehicle owner who charges in the middle of the night would be allocated the same amount of fixed plant costs as someone who uses the same amount of electricity in the middle of a hot summer afternoon. Intuitively, we know this is not right, which illustrates why the Public Staff's proposed SWPA method should be rejected. The allocation of DEMAND-related production costs based on DEMAND and ENERGY-related production costs based on ENERGY is the appropriate allocation methodology in my opinion.

Q. THE PUBLIC STAFF POINTS TO THE INTRODUCTION OF WINTER PEAK FOR INTEGRATED RESOURCE PLANNING PURPOSES. PLEASE ADDRESS.

A. Historically, Duke Energy Progress, LLC (formerly, Progress Energy, and prior to that Carolina Power & Light, "DE Progress") and DE Carolinas conducted their integrated resource planning by focusing on the summer peak demand and the resources needed to meet that load plus an adequate planning reserve margin. One factor that helped to ensure that meeting a summer peak ensured adequate resources for a winter peak is the fact that natural gas-fired resources historically had significantly greater potential MW output in the winter due to the colder, drier intake air. Therefore, even if the summer and winter peaks were close, planning focused on the need to meet the summer reserve margin. Over the past several years the difference between DE Carolinas' winter and summer peaks has greatly diminished and, beginning in 2016, DE Carolinas began focusing more on the winter-peak generation resource planning. A key driver for this change is the fact that the load and resource balance has changed drastically in the past few years, driven primarily by the high penetration of solar resources as well as the significant load response to recent cold weather. High levels of solar penetration do not contribute to DE Progress' or DE Carolinas' ability to meet winter peak load. Therefore in 2016, DE Progress' and DE Carolinas' integrated resource planning transitioned to winter capacity planning. By focusing on the winter peak load and the required winter reserve margin, Duke Energy can assure that summer peak loads are met as well. While winter peak planning will likely continue, both summer and winter peaks are important in the planning process. And, as noted earlier, the assets for which cost recovery is sought in this case are largely the result of an emphasis on summer peak planning.

Q. HAS THE PUBLIC STAFF INTRODUCED ANY NEW EVIDENCE IN THIS PROCEEDING TO JUSTIFY COMMISSION ADOPTION OF THE SWPA METHODOLOGY COMPARED TO PREVIOUS PUBLIC STAFF RECOMMENDATIONS?

A. Not in my opinion. Witness McLawhorn points to Commission orders in DE Progress and Dominion Energy North Carolina ("DENC") and concludes, "Thus, what the Commission has found in past rate cases for DEP and DENC holds true today for DEC – the appropriate cost-of-service methodology must consider overall energy consumption and peak demand."[7] In each of these cases, the Commission found that use of SWPA was most appropriate in each case based on the testimony and circumstances of *that particular case*; however, the Commission has also found the use of Summer CP to be appropriate based on the testimony and circumstances in other cases. Indeed, while witness McLawhorn references DE Progress rate cases from the 1980s, he fails to mention the Commission's more recent order on this issue for DE Progress. In the Commission's order in DE Progress's 2012 rate case (Docket No. E-2, Sub

[7] McLawhorn Direct Testimony, p. 22, lines 16-19.

1023), the Commission ruled that SCP was the most appropriate method for DE Progress, not SWPA, despite the Public Staff making many of the same arguments that they have made in this case. The Commission found and concluded, "that the summer coincident peak (1 CP) method is the most appropriate method for allocating costs between jurisdictions and between customer classes within the North Carolina retail jurisdiction for DEP in this proceeding. The Commission, having considered all of the evidence presented, finds that the 1 CP methodology is just and reasonable to all parties."[8]

As recently as February 2020, in the DENC Rate Case in Docket No. E-22, Sub 562, the Commission found and concluded "that cost allocation does not lend itself to a one size fits all approach, and the specific circumstances of each utility must be considered when determining the appropriate cost allocation methodology for that utility."[9] Here, as explained throughout my testimony, the circumstances specific to DE Carolinas demonstrate that SCP is the most appropriate allocation methodology for the Company.

I would also note that DE Carolinas has been consistent in its allocation of production costs for many years. The Company has not switched methodologies to maximize allocation to a specific jurisdiction from case to case. The Company has sought to have a consistent methodology between jurisdictions to the extent possible.

[8] *Order Granting General Rate Increase,* issued on May 31, 2013, in Docket No. E-2, Sub 1023, p. 14.
[9] *Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase,* issued on February 24, 2020, in Docket No. E-22, Sub 562, p. 72.

I continue to believe the Company's proposal to allocate demand-related production costs based on Summer CP is sound as explained in my direct and in this rebuttal testimony.

Q. CIGFUR WITNESS PHILLIPS RECOMMENDS USE OF THE WINTER PEAK FOR ALLOCATION OF DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No. First, given that the generation and transmission asset costs to be recovered in this proceeding were constructed based upon customers' contribution to the Summer CP, the proper response to this situation is to use the Summer CP in this case for cost of service and to focus on the converging summer and winter peaks in the rate design as has been done by Mr. Pirro.

Second, I have concerns with the volatility of the winter peak and the volatility that using a single winter peak could introduce into customer rates. Public Staff witness McLawhorn's testimony demonstrates this. He notes that the Company had forecasted the 2018 peak to be in the summer and 99 MWs higher than the winter peak but, instead, the winter peak was 1300 MWs higher than the summer peak that year.[10] This volatility in the single winter peak makes it less than optimal for use in cost allocation.

Third, even in the future, an appropriate allocation method would need to give some weight to the summer peak. For example, some of the demand

[10] McLawhorn Direct Testimony, p. 8, lines 9-13.

related production costs are costs of solar generation. This generation does not typically generate energy at the time of the winter peak, and so to allocate its costs based on a winter peak would be inappropriate. Also, the summer peaks continue to be strong in the DE Carolinas service territory. In the test year, three of the four highest monthly peaks occurred in the summer. In 2019, the highest peak during the year was in the summer, an important consideration for the utility.

I recommend that the Company continue to monitor the projected and actual monthly peaks and the key drivers for and the amount of investments in production plant in order to identify when and if a different allocation method should be proposed in future rate cases. The Company is open to looking at allocation methods that appropriately reflect the nature of its system demands and that also do not introduce excessive volatility into cost allocations and customer rates in future proceedings. Some of these methods the Company may evaluate in future rate cases may include the 4CP or 12CP allocation approaches also mentioned in the testimony of Witness McLawhorn. These methods continue to give some weight to the summer months, are less volatile than the WCP method, and do not allocate demand costs based on an energy allocator. As witness McLawhorn noted, the 12CP method has historically been utilized by the Federal Energy Regulatory Commission for its COS purposes. The 4CP method is a common alternative. While the appropriate method will depend on the unique characteristics of a specific utility's load, these are two methods that the Company could evaluate as its demand profile changes.

III. MINIMUM SYSTEM STUDY

Q. WHAT ISSUES ARE RAISED BY INTERVENORS REGARDING USE OF A MINIMUM SYSTEM STUDY TO ALLOCATE A PORTION OF DE CAROLINAS' DISTRIBUTION COSTS TO CUSTOMERS?

A. North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy ("NCJC, et al.") is the only party objecting to the Company's use of the Minimum System Concept in allocating distribution costs. NCJC, et al. witness Jonathan Wallach testified that the Commission should direct the Company to discontinue use of the minimum system method for classifying distribution costs for cost of service purposes.[11] CIGFUR witness Phillips, agreed with the Company's use of the minimum system method.[12]

Q. WHAT IS THE THEORY BEHIND MINIMUM SYSTEM?

A. The theory behind the use of a minimum system study is sound and consistent with cost causation which is the bedrock of COS studies. DE Carolinas' Minimum System Study allowed DE Carolinas to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels). Every customer requires some minimum amount of wires,

[11] Wallach Direct Testimony, p. 3, lines 18-20.
[12] Phillips Direct Testimony, p. 14, lines 1-10.

poles, transformers, etc. to receive service; therefore, every customer "caused" DE Carolinas to install some amount of such distribution assets.[13] The concept DE Carolinas used to develop its minimum system study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb). This methodology allows the utility to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, regardless of the customer's frequency of use. Without the minimum system, low use customers could avoid paying for the infrastructure necessary to provide service to them which is counter to cost causation principles. Once minimum system costs have been identified, all distribution costs over the minimum system costs are determined to be driven by demand.

Q. WHAT ARE WITNESS WALLACH'S SPECIFIC OBJECTIONS TO THE MINIMUM SYSTEM METHOD, AND WHAT IS YOUR RESPONSE TO THOSE OBJECTIONS?

A. Witness Wallach urges the Commission to reject the Company's proposed allocations used in justifying its base revenue increase. His recommendation is based on his conclusion that the Company's cost of service allocates too much cost to residential customers because it has relied on the concept of minimum

[13] On page 13 and 14 of his testimony, Mr. Wallach offers an example of an apartment building and a large commercial load as illustrative examples of the unfairness of the minimum system concept. Allocation of costs and rate designs are based on creating large "buckets" of costs and large groups of similarly situated customers. Naturally, within each bucket, the cost of serving an individual customer will be, in some cases, greater than the costs allocated to the customer and, in other cases, less than the costs allocated to the customers. This fact does not make the methodology unfair.

system and because of how the Company has allocated the remaining distribution costs based on non-coincident peak.[14] He urges the Commission to "give no weight" to the Public Staff's endorsement of minimum system classification method.[15] Mr. Wallach believes that Public Staff's recommendations are based on the "unsubstantiated belief that there is a minimum portion of the cost of the distribution grid which is incurred regardless of load."[16]

I disagree that the Public Staff's belief is "unsubstantiated." On the contrary, the NARUC CAM substantiates the concept.

Q. WHAT DOES THE NARUC CAM SAY ABOUT ALLOCATION OF DISTRIBUTION COSTS TO CUSTOMERS?

A. The NARUC CAM specifically states in the section on allocation of embedded costs that "the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system"[17] The Public Staff recognizes that the NARUC CAM "continues to be considered an important resource for the calculation and allocation of electric utility cost of service for regulatory commissions, consumer advocates, and parties before the

[14] Wallach Direct Testimony, p.3, lines 10-17.
[15] Wallach Direct Testimony, p. 49.
[16] Wallach Direct Testimony, p. 42, lines 14-17.
[17] NARUC CAM, p. 90. It is only in the marginal cost allocation section that the basic customer method is included in the NARUC CAM. Most utilities, including DE Carolinas, have traditionally allocated costs using an embedded cost, as opposed to a marginal cost, methodology. The major problem with allocating costs based on marginal costs is that marginal-cost based rates will only "by rare coincidence" yield allowed revenue requirements, thus requiring some form of reconciliation. (NARUC CAM, page 14.) No party in this proceeding (even NCJC, et al. as far as I can tell) is advocating moving from an embedded cost of service to a marginal cost of service.

Commission testifying on issues of cost-of-service and rate design."[18] The Manual suggests two methods of allocating embedded distribution costs, both of which would identify a portion of FERC distribution asset accounts 364 to 368 as customer-related and a portion as demand-related. Therefore, Mr. Wallach's proposal suggesting the Company adopt the basic customer method and all of accounts 364-368 should be allocated based on demand, with none allocated to the customer component, is inconsistent with the NARUC CAM.[19]

Q. IN ADDITION TO THE NARUC CAM, WHAT ARE OTHER REASONS THAT THE USE OF A MINIMUM SYSTEM STUDY IS APPROPRIATE TO ALLOCATE A PORTION OF THE DISTRIBUTION COSTS?

A. The three utilities in North Carolina have a long history of using minimum system studies to identify the portion of distribution costs that are customer-related. In addition, as I noted in my Direct Testimony, in its Report on the Minimum System Methodology in NCUC Docket No. E-100, Sub 162, the Public Staff concluded that the use of the Minimum System Method for classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic facilities charge.[20] The Public Staff agrees with the Company that distribution related costs have both demand-related and fixed characteristics. The Public Staff concludes that

[18] Ibid, p. 4.

[19] Wallach Direct Testimony, p.17, lines 21-22. While Mr. Wallach calls the Basic Customer Method "a best practice" on page 15 of his testimony, his only citation is to a very recently published work by the Regulatory Assistance Project.

[20] Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, March 28, 2019, Docket No. E-100, Sub 162, p 16-17.

"[w]hile distribution related costs must be sized to meet some level of maximum demand, there is also a minimum cost for the distribution system that must be incurred regardless of demand."[21] (Emphasis in original.)

The Public Staff also has several observations regarding setting the Basic Facilities Charge. For example, the Public Staff differentiates between the considerations in a COS study and Rate Design, the latter of which the Public Staff states should take additional things in consideration such as policy objectives and appropriate price signals. Similar to Public Staff, I believe it is appropriate to keep a COS study free of biases and focus on cost causation.

Q. WHAT DOES MR. WALLACH SAY ABOUT THE COST THAT A NO-LOAD CUSTOMER WOULD IMPOSE ON THE SYSTEM?

A. Mr. Wallach offers that the "true cost per customer is zero since distribution equipment that carries zero load can serve an infinite number of customers with zero load."[22] I would first note that the minimum system methodology is based on a small load, not zero load. However, his example serves to make my point as well. Suppose the Company had built a distribution system for customers who subsequently stopped placing any load on the system. If costs have been allocated and rates designed to recover costs on volumetric or demand rates then there is no opportunity for the Company to recover these costs.

[21] Ibid, p. 8.

[22] Mr. Wallach includes a footnote on page 11 of his testimony which says, "In fact, it is unlikely that DEC would incur the cost to connect a zero-load customer under the Company's line extension policies and would instead require the zero-load customer to bear any such connection costs." He then references the Company's Line Extension Plan. However, there is no mention of connection of a zero load customer in the Company's Line Extension Plan, probably because it is such a ludicrous scenario.

Distribution equipment with "zero load" that was installed to ensure a customer could receive electricity still has a cost that must be borne by someone under utility ratemaking principles. If these costs are recovered using a demand allocator instead of minimum system study, customers with higher usage are subsidizing those with lower usage. Under the minimum system concept, all customers are appropriately allocated costs for equipment that stands ready to provide their electrical needs.

In reality, a customer that has no demand for electricity would have no need to be connected to the distribution system." Frankly, a customer who does not intend to use any electricity wouldn't be a customer and wouldn't be billed at all. But if someone, for whatever reason, wants electricity to light a single 100-Watt light bulb, that customer will require distribution assets such as poles and conductors and transformers to deliver that electricity.

Q. HOW DOES WITNESS WALLACH ATTEMPT TO JUSTIFY HIS OPPOSITION TO THE ALLOCATION OF MINIMUM SYSTEM COSTS TO THE CUSTOMER CLASS?

A. Witness Wallach contends that customer connection costs are "generally limited to plant and maintenance costs for a service drop and meter, along with meter reading, billing, and other customer-service expenses.[23] His next sentence quotes Bonbright's *Principles of Public Utility Rates* to support his argument noting that the text says that metering and billing expenses are "the most

[23] Wallach Direct Testimony, p. 28, p. 17-19.

obvious examples" of customer costs.[24] He fails to mention that the quoted text does not say these are the only costs.

While it is true that Dr. Bonbright recognizes the difficulty of determining the proper allocation for the minimum system costs, he concludes that the exclusion of minimum system costs from demand-related costs is on "much firmer ground" than its exclusion from customer costs.[25] Ultimately, however, he recognizes that utilities must distribute all costs among the classes of customers in a fully-distributed cost analysis.[26] But, even more important, is the NARUC CAM that was developed after Dr. Bonbright's work. The CAM, developed by a large group of mostly state utility commission and FERC staff members (including North Carolina representatives Dennis Knightingale and Ben Turner), moved from the theoretical world of Dr. Bonbright to the reality of utilities' needs to move from development of revenue requirements to rate structures. The full allocation of all costs is a critical step in the cost of service study process. As I noted in earlier in this testimony, the CAM states that a portion of the distribution costs ARE customer-related.

[24] James C. Bonbright, *Principles of Public Utility Rates.* Columbia University Press (1961 edition), p. 311.
[25] Bonbright, pp. 348.
[26] Bonbright, pp. 348-349. "Fully distributed cost analysis" is a synonym for cost analyses based on embedded instead of marginal costs.

IV. ALLOCATION OF UNCOLLECTIBLE COSTS

Q. IS IT APPROPRIATE TO INCLUDE UNCOLLECTIBLE COSTS IN THE CUSTOMER CLASSIFICATION FOR INCLUSION IN THE BASIC FACILITIES CHARGE?

A. Yes. Witness Wallach makes an unsupported claim that these costs "tend to vary with revenues and thus with usage."[27] DE Carolinas has historically treated these as a customer cost in the same category as other FERC Customer Accounting Accounts. This is a reasonable assumption.

V. ALLOCATION OF GRID IMPROVEMENT PLAN INVESTMENTS

Q. THE PUBLIC STAFF RECOMMENDS THAT THE COMMISSION DIRECT DE CAROLINAS TO STUDY THE ALLOCATION OF GRID IMPROVEMENT PLAN INVESTMENTS BASED ON THE ALLOCATION OF THE REALIZED BENEFITS OF THOSE INVESTMENTS AND REPORT ITS FINDINGS IN THE NEXT RATE CASE.[28] HOW DO YOU RESPOND?

A. The Company has proposed allowing the investments associated with the Grid Improvement Plan to follow the same cost causation principles that are applied to the investments in the same FERC accounts as reflected in the COS Study. While I have not looked at these costs in particular, it is my opinion that attempting to allocate ANY investment costs for ratemaking purposes based on perceived benefits realized by customers, as differentiated from cost causation

[27] Wallach Direct Testimony, p. 30.
[28] Public Staff Witness Thomas Direct Testimony, p. 52.

to the utility, is likely to be very subjective and thus controversial. One need look no further than Mr. Thomas' own testimony which analyzes the customer benefits discussed by DE Carolinas witness Oliver to see there are differing opinions on how to quantify customer benefits.

VI. CONCLUSION

Q. IN CONCLUSION, DO YOU CONTINUE TO BELIEVE THE METHODOLOGIES USED BY DE CAROLINAS IN CONDUCTING ITS COST OF SERVICE STUDY FOR THIS CASE ARE APPROPRIATE AND REASONABLE?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

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

A. My name is Janice Hager, and my business address is 2049 Mount Zion Church Road, Alexis, North Carolina. I am President of Janice Hager Consulting.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I caused to be pre-filed direct testimony supporting the allocation of Duke Energy Carolinas, LLC's ("DE Carolinas" or the "Company") electric operating revenues and expenses and original cost rate base assigned to the North Carolina retail jurisdiction and to each customer class according to the cost of service studies performed by the Company. On February 14, 2020, I submitted corrected direct testimony on behalf of the Company. I also submitted rebuttal testimony on behalf of DE Carolinas on March 4, 2020.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the cost allocation implications of Public Staff witness Dustin Metz's supplemental testimony recommending that the capital costs of the Clemson University Combined Heat and Power ("Clemson CHP") project be removed from the Company's rate base.

Q. PUBLIC STAFF WITNESS METZ MAKES THE ARGUMENT THAT THE COSTS OF THE CLEMSON CHP SHOULD NOT BE ALLOCATED TO NORTH CAROLINA RETAIL CUSTOMERS, IN PART, BECAUSE THE ELECTRICITY MAY NEVER REACH DE CAROLINAS' TRANSMISSION SYSTEM. IS HIS ARGUMENT CONSISTENT WITH SOUND COST ALLOCATION PRINCIPLES?

A. No. If a generation resource is available to serve system load requirements, it is a system asset and is generally allocated to all jurisdictions across the system, regardless of where it is physically located. For example, DE Carolinas has solar generation assets that are installed on the rooftops of North Carolina customers under the Company's Solar Photovoltaic Distributed Generation Program. The electricity from these resources may also never reach DE Carolinas' transmission system. However, the costs of these resources, up to the avoided cost, are allocated to both North Carolina and South Carolina customers in the cost of service study. Similarly, DE Carolinas purchases power from distribution connected qualifying facilities. Again, the electricity purchased under these purchased power agreements may never reach the Company's transmission system, yet the costs are allocated to both North Carolina and South Carolina customers in the cost of service study. The Clemson CHP facility is no different than these examples and should be allocated to both North Carolina and South Carolina customers.

Q. DO YOU HAVE ANY ADDITIONAL THOUGHTS, FROM A COST OF SERVICE PERSPECTIVE, AS TO WITNESS METZ'S RECOMMENDATION TO REMOVE THE COSTS OF THE CLEMSON CHP PROJECT?

A. Yes. In addition to being inconsistent with sound cost allocation principles, I believe the recommendation in Mr. Metz's supplemental testimony is one-sided. If you remove the generation resource from rate base, it would only be fair and equitable to remove an equivalent amount of load from South Carolina Retail load. Doing so will cause the Production Demand allocator to increase for North Carolina, thereby allocating more demand-related costs to North Carolina Retail and increasing the revenue required from North Carolina customers. Witness Metz has not incorporated this impact in his adjustment.

Q. DOES THIS CONCLUDE YOUR PRE-FILED SUPPLEMENTAL REBUTTAL TESTIMONY?

A. Yes.

MS. JAGANNATHAN: Thank you. And I would also move that Ms. Hager's testimony summary and errata page be entered into the record as if given orally.

CHAIR MITCHELL: Hearing no objection, that motion is allowed as well.

(Whereupon, the prefiled testimony summary and errata of Janice Hager were copied into the record as if given orally from the stand.)

I am the Cost of Service witness for Duke Energy Carolinas. Utilities use Cost of Service Studies to spread to customer classes the revenue requirements identified by the Company for recovery. Using the principle of cost causation, revenues, expenses, and rate base costs are assigned to the specific jurisdictions and customers classes that "caused" such costs to be incurred.

Parties in this case are not challenging many of the cost allocation methods proposed by the Company. While the Public Staff initially opposed Duke Energy Carolinas' proposal to use the Summer Coincident Peak (SCP) method to allocate production and transmission demand-related costs, this issue has since been resolved by the Second Partial Settlement between the parties. The North Carolina Justice Center group of intervenors (NCJC, et al.) is challenging the Company's continued use of the minimum system method of allocating some distribution costs.

Duke Energy Carolinas has used the summer coincident peak demand to allocate production and transmission demand-related costs for as long as anyone can remember. I continue to believe that SCP is the most appropriate methodology for Duke Energy Carolinas for a number of reasons, including: the predominance of the summer peak in the Company's service territory, the historical significance of the summer peak in Duke Energy Carolinas' planning process, the fact that the majority of the Company's embedded generation fleet was built in response to summer peaks, and the benefit of a cost allocation methodology that encourages the shifting of usage to off-peak times. In its Second Partial Settlement with the Company, the Public Staff has agreed, for purposes of settlement, that the Company may use the SCP methodology in this case.

As I explain in my rebuttal testimony, all customers in aggregate "caused" the whole of the resource mix and should share equally in the costs based on their contribution to the recognized demand allocator, that is, peak demand. CIGFUR agrees that it is appropriate for the Company to use a coincident peak methodology, but proposes that the Company switch to a Winter Peak demand allocator. While it is true that the Company has shifted to winter planning, as I alluded to earlier, the assets included for cost recovery in this case were incurred based on summer peak planning. The Company is open to looking at other allocation methods in the future, looking for methods that would appropriately reflect the nature of system demands and that also do not introduce excessive volatility into cost allocations and customer rates in future proceedings. For instance, in its Settlement Agreement with CIGFUR, the Company has agreed to consider and file the results of a class cost of service study using the Summer/Winter Coincident Peak method in its next general rate case, and in its Second Partial Settlement with the Public Staff, the Company has agreed to analyze and develop cost of service studies under at least six different methodologies.

NCJC, et al. witness Jonathan Wallach testified that the Commission should direct the Company to discontinue use of the Minimum System Method for classifying distribution costs for cost of service purposes. The concept of minimum system is that some minimum amount of assets classified as distribution assets are in place in order to be available to serve customers, regardless of customer demand. Therefore, distribution asset costs should be allocated partly on the basis of the number of customers and partly based on the demand of those customers. In its report on Minimum System ordered by this Commission after Duke Energy Carolinas' last general rate case, the Public Staff concluded that the use of the Minimum System Method for classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic facilities charge.

In conclusion, I continue to believe the methodology used by Duke Energy Carolinas in conducting its Cost of Service Study for this case is appropriate and reasonable.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1214

In the Matter of: Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	))))))))	**DUKE ENERGY CAROLINAS, LLC'S CORRECTIONS TO REBUTTAL TESTIMONY OF JANICE HAGER**

CORRECTIONS TO REBUTTAL TESTIMONY OF JANICE HAGER

PAGE 19, FOOTNOTE 18 SHOULD READ:	REASON FOR CHANGE:
~~Ibid, p. 4.~~ Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, March 28, 2019, Docket No. E-100, Sub 162, p. 4.	Replaced "Ibid." with full citation since reference to this source had not yet been made.
PAGE 20, FOOTNOTE 22 SHOULD READ:	REASON FOR CHANGE:
Wallach Direct, p. 31, lines 23-25. Mr. Wallach includes a footnote on page 11 of his testimony which says, "In fact, it is unlikely that DEC would incur the cost to connect a zero-load customer under the Company's line extension policies and would instead require the zero-load customer to bear any such connection costs." He then references the Company's Line Extension Plan. However, there is no mention of connection of a zero load customer in the Company's Line Extension Plan, probably because it is such a ludicrous scenario.	Inadvertently omitted the reference to "Wallach Direct, p. 31, lines 23-25" at the beginning of the footnote.

MS. JAGANNATHAN: Thank you.

Q. And now I'll turn to you, Mr. Pirro.

Would you please state your name and business address for the record?

CHAIR MITCHELL: Mr. Pirro, you are on mute.

THE WITNESS: (Michael J. Pirro) Michael J. Pirro, 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy Carolina, capacity is director of southeast pricing and regulatory solutions.

Q. And on September 30, 2019, did you cause to be prefiled in this docket, direct testimony consisting of 25 pages as well as 9 exhibits to that testimony?

A. Yes, that is correct.

Q. Did you also cause to be filed, corrected direct testimony consisting of 25 pages on October 23, 2019?

A. Yes.

Q. On February 14, 2020, did you cause to be prefiled in this docket, supplemental direct testimony consisting of four pages?

A. Yes, that is correct.

Q. And did you cause to be prefiled in this docket, rebuttal testimony consisting of 13 pages on March 4, 2020?

A. Yes.

Q. Did you cause -- did you cause to be prefiled in this docket, second supplemental direct testimony consisting of three pages on July 2, 2020?

A. Yes, I did.

Q. And finally, on August 21, 2020, did you cause to be prefiled in this docket, second settlement testimony consisting of four pages, as well as Pirro Second Settlement Exhibit 4 and Pirro Second Settlement Exhibit 9?

A. Yes, I did.

Q. Do you have any changes or corrections to your prefiled corrected direct testimony, supplemental direct testimony, rebuttal testimony, second supplemental direct testimony, or second settlement testimony?

A. No, I do not.

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

A. Yes, they would.

Q. And do you have any changes or corrections to any of the exhibits to your prefiled testimony?

A. I do not.

Q. Thank you.

MS. JAGANNATHAN: Chair Mitchell, at this time, I would move that Mr. Pirro's prefiled corrected direct testimony, supplemental direct testimony, rebuttal testimony, second supplemental direct testimony, and second settlement testimony be entered into the record as if given orally from the stand.

CHAIR MITCHELL: Hearing no objection, the motion is allowed.

(Whereupon, the prefiled corrected direct, supplemental direct, rebuttal, second supplemental direct, and second settlement testimony of Michael J. Pirro were copied into the record as if given orally from the stand.)

I. INTRODUCTION AND PURPOSE

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202. I am Director, Southeast Pricing & Regulatory Solutions for Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company"), Duke Energy Progress, LLC ("DE Progress"), and Duke Energy Florida, LLC ("DE Florida").

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR, SOUTHEAST PRICING & REGULATORY SOLUTIONS?

A. My primary responsibility is to provide rate analysis, tariff administration and to develop the rates and charges contained in tariffs and electric service contracts for Duke Energy Corporation's ("Duke Energy") Southeast utility operating companies, including DE Carolinas.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I received a Bachelor of Science degree in Business Administration from LeMoyne College in 1989. In August 1989, I began work for Niagara Mohawk in Syracuse, New York in its Rates & Regulatory Department as a Senior Analyst responsible for the Company's operating revenue forecast. In 1996, I accepted a position as Senior Special Contract Analyst for Niagara Mohawk. In 1999, I joined Niagara Mohawk's Customer Accounting organization where I held the position of Manager, Complex Billing. In 2005, I joined the Collections organization as a

Principal Collection Specialist. In 2008, I joined the Operations Department as Principal Settlement Analyst responsible for New York Independent System Operator settlement. In 2013, I left Niagara Mohawk and accepted a position in the Customer Care section of Pacific Gas and Electric's ("PG&E") General Rate Case core team. I began my employment with Duke Energy in 2016 where I assumed my current position.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR OTHER STATE UTILITY REGULATORY COMMISSIONS?

A. Yes. I testified before the North Carolina Utilities Commission (the "Commission") in DE Carolinas' last general rate case proceeding in Docket No. E-7, Sub 1146. I also testified before the South Carolina Public Service Commission in DE Carolinas' last general rate case proceeding in Docket No. 2018-319-E.

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

A. My testimony demonstrates that the rates DE Carolinas proposes reflect appropriate rate making principles, and result in an equitable basis for recovery of the Company's revenue requirements across and within its various customer classes and rate schedules. My testimony: (1) describes the changes to the Company's retail electric rate schedules; (2) quantifies the effect of these proposed changes on the Company's North Carolina retail electric customers; (3) discusses how DE Carolinas proposes to implement the tariffs approved by the Commission in this proceeding; and (4) describes other requested changes to the Company's tariffs and service regulations.

Q. PLEASE DESCRIBE THE EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. The exhibits to my testimony are as follows:

- Pirro Exhibit 1 consists of the North Carolina Retail Electric Rate Schedules and Service Regulations that DE Carolinas proposes to be effective for service rendered on and after October 30, 2019. In the event the Commission suspends rates in this proceeding, the Company requests rates to be effective no later than August 1, 2020. This exhibit is the same as Exhibit B to the Company's Application in this docket.
- Pirro Exhibit 2 sets forth the North Carolina retail rate design revenues under the Company's present and proposed rate schedules, including the effects of the proposed Excess Deferred Income Tax Rider ("EDIT-2 Rider") and migration adjustments.
- Pirro Exhibit 3 shows bill comparisons between the Company's present and proposed rates.
- Pirro Exhibit 4 provides a comparison of rate of return by rate class.
- Pirro Exhibit 5 provides a historical comparison of return on rate base by rate class.
- Pirro Exhibit 6 provides a statement regarding the probable effect of the proposed rates on peak demand and sales. This exhibit is the same as Exhibit D to the Company's Application.
- Pirro Exhibit 7 illustrates the revenue class impacts from the proposed increase, and reflects the revenue class impacts contained in the Company's Application.

- Pirro Exhibit 8 illustrates the Basic Facilities Charges for the major customer classes.
- Pirro Exhibit 9 provides the derivation of the Company's proposed Excess Deferred Income Tax Rider ("EDIT-2 Rider") that describes rate credits associated with changes in federal and North Carolina corporate income tax rates.

Q. WERE PIRRO EXHIBITS 1 THROUGH 9 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes. They were.

II. <u>SUPPORT OF PRO FORMA ADJUSTMENTS</u>

Q. DID YOU PROVIDE ANY DATA USED IN CONNECTION WITH THE PRO FORMA ADJUSTMENTS MADE TO THE TEST PERIOD IN THIS PROCEEDING?

A. Yes. I provided the retail sales and number of customers to Witness McManeus for use in calculating the pro forma adjustment to growth in customers in this proceeding.

Q. HOW DID THE COMPANY DETERMINE THE NUMBER OF CUSTOMERS SERVED AND THE ATTENDANT ANNUALIZED SALES AT THE END OF THE TEST PERIOD?

A. The "Test Period" for this proceeding is from January 1, 2018 through December 31, 2018. To arrive at the appropriate number of customers served and the attendant annualized sales levels at the end of the Test Period, the Company used a combination of regression analysis and a customer-by-customer approach. For the

Residential class, General Service Schedule BC, and Lighting class, the Company used regression analysis. Attendant annualized sales were calculated by applying the projected number of additional customers served at the end of the Test Period to weather-normalized kWh consumption per customer.

For the remaining General Service schedules and Industrial class, where large customers entering and leaving the system have non-negligible impacts on growth, the Company used the customer-by-customer approach to determine the number of customers. Under the customer-by-customer approach, each customer is individually analyzed during the Test Period to determine its status as a new or lost customer. Customers that were present the entire twelve-month Test Period were excluded from the analysis. For new customers, those months during the Test Period prior to the new service receive a pro forma adjustment to reflect energy sales that would have occurred during the period based upon that individual customer's usage characteristics. Similarly, customers that are lost during the Test Period have their respective sales removed from the Test Period. Again, this adjustment is made based on the specific characteristics of the individual customer. In both cases, the adjustment provides a meaningful determination of the sales gained or lost during the Test Period.

Q. HOW DID THE COMPANY DETERMINE THE NUMBER OF CUSTOMERS SERVED AND THE ATTENDANT ANNUALIZED SALES AT THE END OF THE EXTENDED PERIOD?

A. The "Extended Period" for this proceeding is from January 1, 2019 through January 31, 2020. Projected numbers of Residential class, General Service Schedule BC, and Lighting class customers served at the end of the Extended Period were derived by updating the Test Period regression analysis to include additional data from the Extended Period. The attendant annualized sales were recalculated using the new projected number of customers and further adjusted for changes observed in customer usage during the extended period.

The Extended Period customer-by-customer approach for the remaining General Service schedules and Industrial class is executed similarly to the Test Period customer-by-customer approach. Each customer is individually analyzed during the Extended Period to determine its status as a new or lost customer. For new customers, all available usage data in the Extended Period is used to estimate a full year of usage data to be added. For customers that are lost during the test period, all associated usage during the Test Period is removed.

Q. DID YOU PROVIDE ANY OTHER ADJUSTMENTS?

A. Yes. I provided annualized retail revenues based on present rates.

Q. ARE YOU SPONSORING A PRO FORMA ADJUSTMENT BASED UPON THE REQUESTED RATES APPLICABLE FOR MISCELLANEOUS REVENUES?

A. Yes. Based on the proposed rates contained primarily in the Service Regulations, a pro forma adjustment reducing miscellaneous revenues by $7,837,811 should be included in cost of service. A discussion of the changes in these rates is addressed later in my testimony.

III. RETAIL ELECTRIC RATE SCHEDULES AND RIDERS

A. Rate Design Approach

Q. HOW DID YOU DESIGN THE VARIOUS RATE SCHEDULES IN THIS CASE?

A. I used the cost of service information prepared by the Company and supported by Witness Janice Hager as a major component for the rate design. As Witness Hager describes in her testimony, the cost of service study allocates costs to the jurisdictions and various rate classes and separates the customer, demand, and energy components of cost. I also reviewed and considered the rates of return across the customer classes derived from the cost of service study. Additionally, I reviewed the Company's load research data to examine customers' usage characteristics and to determine relationships between energy and demand, both on a coincident peak and non-coincident peak basis that might prove pertinent to the design of the Company's rates. I used marginal cost information to assess the merits of seasonal and time-of-use pricing relationships that are appropriate to be considered in the final rate design. Marginal cost data supports a reduced emphasis to on-peak energy rates as the difference between on-peak and off-peak marginal energy cost has narrowed over the past years. It also no longer supports a substantial emphasis on summer pricing. As noted in the Company's Integrated Resource Plan, recent data indicates winter peak demand should also be considered in resource planning and consequentially should be a consideration when designing rates.

Q. PLEASE ELABORATE ON HOW YOU DEVELOPED THE PROPOSED RATES.

A. First, each rate class's target total proposed change in revenue requirement was determined. Then, the rate schedules within each rate class were designed to sum to the total proposed change in revenue target for that respective rate class.

Q. WHAT DID YOU CONSIDER BESIDES THE REVENUE REQUIREMENT IN THE DESIGN PROCESS?

A. In addition to the revenue requirement, consideration was given to current rates and their structure, impacts upon customers, equitable pricing structures, simplicity of the rate design, administrative complexity, and rate and revenue stability when establishing DE Carolinas' proposed rates. There are three basic cost categories: customer cost, demand cost, and energy cost. Efficient rate design considers and reflects the component costs within each category. While the unit cost study justifies an increase to the monthly Basic Facilities Charge to better reflect customer-related costs and minimize customer cross-subsidization, the Company is not proposing to raise the Basic Facilities Charge in this proceeding for reasons discussed later in my testimony.

Q. WHAT ARE DE CAROLINAS' RATE DESIGN OBJECTIVES FOR THE RATES PROPOSED IN THIS PROCEEDING?

A. As discussed by Witness Stephen De May, the Company is requesting a rate increase to recover its costs of providing safe and reliable electric service and to maintain a strong financial position as it remains in a period requiring major capital expenditures. In doing so, the Company aims to better reflect the cost to serve customers within its residential, general, industrial, and lighting rate schedules.

Q. WHAT ARE THE COMPANY'S SERVICE CLASSIFICATIONS AND MAJOR RETAIL ELECTRIC RATE SCHEDULES?

A. The Company's retail customers are separated into four major service classifications: Residential, Small and Large General Service, Industrial, and Lighting. The Company's major retail electric rate schedules include: Rates RS and RE – Residential Service; Rate SGS – Small General Service; Rate LGS – Large General Service; Rate I – Industrial Service; Rate OPT-V – Optional Power Service; Rate OL – Outdoor Lighting Service; and Rate PL – Street and Public Lighting Service. Together, these rate schedules comprise a substantial portion of the Company's retail electric revenue requirement.

Q. PLEASE EXPLAIN HOW THE REVENUES PRODUCED UNDER CURRENT RATES COMPARE TO THE REVENUES THAT WOULD BE PRODUCED BY THE PROPOSED RATES.

A. As required by Commission Rule R1-17(b)(9), Pirro Exhibit 2 sets forth a comparison of the revenue produced by the present schedules during the Test Period with the revenue that would be produced under the proposed schedules. For comparison, both the present and proposed revenues reflect the base fuel and fuel-related costs component discussed by Witness Kim McGee in her testimony. The revenues produced by the schedules shown in Columns (a) and (b) were calculated using the North Carolina retail sales for the Test Period. Column (c) shows the amount of additional revenue produced by the proposed rates. The percentage increase for each rate schedule exclusive of riders is shown in Column (d). Column (m) shows the percentage increase for each rate schedule with riders inclusive of EDIT-2. The revenues shown in Exhibit 2 eliminate Rate HP, Hourly Pricing, due to the differences of marginal cost versus embedded cost rate making. Historically, any additional revenues allocated to this rate were borne by the respective baseline rates through rate design; the cost of service treatment formalizes this approach.

Q. HOW DO YOU PROPOSE TO ALLOCATE THE REVENUE INCREASE AMONG THE RATE CLASSES?

A. The base rate increase has been allocated to the rate classes on the basis of rate base. This allocation methodology distributes the increase equitably to the classes while gradually moving each class's deficiency or surplus contribution to return to the retail average rate of return, within a band of reasonableness of +/- 10 percent, if possible.

Q. DID THE COMPANY CONSIDER THE RESULTS OF A UNIT COST STUDY IN DESIGNING THE PROPOSED RATES?

A. Yes. The unit cost study from the cost of service study provides customer, demand, and energy related unit costs that are important in establishing cost-based rates. Setting rates that are aligned with unit cost minimizes cross-subsidization within a rate class and provides appropriate price signals to customers regarding the true cost impact of their usage. The unit cost study also indicates it is appropriate to raise the monthly Basic Facilities Charge to better reflect all customer-related costs. To do otherwise results in customer cross-subsidization. Therefore, the Company would normally propose the Basic Facilities Charge for all rate classes be set to recover approximately 50 percent of the difference between the current rate and the full customer-related unit cost incurred to serve these customer groups. This approach would be taken because current rates significantly understate the current unit cost of service related to the customer component of cost. This recommendation reduces subsidization while moderating the rate impact on low usage customers. However, the Company has decided, in this rate proceeding, not to increase the Basic Facilities Charges and to leave the Basic Facilities Charges at current rates due to past concerns raised by low income and other advocates with respect to the level of the charge. Instead of requesting an increase to that charge in this proceeding, the Company has instead requested that a collaborative stakeholder process be formed to discuss opportunities to address low income, fixed income and low usage customer concerns. Once the Company has the benefit of that collaborative process, the Basic Facilities Charges will be addressed in future proceedings to properly reflect equitable cost-based rates that provide accurate price signals to our customers.

Q. WHAT OTHER CONSIDERATIONS IMPACT DE CAROLINAS RATE DESIGN?

A. When moving rate schedules and riders closer to a more cost-justified basis, it is important to consider the impact upon customers and to employ the principle of "gradualism." This principle was applied in this proceeding to update price relationships and levelized the percentage change in revenues on participants within the rate class while still moving towards a more equitable pricing structure. This approach also minimizes rate migration concerns as the pricing reflected in each rate schedule moves gradually towards the requested rate class rate of return. In most cases, the percent change in rates for all schedules within the rate class was increased by the same percentage.

Q. IS THE COMPANY PROPOSING ANY NEW PEAK TIME PRICING RATE DESIGNS OFFERING REAL TIME PRICE SIGNALS IN THIS PROCEEDING?

A. No, not at this time. However, the Company will be implementing nine new dynamic pricing pilots effective October 1, 2019 in compliance with the Commission's order in Docket No. E-7, Sub 1146 (the "2017 Rate Case"). DE Carolinas continues to review and analyze rate designs that offer customers opportunities to respond to price signals to achieve a lower cost for electric service. The Company is upgrading its billing system infrastructure to better support these types of designs. Smart Meters, installed for the majority of current customers, will provide the interval level data that is required to develop and bill these innovative designs. DE Carolinas is near completion of deploying Smart Meters that offer this level of meter sophistication as discussed in the testimony of Witness Schneider. The Rate Design Team will be working with the billing and metering projects to ensure that they will support the types of rate designs that will benefit our customers in the future. The Company presently offers time-of-use rate designs to all metered customer classes to encourage load shifting and offers several DSM programs to control customer appliances to aid in reducing system peak demands.

Q. HOW WILL THE PROPOSED REVENUE INCREASE IMPACT THE RESPECTIVE REVENUE CLASSES?

A. The proposed revenue increase is distributed among customer rate classes by increasing the respective rate schedules as shown in Pirro Exhibit 4, Column N. Pirro Exhibit 2 illustrates the rate class changes and incorporates the effects of migrations and other riders. Pirro Exhibit 7 illustrates the impacts of the proposed revenue increase on the customer classes.

B. Residential Service

Q. PLEASE DESCRIBE THE COMPANY'S RESIDENTIAL SCHEDULES.

A. Rate Schedule RS, Residential Service, will continue to be the basic residential service rate schedule available to all residential customers. Rate Schedule RE, Residential Service – Electric Water Heating and Space Conditioning, will provide customers with qualifying all-electric homes a lower price level in the greater than 350 kilowatt-hours ("kWh") per month block November through June. Schedule RT, Residential Time of Use, will continue to be the Time of Use ("TOU") program available as an option to all residential customers. Additionally, the Company will continue to provide Rate Schedule ES, Residential Service – Energy Star, to customers with homes that meet the qualifications for the Energy Star Program.

Q. DOES THE COMPANY PROPOSE ANY STRUCTURAL CHANGES TO ITS RESIDENTIAL RATES?

A. There are no major structural changes to the Company's residential rates. However, the Company proposes to increase the monthly discount applicable to eligible customers taking service under Rate RS and Rate RE, receiving Supplemental

Security Income ("SSI") under the program administered by the Social Security Administration, and who are blind, disabled, or 65 years of age or over. The discount was authorized by the Commission on August 31, 1978. The Company proposes to increase the maximum discount by approximately 10 to 11 percent to $3.25 for schedule RS and $3.14 for RE, per month. These customers will receive the same increase as other customers, of similar usage patterns, on their respective schedules of Rate RS and Rate RE, less the discount. Schedule RT was adjusted to reflect marginal cost information that supports a reduced emphasis to summer pricing as the difference between summer and winter marginal cost has narrowed over the past years.

Q. WHAT IS THE IMPACT OF THE RATE INCREASE ON THE RESIDENTIAL CUSTOMERS' BILLS?

A. Pirro Exhibit 3, pages 1 and 2, illustrates the impact of the proposed increase on residential customers.

C. General and Industrial Service

Q. DESCRIBE THE COMPANY'S REVIEW OF ITS GENERAL AND INDUSTRIAL RATE SCHEDULES.

A. The Company examined these rates by combining load research and cost of service information to develop profiles of cost. The Company used its rate schedules to develop profiles of revenue by customers that fall within various hours of use (or kWh per kilowatt ("kW")) categories. These profiles of cost and revenue can then be plotted to determine if the profile of revenue deviates from the profile of cost. If significant deviations occur, modifications can be made to the rate structure to reduce the deviation.

Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN OBJECTIVE FOR RATE SCHEDULES SGS, LGS, AND I.

A. Other than revisions to the rate to collect the revised revenue requirement, the Company has not altered the overall structure of Rate LGS, Rate SGS, or Rate I.

Q. WHAT CHANGES TO THE COMPANY'S GENERAL AND INDUSTRIAL RATE SCHEDULES ARE PROPOSED?

A. The Company proposes to increase the incremental demand charge in Rate HP to compensate the Company for increased usage on its distribution system and increased costs at the local distribution level. The standby demand charge based on distribution demand costs and the non-coincident demand is calculated to be $1.7510 per kW and the proposed HP incremental demand charge is $0.8755.

Q. HAVE YOU PREPARED RATE STRUCTURES FOR THE COMMERCIAL AND INDUSTRIAL RATES?

A. Yes. The Company has generally designed its rates utilizing a uniform percentage increase method, which seeks to allocate the additional cost recovery across the various components of each schedule. This maintains the overall structure of the rate without distortion relative to historical design. The energy prices for Schedule OPT-V were adjusted to reflect the overall increase for each OPTV size/voltage category.

The demand rates were then adjusted to achieve the required revenue requirement under each size/voltage category, with slightly more emphasis on winter demand rates as marginal cost information supports a reduced emphasis to summer pricing due to the difference between summer and winter marginal cost narrowing over the past years. This method maintains the overall structure of the rate.

Q. WHAT IS THE IMPACT OF THE RATE DESIGN CHANGES ON NONRESIDENTIAL CUSTOMERS' BILLS?

A. Pirro Exhibit 3, pages 3 through 6, illustrates how the proposed changes to the general and industrial rate designs will affect nonresidential customers.

D. Lighting Rates

Q. IS THE COMPANY PROPOSING TO MAKE CHANGES TO ITS LIGHTING SCHEDULES?

A. Yes. The rates within the lighting schedules were adjusted utilizing a uniform percentage increase method applied to all Existing Pole charges to achieve the resultant revenue requirement for each lighting schedule. This maintains the overall structure of the rate without distortion relative to historical design.

Q. IS THE COMPANY PROPOSING OTHER CHANGES TO ITS LIGHTING SCHEDULES?

A. Yes. Witness Marc Arnold has reviewed the Company's lighting tariffs and is recommending changes to modernize and improve the administration of these schedules. Included in Witness Arnold's recommendations are: proposal to lower the transition fees to balance take-rates while protecting the rate class from pre-mature retirement of assets, proactively replace non-standard and/or decorative MV fixtures with decorative LED fixtures on Schedule OL (private lighting customers), remove the "Inside Municipal Limits" and "Outside Municipal Limits" rate categories in Section A on Schedule PL and rename the rate category as "Existing Pole" to simplify the rates. The Company is also requesting to add a new 530 Watt LED fixture as a replacement for the 750 Watt MH cube fixture.

F. Migrations

Q. DOES THE COMPANY PROPOSE TO REFLECT LOST REVENUES FROM CUSTOMER MIGRATIONS IN ITS GENERAL AND INDUSTRIAL RATE SCHEDULES?

A. Yes. Any time rates are redesigned or modified to produce a different revenue requirement, there is a potential that specific customers may be better off under a different rate schedule than the one under which they are currently billed. Our analysis has determined the migrations among the various rates. The net lost revenue due to these migrations is $6.732 million (rounded). Our experience indicates that, even with notifications described below, only about 50 percent of customers will actually migrate. Accordingly, we have reduced the total amount by 50 percent to $3.366 million (rounded), and this amount has been proportionally allocated to the general and industrial rates based upon their respective increases and used to develop the final design that will allow a reasonable prospect of recovering the revenue requirement.

Q. WHAT WAS THE CRITERIA FOR MIGRATION?

A. For a customer to be considered in the Company's migration analysis, the customer must save at least five percent of its annual bill, and at least $600 annually.

Q. DOES THE COMPANY HAVE A COMMUNICATION PLAN TO ENSURE THAT CUSTOMERS ARE PROPERLY NOTIFIED OF MIGRATION POTENTIAL?

A. Yes. We do. DE Carolinas' Business Relations Managers proactively monitor their assigned customer accounts for savings opportunities and contact customers directly when migration to a different rate schedule should be considered. Additionally, the Business Relations Managers will be provided with information from this rate case regarding potential customer migration opportunities. These steps help to ensure that the amounts we have proposed for migrations are reasonable.

Q. WHY DOES THE COMPANY BELIEVE ITS PROPOSED RATE TREATMENT ASSOCIATED WITH EXPECTED MIGRATIONS IS REASONABLE?

A. Historically, the Company has been able to reflect the effects of customer migrations in the development of its rates. This approach is reasonable for several reasons. First, we provide several rate options to our customers that allow them to select rates most favorable to their respective operations. Second, we will put forth extensive effort to notify customers of potential bill savings. Finally, the Company has adopted a conservative approach in the development of the lost revenues from migrations.

IV. RATE PARITY AMONG THE CLASSES

Q. PLEASE DISCUSS PIRRO EXHIBITS 4 AND 5 AND DE CAROLINAS' CONCERNS REGARDING THE HISTORICALLY SIGNIFICANT RATE DISPARITY AMONG CUSTOMER CLASSES.

A. Pirro Exhibit 4 illustrates the rates of return across classes emanating from the Company's class cost of service study.[1] Pirro Exhibit 5 compares the historical rate of return indices as measured by the ratio of class rate of return to retail rate of return, and it shows that over a lengthy period, residential customers have been subsidized. This historical subsidy has, in the past, been beyond the range of reasonableness, which we define as class rates of return within 10 percent of the total Company rate of return. The updated comparison through the test period year now shows significant convergence of the class rate of return over all classes towards the band of reasonableness demonstrating the success of the strategy of gradually reducing the subsidy/excess by 25 percent. Continuation of this trend would be encouraging and desirable.

The Company remains committed to monitoring subsidy/excess levels and making improvements to ensure its rates are fair across the classes of customers served.

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[1] Pirro Exhibit 4, page 1 of 1, Column N, contains the base rate increases. Pirro Exhibit 2, pages 1 and 2 of 2, illustrates the impacts of the base rate increases plus applicable riders.

V. EXCESS DEFERRED INCOME TAX RIDER (EDIT-2 RIDER)

Q. PLEASE DESCRIBE THE PROPOSED YEAR 1 CREDIT RATES FOR THE NEW EDIT RIDER (EDIT-2).

A. As described in the testimony of Witnesses McManeus and Panizza, the Company will refund amounts owed to customers due to reductions in corporate federal and state income tax rates through a new EDIT-2 Rider. The Year 1 rate credit impact has been included in the revenue increase target used to establish proposed rates in this proceeding. The EDIT-2 Rider Year 1 rates will expire July 31, 2021 and, upon Commission approval, will be replaced August 1, 2021 by the Year 2 rate credit, following the approach outlined in Witness McManeus' testimony.

Q. HOW WAS THE YEAR 1 RATE DETERMINED?

A. The Year 1 revenue requirement was provided by Witness McManeus as shown in McManeus Exhibit 2. The rate schedule revenue requirement was then aggregated to four different rate classes (Residential Service, General Service, Industrial Service and Lighting Service) in order to adhere to the application of Summary of Riders and the Company billing system. Next, the resulting revenue requirement was divided by applicable test year retail billed sales to establish the Year 1 credit rate for each class. The derivation of the credit rate is provided in Pirro Exhibit 9.

VI. IMPLEMENTATION

Q. HOW DOES THE COMPANY PROPOSE THAT THE COMPANY'S TARIFFS, INCLUDING THE PREVIOUSLY DISCUSSED RATES AND CHARGES, BE IMPLEMENTED?

A. DE Carolinas will file with the Commission revised tariffs consistent with the rates and charges approved in the Commission's final order in this case. These compliance tariffs shall become effective on the implementation date set by the Commission unless the Commission suspends the rates or takes other action to prevent implementation of the rates.

VII. RATE SCHEDULE CHANGES

Q. ARE THERE ANY CHANGES TO EXISTING APPROVED TARIFFS?

A. Yes. The Company's proposes changes to its Fuel Cost Adjustment Rider, Existing DSM Program Costs Adjustment Rider, Manually Read Meter Rider and references in various rate schedules to payment due dates.

Q. PLEASE DESCRIBE THE CHANGES BEING PROPOSED TO THE FUEL COST ADJUSTMENT RIDER (LEAF NO. 60).

A. The Company is proposing to change the base fuel component by customer class (excluding gross receipts tax and regulatory fees) as described in Witness McGee's testimony.

- Residential 1.8126 cents per kWh
- General Service 1.9561 cents per kWh
- Industrial 1.8934 cents per kWh

These proposed factors are equal to the total prospective fuel and fuel-related cost factors filed in Docket No. E-7, Sub 1190.

Q. IS THE COMPANY PROPOSING CHANGES TO EXISTING DSM PROGRAM COSTS ADJUSTMENT RIDER (LEAF NO. 64)?

A. Yes. The Company is proposing to decrease the base existing DSM program costs factor from $.000067 per kWh to $.000063 per kWh.

Q. HAS THE COMPANY RECALCULATED THE COSTS ASSOCIATED WITH THE MANUALLY READ METER RIDER ("SMART METER OPT - OUT") SINCE IT WAS APPROVED BY THE COMMISSION?

A. Yes. As directed by the Commission in its June 22, 2018 order in Docket No. E-7, Sub 1115, the Company recalculated the costs associated with its Smart Meter Opt-Out program. The recalculation resulted in the one-time setup charge of $230.80 and a reoccurring monthly charge of $14.05. However, the Manually Read Meter Rider has been in effect less than one year and the Company believes adjusting the fees associated with opt-out is premature. The Company is not proposing to adjust the Smart Meter Opt-Out program fees, which currently includes a $150.00 one-time set up charge and reoccurring monthly charge of $11.75.

Q. PLEASE DESCRIBE THE PROPOSED CHANGE TO THE NON-RESIDENTIAL RATE SCHEDULES RELATED TO BILL PAYMENT DUE DATE.

A. As Witness Henning discusses in his testimony, in response to requests from nonresidential customers for additional time to process electric invoices, the Company is proposing to change when bills are past due and delinquent from fifteen days to twenty-five days to match the current requirement for residential customers. Late payment charges continue to apply after 25 days.

VIII. <u>SERVICE REGULATIONS</u>

Q. ARE THE RATES CONTAINED WITHIN THE SERVICE REGULATIONS BEING UPDATED?

A. Yes. DE Carolinas is seeking changes to several charges to better reflect current cost studies along with the benefits of Smart Meter implementation. Smart Meter technology allows the Company to perform connects and reconnects remotely eliminating the need for a truck roll. These proposed changes include:

1. The Connect Charge decreasing from $24.18 to $10.51.
2. The Reconnect Charge to restore service during normal business hours decreasing from $27.13 to $9.25, and the Reconnect Charge during all other hours decreasing from $27.13 to $10.58 to better reflect the cost of providing these services. The requested change in the reconnect charges primarily reflects a change in the status of outside contractor employed to provide these services along with the benefit of Smart Meter capabilities to perform these activities.

Q. ARE THERE OTHER CHANGES BEING MADE TO THE SERVICE REGULATIONS?

A. Yes. In Section XVI of the Company's proposed service regulations, the revisions include correcting a typographical error and provides references to the service connections for the types of service listed in paragraph 2.

Q. ARE THERE CHANGES BEING MADE TO THE LINE EXTENSION PLAN?

A. Yes. In Section II, the definition of Standard Design has been revised to reflect the Company's design and construction practices. Also, the definition of the overhead point of delivery has been revised to reflect the Company's policy and construction practices.

Section VII, Provision 10, regarding payment of contribution-in-aid of construction, has been modified to more clearly reflect the Company's intent of when payments are required. In Provision 11, the Company has corrected a typographical error.

IX. CONCLUSION

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

A. Yes.

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202. I am Director, Southeast Pricing & Regulatory Solutions for Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company"), Duke Energy Progress, LLC, and Duke Energy Florida, LLC.

Q. ARE YOU THE SAME MICHAEL J. PIRRO WHOSE DIRECT TESTIMONY AND EXHIBITS WERE FILED IN THIS DOCKET?

A. Yes. I filed Direct Testimony and Exhibits on September 30, 2019 and corrected direct testimony on October 23, 2019.

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

A. The purpose of my supplemental direct testimony is to address the Company's updates to its proforma adjustments to test period amounts relating to customer growth and weather normalization. My testimony also clarifies the methodology the Company used to spread the Excess Deferred Income Tax ("EDIT") rider ("EDIT-2 Rider") amongst customer classes.

Q. PLEASE DESCRIBE THE COMPANY'S CHANGES TO ITS PROFORMA ADJUSTMENT TO CUSTOMER GROWTH.

A. This adjustment has been updated to reflect actual customer growth data and weather impacts through January 2020. The net increase in kWh for Lighting (besides Schedule TS) no longer includes consideration for the change in average usage per customer. The Customer by Customer approach, where it is being used to calculate an adjustment to General Service and Industrial kWh sales, now excludes each account's first month of available usage data when calculating the total kWh gain of Openings in the Test Period and Openings in the Extended Period. The average cents per kWh for residential has been revised to remove the basic facilities charge component, with a separate component being added to reflect the customer growth impact on revenues from residential basic facilities charges.

Q. PLEASE DESCRIBE THE COMPANY'S CHANGES TO ITS PROFORMA ADJUSTMENT TO NORMALIZE FOR WEATHER.

A. This adjustment has been updated to incorporate additional months of actual sales and weather data through January 2020. In addition, the average cents per kWh for the residential class has been revised to remove the basic facilities charge component.

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO SPREAD THE EDIT-2 RIDER AMONGST CUSTOMER CLASSES.

A. The EDIT-2 rider for North Carolina was allocated to the customer classes based on how accumulated deferred income tax was allocated in the Company's 2018 per books cost of service study under the 1 Summer Coincident Peak case. In order to develop the EDIT-2 rider rates, that conform to DE Carolinas' Summary of Riders Schedule along with IT/billing requirements, rate design grouped the allocated costs into four classes (Residential, General, Industrial, and Lighting). The rate class revenue requirement was then divided by test year retail billed sales to establish the Year 1 credit rate. The derivation of the credit rate applicable to each rate class is provided in Pirro Exhibit 9. Furthermore, the proposed EDIT-2 rider rates, by class, were then multiplied by the kWh by rate schedule to develop the amounts shown in Pirro Direct Exhibit 4, Column M.

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

A. Yes.

I. INTRODUCTION AND PURPOSE

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, NC 28202. My current position is Director, Southeast Pricing & Regulatory Solutions for Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and its affiliated utility operating companies.

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

A. Yes. I filed direct testimony supporting DE Carolinas' overall rate design and sponsoring the proposed tariffs in this proceeding. I also filed corrected direct testimony on October 23, 2019 and supplemental direct testimony on February 14, 2020.

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

A. The purpose of my testimony is to rebut various points and issues raised by intervenors in this docket regarding:

1) RESIDENTIAL BASIC FACILITIES CHARGE ("BFC") as discussed in the testimony of North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy (collectively, "NC Justice Center, et al.") Witnesses Jonathan Wallach and John Howat;

2) CUSTOMER GROWTH and WEATHER NORMALIZATION ADJUSTMENTS as discussed in the testimony of Public Staff Witness Scott Saillor;

3) OPTV PRICING as discussed in the testimony of Carolina Industrial Group for Fair Utility Rates III ("CIGFUR") Witness Nicholas Phillips and Harris Teeter Witness Justin Bieber; and

4) HOURLY PRICING as discussed in the testimony of CIGFUR Witness Phillips and Carolina Utility Customers Association, Inc. ("CUCA") Witness Kevin O'Donnell.

II. <u>RESIDENTIAL BASIC FACILITIES CHARGE</u>

Q. DID THE COMPANY PROPOSE AN ADJUSTMENT TO THE RESIDENTIAL BASIC FACILITIES CHARGE?

A. No. DE Carolinas proposed no change to the current BFC of $14.00 in this proceeding. The Company generally supports setting the BFC to recover approximately 50 percent of the difference between the current rate and the full customer-related unit cost incurred to serve these customer groups as current rates significantly understate the current unit cost of service related to the customer component of cost. However, the Company has decided in this case to leave the BFC at current rates due to past concerns raised by low-income and other advocates with respect to the level of the charge. Instead, the Company supports a collaborative to discuss opportunities to address low-income, fixed income, and low-usage customer concerns. The BFC may be addressed in future proceedings to properly reflect equitable cost-based rates that provide accurate price signals to our customers.

Q. SEVERAL INTERVENORS ALLEGE THAT THE COSTS IDENTIFIED BY THE MINIMUM SYSTEM METHODOLOGY ARE NOT CUSTOMER COSTS AND SHOULD NOT BE INCLUDED IN THE BFC. DO YOU AGREE WITH THAT ALLEGATION?

A. No. The rates and rate design supported by my testimony are based upon the cost of service study, including the minimum system cost study, performed by the Company, accepted by Public Staff, and approved in previous rate cases by the Commission. The Company's cost of service studies indicate that these costs are Customer Costs and therefore the BFC was designed to recover them.

Q. DO YOU AGREE WITH INTERVENORS' POSITION OF REDUCING THE CURRENT RESIDENTIAL BFC?

A. No. The Company's current residential BFC should remain in effect in this proceeding.

Q. RATE SCHEDULE RS, THE COMPANY'S PRIMARY RESIDENTIAL RATE SCHEDULE, DOES NOT HAVE A DEMAND COMPONENT; RATHER, IT ONLY HAS A BFC AND A VOLUMETRIC PER KWH CHARGES. WOULD IT BE APPROPRIATE TO SHIFT SOME OF THE COSTS CURRENTLY INCLUDED IN THE BFC TO A VOLUMETRIC RATE?

A. No. As Witnesses Howat and Wallach recognize in their direct testimony, the distribution facilities costs in question represent poles, conductors, conduit, and transformers. These costs are fixed in nature and do not vary with customer consumption just like the metering, service drops, and billing costs for which they support and recognize the appropriateness of a per customer charge. Importantly, they are unlike variable operation and maintenance costs and fuel costs which vary directly with energy consumption and are properly recovered via the volumetric kWh rate. Thus, recovering such costs via a kwh charge would provide an incorrect pricing signal.

Q. ARE WITNESSES WALLACH AND HOWAT CORRECT IN ASSERTING THAT THE CURRENT BFC DISCOURAGES DISTRIBUTED GENERATION AND ENERGY EFFICIENCY?

A. No. Failing to properly recover customer-related costs via a fixed monthly charge would provide an inappropriate price signal to customers and would fail to adequately reflect cost causation. Shifting customer-related costs to a volumetric per kWh rate further exacerbates this concern and overcompensates energy efficiency and distributed generation for the cost avoided by their actions, thereby skewing the market for such measures.

Q. DOES THE CURRENT BFC DISPROPORTIONATELY HARM LOW-INCOME CUSTOMERS AS ARGUED BY WITNESS HOWAT?

A. The Company is mindful of the impact of any rate increase on our customers, particularly low-income customers; however, the Company does not design rates based upon customer incomes, but rather applies cost causation principles to the extent practical. There are other means of addressing the financial needs of low-income customers, such as Company, state, and local programs, which are more effective than biasing the rate design.

For example, energy efficiency programs, including the Company's Residential Income Qualified Energy Efficiency and Weatherization Assistance Program, aid low-income customers in reducing their consumption of energy at no cost to the consumer. Other Company programs, such as budget billing and payment arrangements, are available to assist low-income customers and others in managing their cost for electricity. The Energy Neighbor Fund is promoted by the Company and raises funds for local aid agencies to assist low-income customers. These initiatives are more effective than biasing the rate design to aid low-usage customers. Finally, inappropriately pricing the BFC below cost tends to subsidize all low-usage customers, and not just low-income customers. Moreover, not all low-income customers are low-usage customers.

Q. WITNESS HOWAT ALSO SEEKS CHANGES TO THE COMPANY'S ENERGY EFFICIENCY PROGRAMS TARGETING LOW-INCOME CUSTOMERS. ARE SUCH PROGRAMS INCLUDED IN THE COMPANY'S PROPOSAL?

A. No. Rate design involves allocating a utility's actual generation, transmission, distribution and customer costs determined by a cost of service study to the utility's customer classes and developing rates to recover those costs. In designing proposed customer rates to generate DE Carolinas' revenue requirement, it is inappropriate to consider energy efficiency programs that have not been approved by the Commission. Revenues for energy efficiency programs are intentionally excluded from rate case revenues since they are considered annually in a demand-side management and energy efficiency ("DSM/EE") cost recovery proceeding. The issue of whether DE Carolinas should propose additional energy efficiency programs or modify existing energy efficiency programs should be addressed in DE Carolinas' DSM/EE proceedings.

III. <u>CUSTOMER GROWTH, CHANGE IN USAGE AND WEATHER NORMALIZATION ADJUSTMENTS</u>

Q. DOES THE COMPANY AGREE WITH PUBLIC STAFF WITNESS SAILLOR'S MODIFICATIONS TO THE COMPANY'S CUSTOMER GROWTH AND WEATHER NORMALIZATION ADJUSTMENTS?

A. Yes. The Company agrees in principle with the proposed recommendations from Public Staff Witness Saillor, though application may vary slightly.

Q. PLEASE DESCRIBE THE AGREED UPON MODIFICATIONS.

A. The Company and Public Staff Witness Saillor agree to the following modifications to the Adjustments to Annualize Revenues for Customer Growth and Change in Usage:

- Modifying the Customer-by-Customer Approach for Openings in the Test Period by determining average monthly usage through taking the average of the 12 months of billing data following initial month of service;
- Modifying the Customer-by-Customer Approach for Openings in the Extended Period by removing the initial month of service from the average usage calculation;
- The removal of Basic Facilities Charge revenues from the change in usage calculations;

- The removal of the change in usage revenue adjustment for the Lighting rate class; and
- The inclusion of a change in usage adjustment for the General and Industrial rate classes.

The Company and Public Staff Witness Saillor agree to the following modifications to the Weather Normalization Adjustment:

- The removal of BFC revenues from the calculations of average customer class rates; and
- Summing of the monthly NC Retail kWh weather adjustments within the test period for each customer class in place of multiplying the test period System Retail kWh weather adjustment times the annual NC Retail-to-System sales ratio.

IV. OPTV RATES

Q. PLEASE DESCRIBE OPTV RATE STRUCTURE AND CUSTOMER ACCEPTANCE.

A. The Company's Rate Schedule OPTV is well received and very popular among the commercial and industrial customer base, as it offers variation in pricing to incent changes in usage behavior. The Company, in Docket No. E-7, Sub 1026, filed DE Carolinas' OPT Rate Schedule criteria. The redesign of OPT was fully vetted and agreed upon by both CUCA and CIGFUR and approved by the Commission. The Company diligently pursued a fair and equitable cost-based resolution, as all subsidy/excess revenues were eliminated within the OPT class. The approved redesign ultimately focused the increase to the on-peak portion of the rate in order to send a stronger price signal for off-peak usage. The rate structure consists of three voltage levels: transmission, primary, and secondary. Within the primary and secondary voltage levels there are three separate sizes of load (small, medium, and large) for a total of seven different rate offerings within OPTV.

Q. DO YOU AGREE WITH CIGFUR WITNESS PHILLIPS' AND HARRIS TEETER WITNESS BIEBER'S PROPOSED CHANGES TO OPTV-T, OPTV-PL, AND OPTV-SS?

A. No. Both witnesses appear to be supportive of cost-based rate design. However, both miss an important translation between cost of service and rate design. Rate design needs to look at the rate structure and provide balance (customer, demand, and energy) to provide an accurate price signal to customers. The rate designer's task is to design a rate that best mimics the cost of serving customers across a range of usage without all cost elements being strictly defined by the rate structure.

An industry method used to accomplish this is to allocate a portion of demand costs to be included in the energy charge. The simplistic notion that all demand costs be included in a demand charge and all energy costs be included in an energy charge would essentially invalidate most of the rate structures in the industry across the country. Also, if rates increase, more and more costs would be unjustifiably borne by the lower load factor customers in the group with the methods advocated by the intervenors. This would decrease their competitiveness and cause real economic harm, while their higher load factor counterparts would enjoy the results of a mispriced product.

The Company's proposed structure and pricing, as modified by the Commission's final determination of revenue requirement, should be approved.

V. HOURLY PRICING RATES

Q. PLEASE DESCRIBE THE HOURLY PRICING FOR INCREMENTAL LOAD (SCHEDULE HP) THAT IS AVAILABLE TO THE COMPANY'S LARGE CUSTOMERS.

A. Schedule HP (Hourly Pricing) is a voluntary rate option that offers customers the opportunity to purchase incremental energy differing from a baseline load at rates that more closely match the Company's incremental cost of providing the kWh in the given hour. Participants understand that hourly rates will vary throughout the year and therefore offer opportunities to change consumption and benefit from the variable pricing. It is available to nonresidential customers with a contract demand requirement of 1,000 kW or greater and allows usage above or below a baseline amount to be billed at a rate that varies each hour to reflect the Company's marginal cost. Hourly rates are provided to participants on the prior business day. Baseline usage is billed under an applicable standard tariff selected by the customer, while the incremental use is billed at the hourly rate. The hourly rate includes the expected marginal production costs including line losses and other directly-related cost. An incremental demand charge and incentive margin also apply to incremental load additions.

Q. HOW ARE HOURLY RATES UNDER SCHEDULE HP CALCULATED?

A. Hourly rates are calculated based upon the marginal or dispatch cost of the generator that is expected to serve the next kWh of system load based upon all available generating plants. Hourly rates are based on variable production cost data from an industry standard production cost model which is updated daily to reflect the latest available information such as weather and load forecast, unit availability, heat rates, and variable commodity and emission costs. Hourly rates derived from the production cost model data reflect the change in the Company's fuel and other directly related variable costs that would be anticipated if the customer decides to exceed or reduce load from their baseline load. The determination of the marginal cost is also consistent with the methodology used by the Company to price opportunity sales into the wholesale market.

Q. DO YOU AGREE WITH THE RECOMMENDATION OF CIGFUR WITNESS PHILLIPS THAT RATE SCHEDULE HP BE AVAILABLE FOR EXISTING LOAD?

A. No. Schedule HP was established to provide customers with an opportunity and flexibility to respond directly, through usage behavior, to short term costs meaning a customer could reduce load under temporarily high prices and increase usage when prices are low, in which case they would benefit. Furthermore, applying HP to existing baseload usage would discriminately provide a discount to few customers, therefore shifting costs to the remaining customers on the standard tariff schedule.

Q. IS THE RECOMMENDATION OF CUCA WITNESS O'DONNELL THAT THE HOURLY RATE BE SET AT THE LOWER OF THE COMPANY'S MARGINAL COST OR A WHOLESALE MARKET RATE APPROPRIATE?

A. No. The Schedule HP hourly rates are fundamentally based on the Company's system production costs and are not designed to represent or be a proxy for market-based pricing. The rate is designed to afford customers the opportunity and flexibility to respond directly, through usage, to short term system costs. It is more analogous to a synthetic bi-directional demand response product than a market-based product. Customers can increase usage as befits their process during periods of low system costs or decrease their usage during periods of higher system costs. DE Carolinas actively participates in the wholesale energy market to the practical limitations of system reliability, transmission availability, and market liquidity, and customers benefit in the aggregate from those market purchases. The HP product is not a market product and was never intended to provide some customers with optionality beyond the ability of the Company to provide appropriately priced service. Applying hourly rates that are lower than the Company's marginal system cost would result in other customers subsidizing Hourly Pricing customers. The current methodology best reflects the Company's expected fuel cost and is therefore the appropriate basis under which to set hourly rates.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202. My position with Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") recently changed to Director, Load Forecasting and Fundamentals.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony and exhibits on September 30, 2019, corrected direct testimony on October 23, 2019, supplemental direct testimony and exhibits on February 14, 2020, and rebuttal testimony on March 4, 2020.

Q. WHAT IS THE PURPOSE OF TESTIMONY?

A. The purpose of my second supplemental direct testimony is to support the Company's proposed update to its customer growth adjustment to incorporate certain known and measurable changes through May 31, 2020.

Q. DID YOU PROVIDE ANY INFORMATION INCLUDED IN EXHIBITS SPONSORED BY OTHER COMPANY WITNESSES?

A. Yes. For the reasons I describe below, I sponsor the following adjustment presented in McManeus Second Supplemental Exhibit 1:

Line 4 – Annualize revenues for customer growth.

Q. WHY IS THE COMPANY UPDATING ITS CUSTOMER GROWTH ADJUSTMENT?

A. The Company is experiencing a significant reduction in its load and associated revenues due to many commercial and industrial customers as well as schools and colleges scaling back operations, if not closing completely, during the COVID-19 state of emergency. In addition, the Company has experienced an increase in residential usage. The Company believes that reflecting these changes closer in time to the rescheduled hearing will result in a more accurate depiction of the Company's load forecast and customer usage. Accordingly, the Company has updated its pro forma adjustment for customer growth to reflect known and measurable kilowatt hour changes in residential and non-residential usage through May 31, 2020.

Q. DOES THIS CONCLUDE YOUR PRE-FILED SECOND SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Second Supplemental Direct Testimony and Exhibits of Jane L. McManeus and Second Supplemental Direct Testimony of Michael J. Pirro*, as filed in Docket Nos. E-7, Sub 1214; E-7, Sub 1213; and E-7, Sub 1187, was served via electronic delivery or mailed, first-class, postage prepaid, upon all parties of record.

This, the 2nd day of July, 2020.

/s/Camal O. Robinson
Camal O. Robinson
Associate General Counsel
Duke Energy
550 South Tryon Street
Charlotte, North Carolina 28202
Telephone: (980) 373-2631
mgrigg@mcguirewoods.com

Attorney for Duke Energy Carolinas, LLC

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202. My position with Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") recently changed to Director, Load Forecasting and Fundamentals.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony and exhibits on September 30, 2019, corrected direct testimony on October 23, 2019, supplemental direct testimony and exhibits on February 14, 2020, rebuttal testimony on March 4, 2020, and second supplemental direct testimony on July 2, 2020.

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

A. My second settlement testimony provides updates to Pirro Exhibit 4 and Pirro Exhibit 9 to reflect the First Agreement and Stipulation of Partial Settlement between the Company and the Public Staff filed on March 25, 2020 ("First Partial Settlement"), the Second Agreement and Stipulation of Partial Settlement between the Company and the Public Staff filed on July 31, 2020 ("Second Partial Settlement"), and the Company's Agreement and Stipulation of Settlement with CIGFUR III filed on May 29, 2020, as amended on August 6, 2020 ("CIGFUR Settlement").

Q. WERE THE EXHIBITS TO YOUR SECOND SETTLEMENT TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. PLEASE DESCRIBE THE UPDATE TO PIRRO EXHIBIT 4.

A. Pirro Direct Exhibit 4 illustrates the rates of return across classes emanating from the Company's class cost of service study and shows how the proposed revenue increase is distributed among customer rate classes. Pirro Second Settlement Exhibit 4 updates Pirro Direct Exhibit 4 to reflect the revised revenue requirement resulting from the Second Partial Settlement and the Company's position on unsettled items, as further supported by Company witness Jane McManeus's second settlement testimony. This update shows the rate increase by customer class and proposed spread to customer classes, both with and without the proposed Excess Deferred Income Tax ("EDIT") Rider. The EDIT Rider amounts reflected in Column M of this exhibit have been updated as described below.

Q. PLEASE DESCRIBE THE UPDATE TO PIRRO EXHIBIT 9.

A. Pirro Direct Exhibit 9 provides the derivation of the Company's original proposed EDIT Rider through which the Company proposes to refund amounts owed to customers due to reductions in corporate federal and state income tax rates. As a result of the Company's First Partial Settlement with the Public Staff, the Company has agreed to return protected federal EDIT to customers through base rates instead of the EDIT Rider. In addition, as described in the Second Partial Settlement, the Company and the Public Staff have agreed that all unprotected federal EDIT should be returned to customers over a five-year amortization period and that North Carolina EDIT and deferred revenues related to the provisional overcollection of federal income taxes should be returned to customers over a two-year amortization period. Under the CIGFUR Settlement, the Company has agreed to refund unprotected EDIT and deferred revenues to customers on a uniform cents per kilowatt-hour basis. Pirro Second Settlement Exhibit 9 recalculates the proposed EDIT Rider rate credits to reflect these provisions of the First Partial Settlement, Second Partial Settlement, and CIGFUR Settlement.[1]

Q. DOES THIS CONCLUDE YOUR SECOND SETTLEMENT TESTIMONY?

A. Yes.

[1] Pirro Second Settlement Exhibit 9 displays the two-year decrement rider amounts resulting from the settlements as “EDIT-3” and the five-year decrement rider amounts as “EDIT-4.”

MS. JAGANNATHAN: I would also move that the summary of Mr. Pirro's testimony be moved into the record as if given orally from the stand.

CHAIR MITCHELL: Again, hearing no objection, that motion will be allowed.

(Whereupon, the prefiled testimony summary of Michael J. Pirro was copied into the record as if given orally from the stand.)

Duke Energy Carolinas, LLC
Summary of Testimony of Michael J. Pirro
Docket No. E-7, Sub 1214

My direct testimony explains how the rates and charges that Duke Energy Carolinas proposes are based upon appropriate and sound ratemaking principles and that they result in an equitable basis for recovery of the Company's revenue requirement across and within its various rate schedules. My testimony also describes changes to the Company's retail electric schedules and quantifies the effect of these changes to retail customers. The proposed rates appropriately reflect the cost of service within the four major rate classes: residential, small and large general service, industrial, and various outdoor lighting schedules.

I used the cost of service information prepared by the Company and supported by witness Hager as a major component for the rate design. As witness Hager describes in her testimony, the cost of service study allocates costs to the jurisdictions and various rate classes and separates the customer, demand, and energy components of cost. I also reviewed and considered the rates of return across the customer classes derived from the cost of service study.

The Company did not propose any structural changes within each tariff except for the lighting class. As detailed in the rebuttal testimony of witness Huber and agreed to in the Second Partial Settlement with the Public Staff, the Company is planning a comprehensive rate design study following the conclusion of this rate case, which will include consideration of a number of new and innovative rate design issues.

The rate adjustments proposed by the Company in this proceeding are intended to move all rate schedules closer to a more equitable pricing structure. The Company is seeking to achieve an equitable pricing structure in steps in recognition that the imbalance in class and rate schedule returns did not occur overnight and should not be corrected overnight. A framework that reflects these rate design concepts – gradualism and parity – is also reflected in the Second Partial Settlement.

Duke Energy Carolinas, LLC
Summary of Testimony of Michael J. Pirro
Docket No. E-7, Sub 1214

In my rebuttal testimony, I address a number of rate design issues raised by various intervenors, many of which have since been resolved by settlement agreements with those intervenors. In addition, I respond to the only intervenor group that took issue with the residential Basic Facilities Charge, noting that the Company purposefully did *not* propose any increase to the Basic Facilities Charge in this case due to concerns raised by this group and other advocates for low-income customers in the Company's last rate case.

I also filed supplemental testimony supporting the Company's proposed update to its customer growth adjustment to incorporate certain known and measurable changes through May 31, 2020. In the Second Partial Settlement, the parties agreed to limit any resulting increase in revenues to 75% of the difference between the May update and the Company's January 2020 update to recognize the uncertainty regarding the effects of COVID-19. Finally, I filed settlement testimony to support updates to my exhibits to reflect the impact of various settlement agreements.

This concludes the summary of my pre-filed testimony.

MS. JAGANNATHAN: Thank you, Chair Mitchell. And, finally, I would move that Pirro Exhibits 1 through 9 and Pirro Second Settlement Exhibit 4 and Pirro Second Settlement Exhibit 9 be marked for identification.

CHAIR MITCHELL: They will be marked as prefiled.

(Pirro Exhibits 1 through 9, and Pirro Second Settlement Exhibits 4 and 9, were identified as they were marked when prefiled.)

MS. JAGANNATHAN: Thank you.

Q. And last but not least, Mr. Huber, would you please state your name and business address for the record?

A. (Lon Huber) Sure. My name is Lon Huber, and my business address is 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy business services as vice president of rate design and strategic solutions.

Q. And, Mr. Huber, on March 4, 2020, did you cause to be prefiled in this docket, rebuttal testimony consisting of eight pages and a one-page appendix describing your experience and qualifications?

A. Yes, I did.

Q. And do you have any changes or corrections to your prefiled testimony, Mr. Huber?

A. Yes, I have one update that is included in the errata page provided with my testimony summary.

Q. And with the correction to your rebuttal testimony that was included in the errata, if I asked you the same questions here today, would your answers be the same?

A. Yes, they would.

MS. JAGANNATHAN: Chair Mitchell, I would move that Mr. Huber's prefiled rebuttal testimony as corrected in the errata page and Appendix A, as well as his testimony summary, be entered into the record as if given orally from the stand.

CHAIR MITCHELL: Hearing no objection, your motion is allowed.

MS. JAGANNATHAN: Thanks, Chair Mitchell.

(Whereupon, the prefiled rebuttal

testimony with Appendix A and testimony summary and errata of Lon Huber were copied into the record as if given orally from the stand.)

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS.

A. My name is Lon Huber, and my business address is 550 South Tryon Street, Charlotte, NC 28202.

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

A. I am employed by Duke Energy Corporation ("Duke Energy"). My role is Vice President, Rate Design and Strategic Solutions. In this capacity, I am responsible for rate design and pricing for all of Duke Energy's affiliated utility operating companies, including Duke Energy Carolinas ("DE Carolinas" or "Company") and Duke Energy Progress, LLC ("DE Progress").

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

A. No.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. My career in the energy industry began in 2007, when I started work at a solar energy research institute housed within the University of Arizona. From 2010 to 2013, I held positions in the solar industry working on matters both local to Arizona and across the United States. Subsequently, I served as a consultant for Arizona's consumer advocate, the Residential Utility Consumer's Office ("RUCO"), on energy-related issues. I then joined RUCO as a full-time employee. At RUCO, I was the staff lead on significant dockets involving net metering, resource procurement, and rate design. I decided to rejoin the consulting space in 2015, where I worked for numerous consumer advocates, state utility commissions, and energy companies across the country. A major topic of my work was around pricing and rate design with a specialty in time-varying rates and subscription-based pricing. I have also been a regular instructor at the Financial Research Institute Transformational Pricing course held at the University of Washington. Due to my work on rate design and other matters like energy storage, I have garnered recognition for my creative win-win solutions including Utility Dive's 2018 Innovator of the Year award. I assumed my current position with Duke Energy in November of 2019.

In terms of educational background, I obtained a Bachelor of Science degree in Public Policy and Management from the University of Arizona. I also received a Master of Business Administration from the Eller College of Management at the same university. I completed NARUC rate school in 2014. My full resume is included as Appendix A.

Q. HAVE YOU TESTIFIED BEFORE THE NORTH CAROLINA UTILITES COMMISSION BEFORE?

A. No, I have not.

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

A. My rebuttal testimony responds to:

- COMPREHENSIVE RATE DESIGN STUDY as discussed in the testimony of Public Staff Witness Jack L. Floyd; and

- INTERRUPTIBLE RATES AND EV-SUPPORTIVE RATE DESIGN as discussed in the testimony of Carolina Utility Customers Association, Inc. ("CUCA") Witness Kevin W. O'Donnell and in the testimony of the North Carolina Sustainable Energy Association ("NCSEA") Witness Justin R. Barnes.

II. <u>COMPREHENSIVE RATE DESIGN STUDY</u>

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS JACK FLOYD THAT THE COMPANY SHOULD CONDUCT A COMPREHENSIVE RATE DESIGN STUDY?

A. Yes. The Company supports an open, data-driven process that does not preclude or favor any predetermined conclusions. Historically, DE Carolinas' rate offerings have adequately served customers, with all rate classes being able to choose between a standard and time-of-use rate schedules. However, changes in customer interests, political and regulatory priorities, and increasing adoption of new technologies demand a rethinking of DE Carolinas' rate designs.

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS JACK FLOYD'S OPINION ON THE REQUIRED COMPONENTS OF A COMPREHENSIVE RATE DESIGN STUDY?

A. Yes. A comprehensive rate design study should result in new designs that better meet the state's public policy goals. Thus, the Company agrees with Witness Floyd's six broad principles for a comprehensive rate design study, including that it:

1) Be forward-looking and reflect long-run marginal cost;

2) Be focused on the usage components of service that are the most cost- and price-sensitive;

3) Be simple and understandable;

4) Recover system costs in proportion to how much electricity consumers use, and when they use it;

5) Give consumers appropriate information and the opportunity to respond to that information by adjusting the usage; and

6) Where possible, be dynamic.

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS JACK FLOYD'S COMMENTS THAT A COMPREHENSIVE RATE DESIGN STUDY SHOULD SEEK TO HARMONIZE THE RATE DESIGN STRUCTURES OF DE CAROLINAS AND DE PROGRESS?

A. Yes. Both utilities have retained the same basic rate design structure from before the merger. As Witness Floyd mentioned, this is confusing and often frustrating for customers. Better aligning the rate designs may create some synergies for the Company, as the differences also present operational challenges. A comprehensive rate design study should explore how creating a unified pricing theory and better aligning the two utilities would help achieve the aforementioned rate design goals.

Q. WHAT FACTORS NEED TO BE CONSIDERED IN SETTING A TIMEFRAME FOR A COMPREHENSIVE RATE DESIGN STUDY?

A. Public Staff Witness Floyd suggested that the Company undertake a comprehensive rate design study prior to the filing of its next rate case. He noted that such a study is "no trivial matter," and will be a "serious and lengthy undertaking" which will involve many stakeholders and will likely require a significant amount of time to develop and implement. While DE Carolinas does not currently know the timing of its next rate case, the Company has already begun analyzing data and plans to convene stakeholders in a collaborative process before refining its rate design proposals. The Company notes that it cannot cost-effectively implement any rate design changes until the new Customer Connect billing system is in use. Because it is more cost-effective to implement new rates concurrently with the new billing system, DE Carolinas strongly favors utilizing the time prior to implementation to analyze data, convene stakeholders, and refine its proposals. Customer Connect is scheduled to be implemented in DE Carolinas for the spring of 2021. Once the new Customer Connect system is fully deployed and post-deployment stabilization is achieved approximately six months later, the Company will be ready to begin implementing new rate designs.

Q. WHAT TIME FRAME DOES THE COMPANY RECOMMEND?

A. Given the considerations noted previously, the Company proposes to complete the comprehensive rate design study by the end of the second quarter of 2021. The Company believes that this is an aggressive timeline that will allow the new rate designs to be implemented as soon as Customer Connect is ready to support any proposed changes.

Q. IS DE CAROLINAS CURRENTLY COLLECTING DATA THAT WILL BE BENEFICIAL FOR A COMPREHENSIVE RATE DESIGN STUDY?

A. Yes. DE Carolinas started providing service under nine new dynamic pricing pilots effective October 1, 2019, in compliance with the Commission's July 2, 2019 *Order Approving Pilots* in Docket No. E-7, Sub 1146. The Commission is also currently considering the Company's Proposed Electric Transportation Pilot in Docket No. E-7 Sub 1195. DE Carolinas will incorporate the lessons gleaned from these pilots to better inform future rate design proposals, in addition to any comprehensive study. In addition, deployment of smart meters throughout DE Carolinas is nearly complete, offering an additional level of insight and data that will be used to design refreshed rates.

III. INTERRUPTIBLE RATES AND ELECTRIC VEHICLE-SUPPORTIVE RATE DESIGN

Q. IS DE CAROLINAS OPEN TO REEXAMINING ITS CURTAILABLE OPTIONS OR LOOKING INTO RATE DESIGNS THAT SUPPORT THE ADOPTION OF ELECTRIC VEHICLES, AS SUGGESTED BY CUCA WITNESS KEVIN O'DONNELL AND NCSEA WITNESS BARNES, RESPECTIVELY?

A. Yes. The Company recognizes the benefits that curtailable customers provide to the system and is interested in exploring how to maximize this value while also recognizing the benefits of the grid's supporting infrastructure. Similarly, DE Carolinas understands that increasing the adoption of electric vehicles is a state policy goal that could provide significant system benefits. A re-examination of curtailable offerings and study of rate designs that facilitate the adoption of electric vehicles that provide system benefits for all customers will be a part of any comprehensive rate design study. In the context of a comprehensive study, any new or altered offerings can be crafted to work in concert with the other components of DE Carolinas' rate designs.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

Lon Huber

Lon.Huber@Duke-Energy.com

Experience

Vice President – Rate Design and Strategic Solutions
Nov 2019 -
Duke Energy – Charlotte, NC

Director – North American Retail Regulatory Offering
July 2018 – Nov 2019
Navigant Consulting – New York, NY

Vice President – Head of Consulting
MAR 2015 – JULY 2018
Strategen Consulting – Berkeley, CA

Special Projects Advisor
APR 2013 – MAR 2015
Arizona's Residential Utility Consumer Office (RUCO) – Phoenix, AZ

Founder
DEC 2010 – JAN 2014
Next Phase Energy – Tucson, AZ

Manager – Policy Specialist
SEP 2011 – DEC 2012
Suntech America – San Francisco, CA

Finance & Policy Lead
SEP 2010 – SEP 2011
TFS Solar – Tucson, AZ

Congressional Energy Fellow
JAN 2009 – MAY 2009
Washington DC

Policy Program Associate
AUG 2007 – SEP 2010
University of Arizona Research Institute for Solar Energy – Tucson, AZ

EDUCATION

Masters of Business Administration
Eller College of Management, 2011

BS, Public Policy and Management,
University of Arizona, 2009

EDUCATION/CERTIFICATIONS

Instructor – FRI's Transformational rate design course

Microsoft Office Excel Specialist

NARUC Utility Rate School Graduate

AWARDS

Fortnightly Under 40 and Top Innovator Honor Roll – Public Utilities Fortnightly

2018 Innovator of the Year – Utility Dive

The Phil Symons Award – Energy Storage Association

40 under 40 – Arizona Daily Star

Young Alumni Award and Outstanding Professional Staff Member – University of Arizona

Congressional Recognition Award – US House of Representatives

Duke Energy Carolinas, LLC
Summary of Rebuttal Testimony of Lon Huber
Docket No. E-7, Sub 1214

I joined Duke Energy less than a year ago as Vice President of Rate Design and Strategic Solutions. In this role, I am responsible for rate design and pricing for all of Duke Energy's affiliated utility operating companies, including Duke Energy Carolinas. I appreciate the opportunity to appear before this Commission for the first time. While Mr. Pirro's testimony covers the rate designs filed as part of this rate case, I cover forward-looking rate design topics that have been raised by intervenors, including the opportunity to revamp the Company's rate design in a comprehensive rate design study, as well as rate design issues relating to electric vehicles.

While I may be new to my role at Duke Energy, the core issues at hand are not new to me. As a former consultant, I have worked across the country on rate design topics, mainly for public utility commissions and state consumer advocates. In those roles, I saw how converging trends in the industry are driving the need for rate design modernization. I was fortunate to be able to see consumer and technological trends firsthand in states on the front lines of change. For example, I was a consultant for four years at the Hawaii Public Utilities Commission, I worked on rate design for Xcel and Minnesota Power, I was an employee and consultant of the Arizona consumer advocate office for five years, I have advised the New York Public Service Commission, and I consulted for the Attorney General's office in Massachusetts for several years. I aim to bring these experiences and insights to my role at Duke Energy and work collaboratively with stakeholders to analyze current North Carolina rate designs, and where appropriate, modernize the Company's offerings.

To that end, in my rebuttal testimony, I agree with Public Staff witness Jack Floyd that the time is right for the Company to undertake a comprehensive rate design study following this rate case. While historically, the Company's rate offerings have served its customers well, changes in customer interests, policy and regulatory priorities, and increasing adoption of new technologies require a rethinking of Duke Energy Carolinas' rate designs. In addition, deployment of smart meters throughout DE Carolinas is nearly complete, offering an additional level of insight and data that will be used to design refreshed rates. Lessons learned from recently filed dynamic pricing pilots and the Company's proposed electric vehicle pilot will also be used to inform future rate design proposals.

The Company has begun analyzing data and plans to convene stakeholders in a collaborative process before refining its rate design proposals. Duke Energy Carolinas initially proposed to complete the comprehensive rate design study by the end of the second quarter of 2021, which would have given the Company a year to engage stakeholders and complete the study had the hearing proceeded as originally scheduled. In light of the delays caused by the unprecedented events of 2020, the Company proposes to complete the study within twelve months from the date of the final order in this proceeding. This timeline should allow the new rate designs to be implemented after the Company's new Customer Connect billing system is ready to support any proposed changes.

This concludes the summary of my pre-filed rebuttal testimony.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1214

In the Matter of: Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	))))))))	**DUKE ENERGY CAROLINAS, LLC'S CORRECTIONS TO REBUTTAL TESTIMONY OF LON HUBER**

CORRECTIONS TO REBUTTAL TESTIMONY OF LON HUBER

PAGE 6, LINES 16 AND 17 SHOULD READ:	REASON FOR CHANGE:
A. Given the considerations noted previously, the Company proposes to complete the comprehensive rate design study ~~by the end of the second quarter of 2021~~within 12 months of the issuance of the final order in this case.	Duke Energy Carolinas initially proposed to complete the comprehensive rate design study by the end of the second quarter of 2021, which would have given the Company a year to engage stakeholders and complete the study had the hearing proceeded as originally scheduled. In light of the delays caused by the unprecedented events of 2020, the Company proposes to complete the study within twelve months from the date of the final order in this proceeding.

MS. JAGANNATHAN: The panel is now available for cross examination.

CHAIR MITCHELL: All right. Public Staff, you're up.

CROSS EXAMINATION BY MS. DOWNEY:

Q. Good afternoon to the panel. My name is Dianna Downey with the Public Staff. With me this afternoon is Lucy Edmondson. I will be directing my questions to Ms. Hager, and Ms. Edmondson will be directing questions to Mr. Pirro. Mr. Huber, you're going to be off the hook from us for this time.

Ms. Hager, I want to turn to your rebuttal testimony. Specifically, on page 5, you refer to the National Association of Regulatory Utility Commissioners, known as NARUC; electric utility cost allocation manual, and you refer to it as a CAM, I believe, correct?

A. (Janice Hager) That's correct.

Q. And do you agree that that manual was produced in 1992; isn't that right?

A. I do.

Q. Have you heard of the electric cost allocation manual published in January of this year by the Regulatory Assistance Project, or RAP?

A. I have.

Q. What's your familiarity with it?

A. I have -- it was referenced by witness Wallach in his testimony the past year or so, and I have reviewed it and spent a little time with it. I'm certainly no expert on it, but I have spent some time with it.

Q. Understood.

MS. DOWNEY: Chair Mitchell, I would like to mark Public Staff 41 as Public Staff Pirro/Hager Cross Examination Exhibit 1. And this is the manual we were just discussing.

CHAIR MITCHELL: All right. Bear with me one moment, Ms. Downey, while I access the document. The document will be marked Public Staff Hager Cross Exhibit 1.

MS. DOWNEY: And, Chair Mitchell, I think we're marking these Pirro/Hager since --

CHAIR MITCHELL: Okay.

MS. DOWNEY: -- we're addressing these to the panel.

CHAIR MITCHELL: All right. The document will be marked Public Staff Pirro/Hager Cross Exhibit Number 1.

(Public Staff Pirro/Hager Cross Examination Exhibit Number 1 was marked for identification.)

Q. Ms. Hager, do you have that in front of you?

A. I do.

Q. And I just have one question about this.

Would you agree that it's fair to say that the authors of this manual suggest a different approach to aspects of cost of service allocation than the approach used in the CAM?

A. They do suggest a number of different approaches from what's used in the CAM. Oftentimes, intervenors will suggest different approaches. In this case, the manual which is put out by the Regulatory Assistance Project comes from a very specific viewpoint of wanting to encourage energy efficiency and distributed energy resources. And therefore, the manual is definitely -- favors policies and methods that would drive that.

Q. Understood. In your rebuttal testimony on page 23 -- do you have that in front of you?

A. Just -- give me just a second.

Q. Sure.

(Pause.)

A. Okay. I have it.

Q. And I'm specifically referring to your discussion and your response to Mr. James McLawhorn's recommendation that the Commission direct the Company to study the allocation of grid improvement plan investments.

In your response, as I read it, is that any allocation based on perceived benefits realized by customers is likely to be very subjective and controversial.

Did I state that correctly?

A. Absolutely.

Q. Acknowledging that there is -- there are differences in opinions on this issue, what's the harm in a study that could potentially resolve or at least result in a better understanding of this issue?

A. I just don't believe that it is an effort that's likely to yield fruit. And I think the concept of allocated costs based on benefits is -- has so many downfalls that to go forward with it would simply, I think, actually just be a waste of time. If you'll allow me, I'll talk a little bit about why I think that. The --

Q. I think I'm just asking you what's the harm in a study?

A. Uh-huh. And I think --

Q. Just talk about it.

A. So I believe -- as I said, I think the harm in a study is I don't believe it would produce anything that would be useful for the purposes of cost of service. I do think there's a place for looking at benefits, and that's how the Company has done it in this case, which is in deciding what -- you know, what projects to pursue and what -- you know, how to prioritize those projects. I think where -- to try to allocate costs based on benefits is, first of all, very much a departure from traditional cost allocation methodologies.

It is -- if you think about what we do in cost of service, we essentially look at -- you know, we have generation transmission distribution customer costs, and then we're looking at how customers use that electricity. You know, what their actual load is. And then we say, okay, how did that load cause costs? We don't look beyond the meter to say what benefits those customers receive. I think if you start doing that, I think there's a real question of, you know, where do you stop? How do you measure those benefits?

You know, I think we'd all agree what we've heard in this hearing is that there's a lot of different opinions on what those benefits would be. I would suggest they change frequently. I think they would be lots and lots of different arguments on how to quantify those. And I also think, if you think about what Mr. Oliver talked about in his testimony, you know, he made pretty clear that the grid improvement program is a program that addresses a lot of things. You know, it's designed to address the megatrends. And it happens -- as he would say it, it happens to be a program that also provides some reliability benefits, and those benefits happen to be something that can be most easily quantified for industrial and commercial industrial customers.

And that's not to say that there aren't benefits for residential customers. They're just more difficult to quantify. And there -- it's -- it's -- benefits are convenient for the purposes of selecting projects, but I would suggest that they really don't have a place for the purposes of cost of service.

Q. I think you just made my point, so I'll just move on.

MS. JAGANNATHAN: I'd like to mark

another exhibit, please. Chair Mitchell, I'd like to mark Public Staff 37 as Public Staff Pirro/Hager Cross Examination 2.

CHAIR MITCHELL: All right. The document will be so marked.

(Public Staff Pirro/Hager Cross Examination Exhibit Number 2 was marked for identification.)

Q. Ms. Hager, are you there?

A. I am.

Q. Can we agree this is the settlement agreement between the Company and CIGFUR III?

A. It is.

Q. Are you familiar with this document?

A. Yes.

Q. Let's look at page 4, paragraph 3B.

A. Okay. I'm there.

Q. So, in this paragraph, the Company agreed it will propose to allocate GIP costs consistent with distribution allocation methodologies proposed in this docket in the next rate case.

Did I represent that correctly?

A. Yes.

Q. Now, do you know what the current

distribution allocation methodologies would result, and what percentage of GIP costs being charged to residential and small general service customers?

A. I do not.

Q. Would it surprise you to know that, under the current distribution allocation methodologies, that 64 percent would allocated to residential customers?

A. That wouldn't be surprising.

Q. And that 10 percent would be allocated to OBT large commercial and industrial customers?

A. That's probably a number I would be less familiar with, in terms of the percentage.

Q. Do you think it would be smaller than that, or much different from what I just represented to you?

A. I don't have any reason to believe it would be much different.

Q. Okay. Thank you. Let's turn to the same stipulation, 5A.

A. I'm there.

Q. Okay. Thank you. And in this paragraph, the parties agreed to meet to discuss potential cost of service methodologies, and also requires the Company to file the results of a class cost of service study with production and transmission costs allocated on the basis of summer/winter coincident peak method, and consider such results for the sole purpose of proportionment of the change in revenue to the customer classes.

Did I read that correctly?

A. Yes, you did.

Q. Isn't it true that the use of a summer/winter coincident peak would, relative to summer coincident peak, allocate more production and transmission costs to lower load factor customers, such as residential customers, and fewer costs to higher load factor customers?

A. Yes, that's correct.

Q. And finally, let's look at 5B on page 5.

A. I'm there.

Q. In this provision, the customer -- it requires the Company to adjust its peak demand to remove curtailable nonfirm load, even if it doesn't call it; is that right?

A. That's correct.

Q. Now, during the test year in this case, the Company did not the activate DSM during either the system summer or winter peak, right?

A. I don't recall.

Q. Do you have any reason to doubt that?

A. No.

Q. If that's the fact -- if that's true, isn't it also true that if they didn't -- if you did not, there was no impact of DSM on the cost allocation factors in this case?

A. Let me think about that a moment.

Q. Okay.

A. Would you restate the question, please?

Q. Sure. Let's assume that Duke did not activate DSM during either the system summer or winter peak, okay? If that's the case, then there would be no impact to DSM on cost allocation factors in this case.

A. I believe that's correct.

Q. Thank you. Similarly, it's my understanding that the Company did not call on their curtailable customers to curtail either at the system summer or winter peak; is that right?

A. Again, I would not know, but I will take your word for it.

Q. Okay. Thank you. It's what Mr. Floyd told me.

If that's the case, and by not doing so, then there was no impact of curtailable load on the cost allocation factors in this case, right?

A. That's definitely true for the test year cost of service. I don't recall that any adjustments were made.

Q. Okay. Isn't it true that adjusting peak demand as agreed upon in this provision with CIGFUR would result in reducing the amount of production plant allocated to industrial; i.e., high load factor customers, and increase the amount allocated to residential and commercial customers, that is low-load factor customers?

A. The -- I can't say definitively right now. The -- the settlement speaks to curtailable/nonfirm load, but it doesn't specify specifically which curtailable nonfirm load. But to the extent that residential curtailable load was included in that, I believe that the residential curtailable load is probably lower than the industrial -- commercial industrial curtailable load. And if that is the case, then it would result in cost -- more costs being allocated away from commercial industrial.

Q. Thank you. Ms. Edmondson will now question Mr. Pirro. Thank you, Ms. Hager.

CHAIR MITCHELL: All right. Before you

begin, Ms. Edmondson, we've come to the end of the day, so we will go off the record. And just as a reminder, we will be back on tomorrow morning at 8:30. Please don't forget to join -- the line will be open beginning at 8:00. Join us as early as you are able to. Thank you.

(The hearing was adjourned at 4:31 p.m. and set to reconvene at 8:30 a.m. on Friday, September 4, 2020.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appear in the foregoing hearing were duly affirmed; that the testimony of said witnesses were taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 7th day of September, 2020.

JOANN BUNZE, RPR
Notary Public #200707300112