OFFICIAL COPY

Jul 29 2019

PLACE: Dobbs Building

Raleigh, North Carolina

DATE: Thursday, July 18, 2019

DOCKET NO.: E-100, Sub 158

TIME IN SESSION: 11:05 A.M. TO 5:25 P.M.

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Generic Electric

Biennial Determination of Avoided Cost

Rates for Electric Utility Purchases

from Qualifying Facilities - 2018

Volume 6

OFFICIAL COPY

Jul 29 2019

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

FOR DUKE ENERGY CAROLINAS, LLC
AND DUKE ENERGY PROGRESS, LLC:
Kendrick Fentress, Esq.
Duke Energy Corporation
Associate General Counsel
410 S. Wilmington Street
Raleigh, North Carolina 27602

E. Brett Breitschwerdt, Esq.
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601

FOR DOMINION ENERGY NORTH CAROLINA:
Mary Lynne Grigg, Esq.
Nick Dantonio, Esq.
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601

OFFICIAL COPY

Jul 29 2019

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

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Benjamin Smith, Esq.
Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY:

Lauren Bowen, Esq.
Senior Attorney
Maia Hutt, Esq.
Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE and ECOPLEXUS, INC.:

Karen M. Kemerait, Esq.
Fox Rothschild, LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

OFFICIAL COPY

Jul 29 2019

A P P E A R A N C E S (Cont'd.)

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE:
Steven Levitas, Esq.
Kilpatrick Townsend
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR NORTH CAROLINA SMALL HYDRO GROUP:
Deborah Ross, Esq.
Fox Rothschild, LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR CUBE YADKIN GENERATION:
Ben Snowden, Esq.
Kilpatrick Townsend & Stockton
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

OFFICIAL COPY

Jul 29 2019

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

FOR NC WARN:

Kristen Wills, Esq.
2812 Hillsborough Road
Durham, North Carolina 27705

Matthew D. Quinn, Esq.
Lewis & Roberts, PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:

Robert F. Page, Esq.
Crisp & Page
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

OFFICIAL COPY Jul 29 2019

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

FOR THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER AFFECTING THE PUBLIC INTEREST:

Jennifer Harrod, Esq.
Special Deputy Attorney General
Teresa Townsend, Esq.
Special Deputy Attorney General
Office of the North Carolina Attorney General
114 West Edenton Street
Raleigh, North Carolina 27603

FOR THE USING AND CONSUMING PUBLIC:

Tim Dodge, Esq.
Layla Cummings, Esq.
Lucy Edmondson, Esq.
Heather Fennell, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

OFFICIAL COPY

Jul 29 2019

TABLE OF CONTENTS

EXAMINATIONS

OFFICIAL COPY

Jul 29 2019

E X A M I N A T I O N S (Cont'd.)

OFFICIAL COPY

Jul 29 2019

E X A M I N A T I O N S (Cont'd.)

OFFICIAL COPY

Jul 29 2019

EXHIBITS

OFFICIAL COPY

Jul 29 2019

P R O C E E D I N G S

CHAIR MITCHELL: Good morning. Let's go on the record. Duke, please call your witness.

MR. BREITSCHWERDT: Thank you, Chair Mitchell. The Company recalls Mr. Nick Wintermantel to the stand.

NICK WINTERMANTEL; Having been previously sworn,
Testified as follows:

CHAIR MITCHELL: Good morning, Mr. Wintermantel. I'll remind you that you remain under oath.

THE WITNESS: Good morning. I understand.

MR. BREITSCHWERDT: Thank you, Chair Mitchell.

REDIRECT EXAMINATION BY MR. BREITSCHWERDT:

Q Good morning, Mr. Wintermantel.

A Good morning.

Q So I think as we briefly discussed, the Commission has called you back to ask specific questions. They've allowed some leniency for myself to ask two questions, kind of as direct questions to you, and then they're going to ask their questions. Then Mr. Kirby is going to come up, and then you'll return to the stand to answer any further questions the Commission has.

So with that procedural presentation out of the way, the first question, based on your -- you were in the hearing room --

COMMISSIONER GRAY: Pull that microphone, Mr. Breitschwerdt.

MR. BREITSCHWERDT: Yes, sir. I'm going to get better at this at some point. Apologies.

COMMISSIONER GRAY: Thank you.

Q You were in the hearing room yesterday all day, correct?

A That's correct.

Q And you heard Mr. Kirby's testimony?

A Yes, I did.

Q And I think one of the significant issues in his testimony that was discussed was the LOLE FLEX metric and this -- the 0.1 metric that you specifically used in the study. And could you please articulate for the Commission why you think the 0.1 LOLE FLEX metric is not overly conservative and how you tried to demonstrate that in your rebuttal testimony?

A Yes, I will. So the basic premise is -- Mr. Kirby is making is that the LOLE FLEX metric of 0.1 is too stringent, as -- as counsel said. So from my standpoint, my company's standpoint, our modeling framework standpoint, that argument is just fundamentally flawed, and I'll go through several steps of why that is

OFFICIAL COPY

Jul 29 2019

fundamentally flawed. But -- but backing up just -- just to some basic things that we've learned in the last two days, first of all, LOLE FLEX, we've all agreed, Mr. Kirby has agreed, does not capture or measure NERC balancing imbalances standards. They're not equal. 0.1 FLEX violations does not equal a NERC frequency imbalance. And we stated we're not going to capture NERC frequency imbalances because the models are -- infeasibly, they are not -- it's an infeasible effort. You have to have every balancing area modeled, understand the frequency in every second, and so it's infeasible. So it's just critical to understand that we have never said -- our study even had a section in it that said this does not equal the NERC standards. As Commissioner Clodfelter asked yesterday, all modelers really are having to try to create a surrogate that's correlated to those NERC standards.

That aside, Mr. Kirby's next stance is that 0.1 LOLE FLEX is way below what is allowed by NERC and imbalances. We just said, and we all agree, those -- those are uncomparable. They are not equal. So he goes on to say it's 10,000 times more stringent than it needs to be, and so -- but that's just the premise. So it's a fundamentally flawed argument because we've all agreed we

OFFICIAL COPY

Jul 29 2019

OFFICIAL COPY

Jul 29 2019

can't compare those two numbers. So to just look at that on face, it's a bad argument.

All right. So I'm going to back up now. If the LOLE FLEX was too stringent by 10,000 times, the operating reserves in DEC -- I'm going to go back to the numbers just because I think they're -- they're very important. We're adding 840 MW of solar. We're only saying that solar is causing 26 MW of additional load following, and that costs $1.10. So the volume is 26 MW on 840, it's $1.10 per MWh charge. For DEP it's 2,950 MW of solar. You would expect significantly more operating reserves compared to the DEC at 840. And so we're adding 166. That's what the model, the metric, is telling us. Again, the cost of that is $2.39. We have extensively -- and I haven't seen the Intervenors bring up a study that says the results of the study are 10,000 times worse.

The LOLE FLEX characterization of Mr. Kirby is deeply flawed. He does not understand the modeling framework that we are using. It's a surrogate. In addition, the LOLE FLEX metric has been used -- I don't want to -- I can't name all the states, but in jurisdictions across the country with high renewable penetration, New Mexico, California, they actually have published reports using the metric. This is the first

OFFICIAL COPY

Jul 29 2019

time it's ever been characterized as 10,000 times more than the NERC standard.

Further, we've gone through extensive -- extensive benchmarking as part of this process with Public Staff internally, and as discussed by Commissioner Clodfelter, your question yesterday, why do the operating reserves in the model that result in a 0.1 FLEX represent history? Well, it makes sense because the 0.1 FLEX is simply a surrogate to the standard. In 2015 we had those level of operating reserves. Was DEC and DEP meeting NERC standards? Yes. Well, in our model, we would expect more imbalances in our model in 2015 if we were -- if we were to run that with those operating reserves. So now when we -- we're calibrating, and so now in the model run, because 0.1 equaled FLEX then, then it would also assume that the NERC imbalances would be similar. So NERC imbalances are always going to be greater than 0.1.

So the fact that the historical operating reserves result in this 0.1 FLEX just proves that we're not exaggerating. So, for instance, let's just say, rough numbers here, that DEC and DEP in the model, just kind of looking at 60-minute ramping capability, is 1,600 MW historically. If we were showing that -- if the FLEX metric required 10,000 times more, then we would be well

OFFICIAL COPY

Jul 29 2019

above that, and the results and the comparisons just don't show that. So we've benched -- benched thoroughly. Our results line up with others. And so his mischaracterization is just deeply flawed. We -- we can't further disagree with him on that point -- on that LOLE FLEX piece.

And so I -- I do think, though, there were some -- some significant successes over the last two days. I think we've trimmed it down to really, in my mind, two issues. And this was the -- the one I just hit on for the last couple of minutes is -- is the major point, that it's not too stringent. I think there's another minor point, but I'm going to leave it at that. So that's the -- the reason that we strongly disagree that the LOLE FLEX metric is not producing results that are 10,000 times stringent than another metric.

Q Thank you. And the other point that we discussed, and you felt that it was important to share with the Commission, was the discussion yesterday about intra-hour volatility and why the intra-hour volatility that's used in the study you feel is appropriate --

A Yeah.

Q -- at least with respect to transmission.

A And we responded to this, kind of the same

OFFICIAL COPY

Jul 29 2019

response in rebuttal -- or direct rebuttal and the initial reply comments, but I'm just trying to understand. So the premise of Mr. Kirby is he took data from 2016 to -- it might have been '17 and '18. It's in that time frame of historical data that we had. The Companies have small solar projects in that data set. During that period, so from the start to the beginning of that year and a half or two-year period, he analyzed the diversity benefit -- benefit of that, and there was a -- a trend.

Now, we disagree with his analysis on that. We do find a similar trend, but it's a lot less exaggerated than -- than the percentage. But that's not really my point here because, yeah, there's going to be some -- some diversity across the same solar, but to get to that level in 2018 to the existing plus transition, the Company expects a very different class of solar resources. They don't expect these small resources. They're expecting large blocks of solar to come on. So we were very hesitant to put in additional diversity benefit, knowing that the class of resources is going to change. We just don't know how that's going to materialize from going from kind of the 2018 level to the existing plus transition level that was studied. We

OFFICIAL COPY

Jul 29 2019

don't know how that's going to materialize, and so really, the best way and the most appropriate way to manage that is to the run the biennial study. We're going to get fresh data the next two years. It goes in the study. We'll get how exactly that intra-hour volatility materializes.

So while this one is a -- it's more of a rational argument, whereas I think the LOLE FLEX is just a complete mischaracterization and misunderstanding, this one is a data driven difference, but I believe -- I fully support our recommendation that as the two years, you actually get that diversity benefit and that taking the '16 to '18 data and assuming the same solar is going to come on, when we know, in fact, it's not, is not the right -- right approach. It's very aggressive in trying to assume that the diversity benefit is going to increase. And I would suggest -- you know, in reply comments we go into the math, the details. You know, it's page 106 and 107 in our reply comments. Happy to go there if you have questions more about the math on that side. I don't want to get into the weeds.

But those are what I feel, based on the past two days, are still the two remaining issues. And you guys may disagree with what you've heard, but that's --

OFFICIAL COPY

Jul 29 2019

that's my take of trying to consolidate -- or trying to reconcile the difference. And both of those points were part of Public Staff's initial concerns, but partly because they -- you know, they had the ability to read the Intervenor's comments, and so that's when they had those concerns. And so we -- we addressed those with additional data requests and sensitivities to get them comfortable that the LOLE FLEX metric, as used in other jurisdictions, is not out of balance, and it really is back to the high level of the results. The results are not extreme.

If other studies were showing -- if we were showing 10, $12.00, something much higher than what we see in these studies, which range from -- you know, $1.00 to $4.00 is generally what we see. In fact, I think we brought up yesterday -- the Companies brought up yesterday a recently filed study. I mean, this was done this year by Navigant. You know, they're -- Navigant is a well known consulting firm, and they performed the study for Dominion in South Carolina, and we're -- we're well below those -- those dollars, so we can't be 10,000 times more stringent.

MR. BREITSCHWERDT: Those are my two questions.

THE WITNESS: Thanks.

OFFICIAL COPY

Jul 29 2019

CHAIRMAN MITCHELL: Does anyone have questions on Mr. Breitschwerdt's questions?

MR. SMITH: I do, just a couple.

RECROSS EXAMINATION BY MR. SMITH:

Q Mr. Wintermantel, you said that the -- and please correct me if I'm mischaracterizing what you said, but I believe you said the model here is a surrogate correlated to the NERC underlying statistical models, but they can't be compared; is that correct?

A Yeah. Absolutely correct.

Q Okay. What troubles me is the word "surrogate" and then saying they're incomparable, because a surrogate theoretically would be some sort of replacement. Can you explain what you meant by that?

A Maybe a better word is correlated. So when we increase operating reserves, we are going to lower NERC imbalances. When we increase operating reserves, we're also going to lower LOLE FLEX. They are correlated. And so they're correlated, but they can't be compared on a -- on a nominal value basis because we can't capture those imbalances. We are modeling in our model 5-minute time steps. The model has perfect foresight. NERC standards were designed for operators who have -- do not have perfect foresight. Second-to-second, minute-to-minute

OFFICIAL COPY

Jul 29 2019

operations they have -- they have forecast, but our model has perfect foresight looking five minutes out. It would not be reasonable to assume 100 FLEX violations if we have perfect foresight five minutes out. The model is able to redispatch and make decisions that operators, they just don't have that luxury.

Q Thank you. So talking about that correlation, did you validate the numbers in your model against the numbers that would reflect in the historical years against NERC standards?

A Yes. So what we've done, and this is the most appropriate way to do it, is we looked at historical operating reserves for the Companies and looked at the level of those operating reserves, and we've input that into SERVM. And when we input that, it produces an LOLE FLEX of 0.1. So we are not out of line. We are not showing load following reserves several hundred MW of what the Companies have actually operated. So that is our best guess at meeting NERC standards, is based on how we've operated historically. And so since those match, absolutely, in our model we feel like we are in NERC compliance and the 0.1 FLEX metric gets us there. And when we add our solar, we're at 0.1, we still have those imbalances. They're not shown in the model because we

OFFICIAL COPY

Jul 29 2019

can't capture them, but we assume implicitly that they are because we've benched the operating reserve inputs. So to Mr. Kirby's point over and over, 10,000 times, we would have vastly more operating reserves than what we have seen in history.

Q And when you're talking about history, you're just talking about year 2015, correct?

A I am talking about 2015.

Q Okay. Not any other years?

A Well, it's not evidence in this hearing, but I did get my staff to run some values last night on 2018. The operating reserves were higher, so we're certainly below those as well. I don't know how that works in this procedure, but to the extent -- if you're trying to argue that it's going to really matter that much from '15 to '16 to '17, what we saw in the load following calculations that we did were that we saw about -- an increase between '15 and '18 of -- it was a couple hundred MW or whatever over the two balancing areas. So it in no way says that our model runs are -- are going to be much higher than what we've seen historically.

Q Thank you. You also said -- and, again, correct me if I'm wrong -- that the -- Mr. Kirby's 2016 to 2018 data assumptions regarding to geographic

OFFICIAL COPY
Jul 29 2019

changes --
A Yeah.
Q -- are wrong, correct?
A That's right. So he took the '16 to '18 data, which are in my reply comments, and he just applied a simplified formula. Now, granted, academically, assuming -- and I don't want to get this wrong because I'm not an expert, but that in this piece of his calculation -- but basically he's taking two uncorrelated solar projects and assuming that they're -- they're completely uncorrelated and taking the variability of that and calculating that. He used the square root -- if we go to my reply comments, if we can. Do you have my reply comments?
Q I don't -- I don't have them in front of me. I can grab them.
A That's okay. No, no, no. You don't have to go there. But -- but he uses a simplified square root formula that does not, in our opinion, fit the curve, which he provided monthly standard deviations as a function of solar capacity. We plot that in our reply comments. And what you see in the diversity is that the first 400, 800 MW -- you'll see this in the curve in the reply comments -- you get this huge amount of diversity, but -- and we see this in other jurisdictions. We've

OFFICIAL COPY

Jul 29 2019

done lots of work in California, which is much larger, and that diversity benefit really -- it's really exponential, so really it's a lot early on, so kind of in that 800 MW range which we already had raw data for, and then it really flattens out. And that curve shows that.

And so if we were to assume that the small solar projects that we're on right now were to make up the rest of the existing plus transition, we would strongly disagree. And that's -- and that, in itself, is wrong. But if we were to assume that, I think our analysis showed maybe a 10 percent diversity benefit versus the 40 percent shown by Mr. Kirby.

Q Thank you. The years that you just discussed for 2016 through 2018, so there's actual real historical data that you can look at, why didn't you validate against -- in your reply comments or elsewhere where you disagree with Mr. Kirby, why didn't you ever validate why you think those assumptions are wrong?

A So I'm really confused, counsel, because in our direct testimony, rebuttal testimony, and reply comments we fully -- in fact, we actually asked Mr. Kirby a data request on this -- on this assumption, and he gave us his full data set, and then we went back and formed a trend line that we thought was appropriate based on the data, and exactly discussed in my reply comments on page 106 and 107 why we disagree with his math there. Then we further say we want to wait until we see how this materializes, because we have a significant change in our solar coming. We've got small projects. We're going to get larger projects. And so I'm -- I don't quite follow the question because it's been addressed exhaustively throughout this proceeding.

Q I apologize for exhausting you. And I don't have any transparency to data requests that you made to Southern Alliance for Clean Energy, so I haven't seen that. But my point stands, is that Duke has historical data for 2016, 2017, and 2018, regardless of what Mr. Kirby said, so why not use that data rather than comparing it against Mr. Kirby's model?

A So let me back up just to process here. So we started in fourth quarter 2017. The best data we had was the year prior. So the data and the model is based on fourth quarter 2016 through third quarter 2017, so a one-year data set. Mr. Kirby's argument was, hey, we've got more diversity benefit in our solar, so he requested '17 or '18 -- '17 and '18 data, after the study has been performed. Part of the data request he requested '17, '18 data. He did his math on what the diversity benefit

OFFICIAL COPY

Jul 29 2019

OFFICIAL COPY
Jul 29 2019

was after the data we had for the study. And so he's trying to project what the diversity is going to be to get to the existing plus transition. It's a fair, valid question/assumption. We were happy to give him the data. But then we wanted to know how he came up with a 40 percent discount, so we requested his analysis on it, which provides in Excel detailed calculations of standard deviation among the solar fleet. And so we addressed those in our -- in our reply comments, so you -- NCSEA receives those, though, right?

Q Yes, we do. Thank you.

MR. SMITH: No further questions.

MS. BOWEN: I'll try to keep them very short.

RECROSS EXAMINATION BY MS. BOWEN:

Q Mr. Wintermantel, I think we're all in agreement that nobody is modeling the NERC standards exactly.

A That's right.

Q Do I have that right? So the question is, are we getting close enough to be reasonable to the NERC standards? Would you agree with that?

A That is the question, and I would agree we definitely are.

Q Okay. Great. And you have -- you're using

OFFICIAL COPY

Jul 29 2019

this LOLE FLEX metric that you've referen--- that we've all -- we all are now --
A Right.
Q -- I think --
A Nobody wants to talk about --
Q -- more than familiar --
A -- LOLE FLEX again.
Q Ever again. But you -- you're just starting to use it. You mentioned a couple proceedings, New Mexico, California, and here, but it's relatively new in terms of using it in this context; do I have that right?
A It's been developed since -- I'm trying to remember the first day -- but the last five to 10 years is when it's been developed. And a lot of the renewable integration models have been enhanced during that time period, obviously, for -- for the reasons that we're here.
Q And for the reliability metric that we're talking about, used in that context, what's the time frame? Fairly recently.
A Yeah. I would say during that time frame that that metric has been developed, yeah.
Q And -- and there were some questions -- just making sure we understand, there's LOLE FLEX and then

OFFICIAL COPY

Jul 29 2019

there's also the underlying production cost modeling, the SERVM.

A That's right.

Q And that has been around for a very long time?

A That's right.

Q And has been vetted for years, and that's --

A That's right.

Q Okay. And then let's see, my only other question, I think, is -- well, two questions. One is, are you familiar with the Stipulation filed by Duke Energy and Public Staff in this proceeding regarding the integration charge?

A I am familiar to the extent that it includes the modeling cap --

Q Uh-huh.

A -- that details around the rates. I do know that they used existing plus transition, so somewhat, but I'll tell you if I'm not familiar with a certain question.

Q Okay. Great. And I'm sorry if I talked over you. So subject to check, if you need to, but you would agree that the Stipulation filed, in addition to setting forth the rates and the caps, also says that the Stipulating Parties agree that Astrapé study data,

OFFICIAL COPY

Jul 29 2019

methodology, results, conclusions are reasonable for the purposes of quantifying these charges?

A That's correct.

Q Okay. So it's important to make sure that we are getting this right because we're talking about this for years in the future, not just this proceeding?

A Yeah.

Q And then I think my last question is just -- I know you mentioned that in comparison to other studies, that the dollar per MW hour results seem in line with those, but -- and I don't want to spend a lot of time on this at all, but just very quickly, we did look at a chart where when you're looking at the extreme, are you talking about a lot of penetration, a lot of solar coming online. And I realize that you're not seeking those charges at that time, but when you're looking out that far, we do see -- we saw -- we all saw that upward trend line.

A Yeah.

Q Would you agree with that? Okay.

A No. I understand. Yeah. That --

Q Okay.

A That was in the study. Again, I just want to reiterate it was written in the original report. The

OFFICIAL COPY

Jul 29 2019

high levels are highly uncertain. There's likely to be changes in the resource mix. We're going to be able to address the additional intra-hour volatility as it comes, so by the time you get there, you're going to get -- get better assumptions, but ultimately, solar causes intermittency, and the system is going to have to figure out the best way to -- to address it and whether, currently, at these low levels -- not low levels, sorry -- at these levels there's operating reserves available on the -- in the resource mix to accommodate that. Ultimately, as you go higher and higher, you're going to be at a point to where you're having to use more expensive resources to do that. So you wouldn't expect an exponential curve, but hopefully through resource mix changes, whether it's storage or whether it's -- or the diversity benefit that we see as to where the solar is placed, you would hope that those exponential curves decrease.

MS. BOWEN: That's all I have at this time. Thank you.

MR. LEVITAS: And, Mr. Wintermantel, I just have one quick question regarding the Navigant study you mentioned.

THE WITNESS: Sure.

OFFICIAL COPY

Jul 29 2019

RECROSS EXAMINATION BY MR. LEVITAS:

Q Are you aware that that study and its results and recommendations have not, at this point in time, been accepted by the South Carolina Public Service Commission?

A Yes. I'm aware of that.

Q And you're aware that they are going to have, at some point, a proceeding similar to this one in which they determine whether those results are accurate and reliable and appropriate for imposing an integration charge?

A Sure. Yeah. The only point of my -- of us bringing that up is just another consultant firm doing a similar analysis on a neighboring utility produced results and, actually, for whatever reason, there could be differences, but it produced substantially higher results than what we're trying to bring here, when it is being characterized that we're bringing in a result that's 10,000 times too stringent for the balancing areas.

MR. LEVITAS: That's all I have. Thank you.

CHAIRMAN MITCHELL: Questions from the Commi--- Mr. Dodge?

MR. DODGE: (Shakes head negatively.)

CHAIRMAN MITCHELL: Questions from the

OFFICIAL COPY

Jul 29 2019

Commission?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Wintermantel, good morning.

A Good morning.

Q Thank you. That's helpful. And I'm going to -- let me say thank you especially for what I want to focus on, is your distinction between the correlation of your -- the results of your model and the NERC reliability standards --

A Yeah.

Q -- as opposed to being a surrogate. And I -- I thank you for that. And I think that's a very, very important distinction in concepts conceptually. And I may be the one who confused this yesterday by using the word surrogate in some of my questioning of Mr. Kirby, but stay with me for a minute on this.

I'm going to present to you a thesis, and then I want to explore it with you with some questions. And the thesis is this, is that you are not using a different metric to try to model for reliability. You're actually trying to solve for a different thing than reliability. That's the thesis. That thing that you're trying to solve for in your model is, in your view, correlated to NERC reliability, but you're not trying to solve for NERC

OFFICIAL COPY

Jul 29 2019

reliability; you're solving for a different variable altogether. And that's what I want to explore with you through some questions, okay?

A Okay.

Q Okay. Keep the thesis in mind, and we'll come back and see if -- if I've got it correctly, because really the point I want to get at is have I understood it correctly, okay, what's going on here. So it struck me yesterday, and I hadn't paid enough attention to it, is the condition in your model is that the system operator has perfect knowledge on a 5-minute forward basis of net load. That's the condition of your model.

A That's -- that's correct.

Q Okay. So I had to think a little bit about what does that condition mean, and tell me if I've got it right and understanding. My question to you is, am I understanding it correctly? It means that a system operator in your model can look five minutes ahead and has no load uncertainty, no solar variability uncertainty because he knows the net load, the system operator knows net load and, therefore, can fully plan to meet reliability through his dispatchable resources and his resource stack and through his knowledge of his non-firm resources that are available to him throughout the

OFFICIAL COPY

Jul 29 2019

interconnection. He -- he has the ability to meet NERC standards. He's not concerned about the NERC reliability standards because he knows exactly what he's got to manage to, right?

A That's correct.

Q So he doesn't really care about NERC reliability standards in the premise of the model.

A That's right.

Q He knows exactly what his resource stack is, what he's got -- what his ramping capabilities are to meet a variation. He knows what's firm and he knows where he's short. He knows what his non-firm resources are. He's solved the reliability problem already. It's a premise of the model that the reliability problem is going to be solved.

A That's right. So --

Q Right.

A -- I would just add to that, that the model has got the 5-minute foresight, so in reality, we would know that there would be these crossing across and --

Q Right.

A -- having these imbalances --

Q Right.

A -- inside. That would be occurring in real

OFFICIAL COPY

Jul 29 2019

life --

Q Right.

A -- but we obviously can't capture that, and so you have to come up with a modeling metric. And Idaho, SCE&G, all these different studies do the same thing. They're coming up with some kind of reliability metric that they believe, threshold that they can model, that produces reasonable operating reserves really at the starting point in the base case, which is really the core of the benchmarking that we did that helps us assure that we're not completely out of bounds, I mean, to a degree. So we need to make sure that our operating reserves at the starting point are reasonable, based on history and times when we met NERC requirements.

Q Right. And -- and that's the correlation, is you're saying I know if my operating reserves are adequate from a resource adequacy standpoint -- from a resource adequacy standpoint, then likely I'm going to be able to operate my system and manage it, because I know I always have, to meet the NERC standards for reliability.

A And --

Q That's the correlation.

A That's right.

Q The correlation is between resource adequacy

OFFICIAL COPY

Jul 29 2019

and my known ability to manage to reliability standards. That's the correlation. Those are the two things that are correlated. So am I right that what you're really trying to solve for in your model is a type of resource adequacy approach to the question before us? That's why you're using a loss of load metric; is that right?

A That's right. That's right. We're measuring the ability of the system to have enough ramping capability. And so if you don't have enough ramping capability -- it really goes back to my -- my response earlier, that the correlation -- if we increase operating reserves, we know that we're going to also decrease NERC imbalances. We're also going to decrease LOLE FLEX. The tying of 0.1 to the 100 allowed imbalances is just really confused and tried to mischaracterize, but --

Q I don't mean to cut you off, but I -- I get it.

A Okay.

Q Thank you. So, again, in my -- in my thesis -- in my thesis you've chosen to solve a -- solve a reliability issue by looking at a correlated concept, which is resource adequacy, and solve for that. Is that what you did in the model?

A That is -- that's correct, what's happening. And maybe we could have better explained that in the

OFFICIAL COPY

Jul 29 2019

study, but sometimes you need this back and forth to really --

Q I sure need it.

A -- to really get there. Because in the modeler's mind, we're in it every day, we see the results, we're seeing the runs, we see the operating reserves, we see all this, and it -- it's just sometimes difficult to explain it to someone who is not in that every day. And so I think this back -- I mean, this is -- this is really good.

Q So -- so your model -- your model says -- the problem statement says that if I can ensure that based upon a capa--- resource capacity analysis I have sufficient operating reserves in my stack to match my expected demand, then I'm probably going to meet my reliability requirements?

A That's fair.

Q Now, the question, then, that -- that helps me because it means then the question -- it focuses me, then, the question I have to decide, we have to decide, is what's the strength of the correlation? How strong is that correlation? How good is that correlation? Is it good enough? Not that I use what you've done as a surrogate, because it's not. It's not. It's not that.

OFFICIAL COPY

Jul 29 2019

But how strong is that correlation? And so, again, the question is, what -- what really did you do to validate the strength of that correlation? You've told me -- you told us earlier that you checked it against the actual 2015 operating reserves maintained by the two Duke companies. Did you do anything else to measure the strength of the correlation --

A I'm trying to think.

Q -- to test it?

A I mean, that's been the main premise to this point. We also stress tested just the -- the FLEX metric itself. So we did some analysis with the Public Staff that said, okay, what if that correlation isn't perfect? But we know, and even this is quoted in the Idaho study, that the ultimate 0.1 or threshold that you're bidding at is relatively immaterial. I mean, truthfully, we -- I would even add to your thesis that the most important thing that we're trying to capture is that incremental amount of operating reserves that we need when we add the solar --

Q Yeah.

A -- but that's a little bit of a different piece.

But back up to where I was going, so we -- we

OFFICIAL COPY

Jul 29 2019

did stress test from 0.1, and we moved it all the way to tenfold because we really wanted to understand if the reliability threshold was that immaterial. And so we -- we moved it 10 times which, in my mind, is a fairly large variation of the FLEX metric. And you'll see in our -- I'm trying to think what -- it's in my rebuttal testimony, but we see that those results were very stable, the actual final results. So the amount of operating reserves we had to increase for the solar --

Q Right.

A -- and the cost associated with them were very stable across that pretty large variation of the FLEX metric. So -- and that was really just to, you know, further prove that it's -- it's not too stringent. I mean, I guess we could be arguing that we're missing it the other way, right, and that the modeled reserves could be lower than the historical which would say instead of 0.1, we really should be at .05. But I think what we're arguing is that from .05 to one, that's getting us to a reasonable level of operating reserves.

I would also add that there's a lot in historical, as you probably are fully aware. I mean, fuel forecasts, generator outages, what's available to the operator, that a year -- that they -- that they can

OFFICIAL COPY

Jul 29 2019

move around a little bit, they realized operating reserves. And so historical can move a little bit from year to year, but what I'm saying is our comparison is not that we've got 3,000 MW of operating reserves and that the actual was at 1,500. We call it 15 to 1,700 in the modeler and 15 to 1,700 as a starting point. But did it make sense about the stress testing, though, in the FLEX?

Q It did, but tell me, can you -- can you -- I don't know if you have your rebuttal testimony there. Can you -- can you point me to where I can go back and study that again?

A Yes.

Q Where in the rebuttal testimony that is so I can study it again?

A Be happy to. And then there was one other thing we -- we did, which is in the rebuttal testimony as well. Brett, do you have -- Mr. Breitschwerdt --

MR. BREITSCHWERDT: Rebuttal testimony, I do. And I can also provide you Jeff Thomas' testimony where he presents the chart. That is Exhibit C, I believe.

A So on page 14, I've got it, of my rebuttal we talk a little bit about it on row -- on line 7, but there may be another point where we actually bring it up,

OFFICIAL COPY

Jul 29 2019

because that's just comparing the discussion to the Idaho study we make on -- there should be the actual numbers in here.

Q Is there in the record the backup for the statement made there on lines 7 through 10? Is that in a data request somewhere?

A I'm trying to think. So we've provided that to Public Staff, those -- those results.

Q So perhaps I'll ask Mr. Thomas about that and he may know where in the data -- data request that is.

A Maybe that's -- maybe that's a better question. But I'm struggling here, Commissioner Clodfelter, just because I know we -- in here we -- we actually show the percentages, that it decreased, I thought, but it's in the -- it's in the record that it was a very small percentage decrease in the rate. But, yeah, that was done. And then, lastly, and this really -- I don't --

MR. BREITSCHWERDT: Chair Mitchell, may I approach?

CHAIR MITCHELL: Yes.

THE WITNESS: Did you find it?

A Okay. Yeah. So Public Staff Exhibit C.

Q Okay. Thank you.

A You can -- you can see those --

OFFICIAL COPY

Jul 29 2019

Q Thank you.

A -- those results. And one other thing we tried to do because, you know, there was a lot of argument about the Idaho study, the 90 -- invented 90 versus the invented FLEX metric. And so -- and I know -- I don't want to go into extreme details, but it is important to realize that the Idaho study is a pretty different methodology now. So while that metric might correlate well for them and work, the difference -- I'm going to go there just for a second, but that the Idaho study, the reliability threshold and model is done outside of a production cost model. So -- so they're looking at net load 5-minute volatility, just think about it in an Excel table, and they're figuring out the 5-minute deviation compared to the hourly average, and they're saying I'm going to carry this amount of operating reserves, just based on this -- this net load volatility that we do outside the production cost model.

Well, if you were to take the worst, kind of the 1 in 10, you would get a really high load following reserve requirement. So they use the 99 percent, which is 90 hours, which brings it down. And then they apply some -- outside of the model some wind and load discounts. And they just say we need these amount of

OFFICIAL COPY

Jul 29 2019

operating reserves based on that analysis done in the spreadsheet. Then they go to the production cost model and just force those in to calculate the cost. I'm not -- I don't really have a problem with that. It's just -- it explains why the 90 is probably okay for that because they're not getting the ability of what we just talked about, the ability to redispatch my resources and have this perfect knowledge to -- to avoid those violations. They're saying those violations are just there because of the 5-minute net load analysis outside of a production cost and all that.

But what we did in my rebuttal testimony to kind of further show that our operating reserve volumes weren't too much, and if you go to page 14 in my rebuttal on the second half, so starting in line 11 --

Q Right. I'm familiar with that --

A Okay.

Q I am familiar with that testimony.

A So I won't --

Q No. I've got that testimony.

A Oh, okay. Yeah. You've got it.

Q Right.

A So what we did was external to SERVM, just trying to -- why is -- why is this working and we're

OFFICIAL COPY

Jul 29 2019

getting the same results with the Idaho study? We took the 99 percentile of our 5-minute solar data, so DEC and DEP's 5-minute solar data, and figured out that for DEC, if we just take that volatility of solar, the 99 percentile would mean we need to carry 92 MW of load following and 295 for DEP. We realized -- in the Idaho study they further give these load and wind diversity benefits, so we don't -- that is some calculations they've done that aren't really shared in the study. So we had to apply those. So just -- it's not exact, but to try to replicate, we took those discounts. But that would assume that DEC and DEP actually have wind, which we -- we do not. So it probably overstates the discount, but we just applied the discount. And applied the discount, and what that showed was that using the Idaho process would require DEC to carry 23 MW versus the 26 we show, and require DEP to carry 188 MW, which is -- we showed 166. So I'm really not arguing that the Idaho study is wrong. It's a different methodology. And so their metric of 90 probably correlates well with whatever -- the way they're doing it, just like our 0.1 correlates well inside the model.

Q Okay. Let me -- thank you. Let me -- you lifted the curtain a little bit and said you'd done some

OFFICIAL COPY

Jul 29 2019

back-of-the-envelope rerun of your model to see how it compared with the historical operating reserves for year 2018. How difficult would it be to do that for 2016, 2017, and 2018, to run it again -- to run -- to run your model, hold it to the 0.1 FLEX -- LOLE FLEX result, see what reserves the model spits out, and then compare to the actuals?

A Can I clarify a little something --

Q Sure.

A -- here?

Q Yeah. Okay.

A So in the SERVM runs --

Q Right.

A -- that we've already run, so we're modeling the 2020 system and we're varying the solar. But within that base case no solar run, we've already simulated all the weather years, so I can go pull the -- I can -- I can do exactly what you're saying. So for the 0.1 aggregate metric, I can go pull already existing results, kind of what the operating reserves, the model, say total for '15, '16, '17. That's just kind of imbedded in the -- in the results. And then we can compare that -- you know, this is what we -- we don't have, which would be the actual historical -- that I don't have now kind of thing

OFFICIAL COPY

Jul 29 2019

that we would have to go and pull, which I think was a data request earlier, and we can try to make that comparison.

I mean, I would clarify a little bit just that there's -- there's a lot of nuances in this data because 10-minute ramping and 60-minute ramping -- I don't want to get into details, but you've got to make sure all that's -- that's correct for a good comparison. And so we did use a 60-minute just because that's what -- what SERVM outputs. It models the 60-minute capability for every increment, or it spits that out as the run so we could know the 60-minute. So that would be what we would compare against, which is what we did in kind of our '15 analysis. And then we've -- we've also started to look at 2018. But, yeah, we can -- I think we can get you what you need there to -- to show --

Q On the same basis --

A -- what you're trying to see.

Q -- as the 2015 --

A Yeah.

Q -- calibration as well?

A Yeah.

Q Okay.

COMMISSIONER CLODFELTER: Mr. Breitschwerdt,

OFFICIAL COPY

Jul 29 2019

how difficult would that be?

MR. BREITSCHWERDT: I have no idea, but we will investigate and get back to you either by the end of the day today or as quickly as we can.

COMMISSIONER CLODFELTER: Let me leave it in the air for now. Madam Chair, with your permission, I -- I don't want to make a data -- a late-filed exhibit request that's going to cause all sorts of consternation, so let me let Mr. Wintermantel and his counsel confer a little bit more about how -- what would be required to generate that before I make the late-filed exhibit request and maybe make it later in the proceeding. Is that acceptable?

MR. BREITSCHWERDT: We'll work on that today.

COMMISSIONER CLODFELTER: Okay. Thank you.

THE WITNESS: I think that would be helpful.

COMMISSIONER CLODFELTER: Mr. Wintermantel, thank you. That's all I have.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q Mr. Wintermantel, Astrapé prepared the resource adequacy study for Duke; is that right?

A That's -- that's correct, for 2012 and 2016.

Q And so does your work in this docket flow logically out of that, and was it consistent with it?

OFFICIAL COPY
Jul 29 2019

A Very, very much so. So the framework of the model, except for when you're thinking about reserve margin, the major differences are -- for the reserve margin you're thinking about peak capacity and it doesn't require these intra-hour simulations. So it's really taking that hourly framework and advancing it to 5-minute time steps which allows you to -- you also need to better capture the units and their ramps. So you're more concerned on the intra-hour, but yes. Yes. So the framework was directly applied.

Q So your model leverages the same dispatch capabilities as the SERVM model?

A That's right. So both of those studies utilize the SERVM dispatch commitment and dispatch engine, yes.

Q All right. And -- and so you didn't have to abandon the work that you did in the resource adequacy study to get to the results here?

A That's correct. So all the load volatility and all the underlying probabilistic assumptions are in both of these, so I think it does provide kind of a seamless transition into the results.

Q All right.

COMMISSIONER BROWN-BLAND: Thank you.

THE WITNESS: Sure.

OFFICIAL COPY

Jul 29 2019

EXAMINATION BY CHAIR MITCHELL:

Q Mr. Wintermantel, I -- I have a few questions that may result in your retreading some ground, so just bear with me --

A That's fine.

Q -- because I want to make sure I understand this -- this point. We've talked a lot over the past couple of days about the perfect foresight condition in the model. And I just want to make sure I understand the implication of that condition, and let me tell you why. You had a discussion yesterday with your counsel about the distinction, at least this is the way I understood the discussion, the distinction with the Idaho study. The Idaho study uses historical data, where your model uses that sort of perfect foresight condition. So can you -- if I have sort of incorrectly --

A Yeah.

Q -- understood that distinction, clear it up for me. And then further, explain the implications or the significance of the perfect foresight condition.

A Yeah.

Q And then one last -- one sort of last issue -- I know this is a complicated question, but I want you to talk about all these things. Help me under--- help me

OFFICIAL COPY

Jul 29 2019

understand how you get to the incremental load following reserves, because I understand from your testimony that that's really where our focus needs to be. So is there a connection between the perfect foresight condition and that increment?

A Yeah. All right. So I'll start with kind of the perfect foresight between the two studies. So SERVM, while we have perfect foresight on that next five minutes, because the model is ultimately -- we've got to meet load, right, and so there's perfect foresight on that next five minutes, but before that five minutes occurs, there's lots of uncertainties. So the model doesn't have perfect knowledge of what net load is going to be day ahead or hour ahead or even 10 minutes ahead. So there is volatility uncertainty in the model to manage all that. And I think that's a very important piece of modeling this type of analysis, if you're going to do it inside the production cost model, right, because you don't want to have perfect foreknowledge; you want to -- you want to capture -- and that's usually a very strong argument of why we model the way we do, because you don't want perfect foresight for all of this. But what we've gotten to in this docket is trying to compare 0.1 to these NERC imbalances, and so what's it's caused us,

OFFICIAL COPY

Jul 29 2019

really, to have to do is -- because this really isn't a huge point in most of our other jurisdictions, but what we've really had to do is dig in and prove that that five minutes, the next five minutes having perfect foresight is why it doesn't equal a -- a NERC imbalance, or we can't compare the two because the NERC imbalances are happening as we speak all the time. I mean, real time we're chasing load -- operator chasing load.

So -- so SERVM, we do have imperfect foresight, day ahead, we put in uncertainty around load and solar within the model. So the model commits to the wrong net load, and then we have to -- have to make it up and avoid violations, but we increase operating reserves enough and we can achieve. And that goes back to your last question which I'll come to in a minute. And I'll shift to the Idaho study. Does that -- does that clear any questions on the SERVM piece of what we're doing?

So the Idaho study, we've got just historical solar load and wind data outside of a production cost model. And what we're trying to do is calculate, really, what the uncertainty is of that data. And so we're -- they're trying to determine the number of operating reserves just based on statistical analysis of that net load data. So it's kind of a -- it's not really the

OFFICIAL COPY

Jul 29 2019

right question to even ask if there's uncertainty in that. That's just a mathematical, statistical analysis of 5-minute load, wind and solar. That determines the amount of operating reserves that they're going to assume. And they use the 90, but there's -- there's good reason to probably use that. It correlates well with -- with where they're trying to go.

And then so -- then those operating reserves get put into an hourly production cost model, a simpler approach, but fair enough. And we're just using the production cost model over here which has perfect foresight. But we're not even looking at reliability in the production cost model in Idaho. That's all done over here. We're just saying, hey, we're going to have this amount of operating reserves based on that statistical -- that load data, and then we're simply taking the operating reserves, putting it in the model, just an hourly normal production cost model. I do think they -- they were pretty granular in some of the -- some of the things they were doing, but it's hourly, and they calculate the cost of those additional reserves. And so their production cost model truthfully is perfect foresight, and they're meeting -- meeting load perfectly, but they're not trying to determine if they have

OFFICIAL COPY

Jul 29 2019

reliability problems over there. So it's okay. They're just trying to figure out what the cost is.

So it's really two very different methodologies. They use two different metrics that probably correlate well with -- with the ramping capability of the system, which is what we're measuring, and ultimately produce reasonable results in both studies that we've tried to show, compare very well.

And then your last question, you -- you're extremely right. The incremental load following reserves are really what we -- what we are solving for. So we start with a no solar model run. And so really all you need operating reserves there for generator outages, your conventional fleet generator outages, you don't have solar, and then load uncertainty. That requires "x" amount of reserves to get to -- to 0.1. And that's really what we're trying -- you know, we -- more so in this proceeding, just due to the -- the comments, but we've really had to focus on that to make sure we're not too stringent. If history said it needed to be 1,600, let's make sure that our no solar case that gets us to 0.1 isn't 2,500, 2,000, or something, something higher. So that's the starting point. So that says we need "x" amount of operating reserves to get to 0.1 in the no solar case.

And then we go to the existing plus transition case, and we're going to add 840 MW of solar in DEC. I'm going to leave my operating reserve assumptions the same in the first run. And when I add that solar intra-hour volatility in, the SERVM model is going to increase. And so now, even though I have 5-minute perfect foresight, my model is not going to commit enough operating reserves to handle some of those deviations. Now, some of those deviations will just be absorbed because we -- even in the no solar case there are shoulder hours where we had some excess operating reserves, but that -- that gets into the weeds. But we're going to -- so now, all of the sudden my 0.1, when I added that 840 MW of solar -- and these aren't exact, but let's say the 0.1 goes to 0.3, it makes sense, right? We've added this volatility. And I've maintained the same level of operating reserves so my reliability has worsened. I can't have the same reliability. And so now in my plus solar case I -- I step up operating reserves till I get back to 0.1. And that amount that I had to step up in the with solar case to go from 0.3 to 0.1, that's the volume that we need. And the cost of those are what we're saying is -- contributed to the solar in a dollar per MW rate.

OFFICIAL COPY
Jul 29 2019

OFFICIAL COPY

Jul 29 2019

Q Okay.

CHAIR MITCHELL: Thank you. That's helpful.

THE WITNESS: Okay.

FURTHER EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q One more follow up here. From what you said, am I wrong that your output encompasses the same cost that Dominion was trying to characterize?

A I mean, subject to lots of methodology changes, they're trying to capture the ancillary service cost of solar, yes. They're running a production cost model to do that. So, yes, I think they're probably -- you know, we've gotten the details, the reliability metrics. And exactly how they're doing that, I'm not as familiar with, but, yeah, ultimately the goal of the study is exactly the same.

Q And so yours includes -- you capture that.

A Capture the --

Q Capture the same cost that they were trying to?

A Yes, yes.

Q Okay.

CHAIR MITCHELL: Any additional questions by the Commission for this witness?

(No response.)

CHAIR MITCHELL: Okay. We will take questions

OFFICIAL COPY

Jul 29 2019

on the Commissioners' questions, starting --

MR. BREITSCHWERDT: Thank you, Madam Chair -- Chair Mitchell. One question.

EXAMINATION BY MR. BREITSCHWERDT:

Q So Commissioner Brown-Bland at the end asked you about -- and I just want to make sure you got it correctly, but it was the Dominion redispatch charge --

A Oh.

Q -- that she was asking about, and whether the Company's integration charge and your study --

A Okay.

Q -- quantifies the same cost.

A Yeah. Commissioner Bland, I'm sorry. I mis--- completely misunderstood your question. I thought we were bringing up the Dominion integration services cost study that we brought up yesterday from South Carolina, and I apologize. So I need to re--- readdress that question. And I'm not as familiar with the Dominion -- so it's the redispatch which is part of this docket. So the difference is -- this is very -- this is very difficult, but I'm going to do my best.

So we're capturing the -- really, we are capturing the ancillary service cost of intermittent solar. That's -- that's in our study. And that

OFFICIAL COPY

Jul 29 2019

encompasses intra-hour -- it even encompasses multi-hour ramps. It's just what we see. The system is already set up to handle the multi-hour ramps, honestly, and so what we see the driver of our ancillary service cost is to be the intra-hour. So I know it may have been said that we're not covering the multi-hour ramps, but we are. And so we're distinctly capturing how do we move our units -- how do we have to move our units down, additional ancillary services, to accommodate.

The Dominion redispatch really goes in, in my opinion, more to the -- the way that we -- it's kind of crossed over to the energy value of -- of solar. So when we add a solar resource to the system, that's going to produce an energy benefit to the model. And so my understanding, in some of the avoided cost proceedings that's done with just a base load resource to calculate avoided energy cost. So if you put in 100 MW unit in every hour of the year, we calculate the production cost benefit of that, and that's how the rate is set. Well, I think Dominion, what they're trying to recognize, that instead of putting in that 100 MW of base load, that if we actually put in the 100 MW of solar every hour, then the units are going to have to start up more frequently and redispatch, and that that's an additional cost. And

OFFICIAL COPY
Jul 29 2019

so I'm going to get -- I think that's probably as far as I can go, but I think -- I do think there probably could be additional cost if, from what I know in the Duke process, if that was included, that there would probably be slightly additional cost above our ancillary service cost if --

Q Right. And the Duke --

A -- if we were to really recalculate that redispatch, but as -- as discussed earlier, I'm still not sure -- there's probably some overlap there, so one plus one may not equal two.

Q But your thought is it could be additional cost to the Duke proposed cost?

A That's right.

Q Okay. Thank you.

A If included, too.

EXAMINATION BY MS. BOWEN:

Q I do have some questions on the Commissioners' questions. Thank you. I'm amazed that Commissioner Clodfelter managed to distill four days -- four days of testimony into one question, which is how strong is the correlation between your study and the NERC standards? And he asked you in follow up what did you do to validate the study, and you talk about -- you talked about some

OFFICIAL COPY

Jul 29 2019

stress testing. It sounded to me like that -- we've also heard the term the post-operating techniques which was referenced, I think, in Public Staff's testimony. And it sounds like those you described as those are the same, right?

A (Nods affirmatively.)

Q Okay. Yes? Okay.

A That's right. That's right.

Q That's right. Okay. And on the 10 -- using the 10 times the results metric in those -- that stress testing of the post-operating technique, what was the basis for using that 10 times number?

A There was really just no basis. We were just trying to stress test, and we figured tenfold was -- was enough to -- to move it, given that we had already felt like our operating reserves were -- at 0.1 were reasonable compared to history, that going 10 times, that would decrease our operating reserves. And we just really wanted to see how it impacted the results, though.

Q Okay. And then Commissioner Mitchell asked you about ramping capabilities and operating reserves. And the reason that we care about that is to make sure that the utility doesn't violate its reliability -- NERC reliability standards, right, to make sure they have that

OFFICIAL COPY

Jul 29 2019

capability to meet -- to meet reliability?

A I'm sorry. Can --

Q Do I have that right?

A I'm sorry. Ask me one more time.

Q Am I asking that poorly?

A Ask me one more time. I might have...

Q Sure. So in talking about ramping capability of a system, the reason we care about that is for reliability concerns, and we want to make sure that the system can keep up with intermittency --

A That's right.

Q -- and volatility.

A That's right. Yeah. We need ramping capability on our system to meet increased solar volatility, yes.

Q Okay. And if we overestimate the operating reserves needed for the ramping capability, that could result in overcompliance and overcharging for -- from what we might -- what we actually need. Do I have that right?

A Yeah. If we exaggerated the operating reserve increases, that would result in a cost, but nothing we've seen to date has shown us that we've -- we've done that.

Q Okay. And then circling back to -- to the post

OFFICIAL COPY
Jul 29 2019

-- the stress testing and post-operating techniques that you talked about with --
A Yeah.
Q -- Commissioner Clodfelter, I just -- I guess I want to ask a process question about that. So you've described what you guys did to do that, and we've referenced a lot the Idaho study. Do you have that study with you?
A Do not.
Q Okay. I'll get --
MS. BOWEN: Do you have an extra copy?
Q It's okay. You know what, I'll say how about subject to check?
A Okay.
Q Is that okay? Subject to check, we talked about yesterday the technical review committee -- let me try -- I have my -- turned around -- technical review committee process described on page VI of the report. Do you remember that?
A I think I am, yeah, familiar with that.
Q Okay. And the report does outline sort of what all is involved in that?
A Yeah.
Q Okay. And -- and presumably they would have

OFFICIAL COPY

Jul 29 2019

done some -- that review committee would have done the kind of validating or stress testing or at least looked at what you all were doing as part of that process. Is that what you would expect from a TRC?

A Yeah. I mean, if a -- yeah. That's correct.

Q Okay. And then the only other question, and subject to check if you need to, but about the Idaho Power study is that on page 3 of that study -- and just to be clear, we are talking about the April 2016 Solar Integration Report. Yeah. My colleague has got a copy if you need it. And, yeah, I can give you a minute to look at this if that's helpful. It's, yeah, page 3.

A That's strange. The top of it says 2014. I just noticed that, but...

Q Yeah. And I --

A Oh, this is the older study. Okay.

Q Yeah. I can explain. Yeah. I got it. So this -- you're right. The heading says 2014 Solar Integration Study. So page 3 of the Idaho -- again, let's make sure we're talking about the right one, Idaho Power April 2016 Solar Integration Study Report. It goes through -- it actually just -- it gives the background for the proceeding and the study and how they got to where they did in this -- in this report or this study,

OFFICIAL COPY

Jul 29 2019

and they talk about how -- and subject to check, if you need to, but how they started out with a 2014 Solar Integration Study, ended up having a Stipulation among the parties, and then requiring this technical review committee and actually laying out the factors that they needed to look at. So subject to check, if you need to, would you agree that the -- this is what the report reflects on page 3?

A I mean, I'm really not familiar with the process at all, but, yeah, I could go back and read that, and I would expect what you're saying is probably -- that that actually occurred.

Q Okay. Great. And then Commissioner Brown-Bland asked you some questions about the 2016 Astrapé resource adequacy studies. And it's my understanding, as I believe Commissioner Brown-Bland said, there is a link between the studies. So we've got a couple of different Astrapé studies, you know, the integration charge study, solar ancillary services study, and then the resource adequacy studies from 2016. Do I have that right?

A So in my mind there's -- you probably said this, but just to be clear --

Q Sure. Yeah. Absolutely.

A -- so there was a 2012 reserve margin study,

OFFICIAL COPY

Jul 29 2019

resource adequacy study, 2016 resource adequacy study, the 20--- what was finished, I guess, and filed in '18, the renewable -- the ancillary service study, and then we also filed a solar -- I'm not sure if it was filed, but we did a solar capacity value study as well last year.

Q Yeah. I think you --

A I think there's four studies, yeah.

Q Four studies, yeah. And I might have had the capacity value and the name wrong, so thank you --

A Okay.

Q -- for that. And then I know we -- we haven't talked about it a lot, and SACE Witness Wilson was excused from this proceeding because no one had cross examination for him, but would you agree that some of those other studies that you've talked about, those were the subject of -- of Mr. Wilson's testimony in this proceeding?

A Yes. I recall that Mr. Wilson -- I think I remember reading his initial comments, and they were very much basically what he said a couple years ago. And a lot of that has been addressed, I believe, between -- this Commission ordered a 100-day report between the Company, as we were kind of part of -- part of that study with the Public Staff. And so from my standpoint, those

OFFICIAL COPY

Jul 29 2019

items that Mr. Wilson has brought up have been -- have been addressed and that the next -- whenever the Company does their next reserve margin study, all those assumptions will be -- will be reviewed.

Q And -- and some of those -- the same critiques we're seeing in this proceeding are overlapping with what's now pending before the Commission in the 2018 IRP proceeding. Are you aware of that?

A Yeah. I'm -- I'm probably getting out past my --

Q Okay. That's fine.

A -- out over my skis here.

Q Yeah. Understandable. Okay. And then -- and I think I had one more question for you. That may be it.

MS. BOWEN: Okay. That's all I have. Thank you.

THE WITNESS: Okay. Thanks.

MR. LEVITAS: And I just have two or three questions following up on Commissioner Clodfelter's correlation concept.

EXAMINATION BY MR. LEVITAS:

Q So in response to Commissioner -- to Chair Mitchell, you described a situation where you modeled the base scenario, you had a point -- you comply with the 0.1

OFFICIAL COPY
Jul 29 2019

metric, you added solar, I believe it was the existing plus transition, and I don't know -- excuse me -- I don't know if this was the exact number, but you suggested that maybe that resulted in a 0.3 scenario that had to be, in your mind, corrected to bring that back into alignment with the 0.1 standard --

A Yeah.

Q -- correct?

A Something -- something higher. I'm not sure of the number.

Q Something like that, but what the model did was -- calculated the quantity of additional resources that were needed to -- to reduce the exceedances or the violations from the 0.3 back down to the 0.1, correct?

A Not added resources, but added the operating reserves.

Q Operating reserves.

A They forced --

Q I apologize.

A They forced the units to operate differently, yes.

Q Understood. And so, again, with respect to this issue of correlation, I understand that the model drives the need for additional operating reserves or the

OFFICIAL COPY

Jul 29 2019

determination of that, but do you have any basis for determining that at that 0.3 level, that excursion to 0.3, that there would be a greater number of NERC -- violations of the NERC standard? Do you have any basis for answering that question?

A That just goes against the entire premise of the study where we do not want to add solar, regardless of if the LOLE FLEX metric -- if you agree with what we said, it meets NERC standards, what that would be saying is I can add solar, and I'm going to let my balancing area have worse reliability. No matter what the threshold is, you want to get back to the same. That's -- that's basically saying, yeah, I'm going to add intra-hour volatility, I'm going to have more problems, but we're not going to operate the system like that. The operators are going to be get back to the same level of reliability. So that goes against the complete premise of the study.

Q Well, I can't speak to whether it complies with the premise, but my point is, I think you've previously agreed to this, it's the NERC standards that Duke is required to operate its system against, correct?

A Yeah. Nobody's --

Q And --

OFFICIAL COPY

Jul 29 2019

A Nobody's refuting that.

Q And I think you further testified that if it is doing that, it is operating the system reliably, correct?

A That's right.

Q And so my question is on this correlation issue, you have this excursion or this increase of exceedances of the LOLE FLEX from 0.1 to 0.3. I understand that that indicates that you need more operating reserves to get back to 0.1, but what does it tell you about whether those -- the addition of those operating reserves are needed in order to comply with NERC standards?

A So it would tell me that if we allow LOLE FLEX without solar to be at 0.1, and then when we add solar, we're willing to go to 0.3, that we will, without a doubt, have more NERC imbalances than what we did in the 0.1 case. They are -- they are correlated. If the operating reserves increase, and I don't think there's any refuting that if operating reserves increase, then LOLE FLEX comes down, and at the next NERC stan--- the NERC imbalances would also decrease if we increase operating reserves.

Q Are NERC imbalances the same thing as violations of the NERC standard?

OFFICIAL COPY

Jul 29 2019

A Well, the NERC standard are calculating how many NERC imbalances you have, so yes.

Q I understand. But it -- but it allows a certain number of imbalances, correct?

A It does. It does.

Q So the fact -- the fact that the number may change doesn't necessarily mean that you would have more violations, does it?

A Say that again. I'm not following.

Q The fact that you would have more NERC imbalance events doesn't mean that a standard that allows a certain number of events would be violated to a greater extent, does it?

A Well, your -- your line of thinking and questioning there, though, is saying that we are willing to have an increase in balances. Yeah. It may not hit the standard, but that we're willing to have an increase in imbalances when we add solar than when we didn't have solar. And we're not -- I don't think anyone here would agree that when we add solar, we should -- we should allow more NERC imbalances on our system and get closer to a NERC standard violation which costs substantially large dollars to the balancing area.

Q Well, just for the record, I'm not sure that

OFFICIAL COPY

Jul 29 2019

everybody here agrees with the statement that you just made. Let me just ask you one more question again about this correlation issue. The -- one of the forms of so-called sensitivity analysis that you did was -- as you've said, was to calculate or model the increases to operating reserves that would be required with a less stringent LOLE FLEX metric, correct?

A That's correct. We went 0.1 to one.

Q And I believe what you found was that relaxing the metric did not reduce the quantity of additional operating reserves that would be required by a large number, correct?

A That's correct.

Q But, again, does that tell you anything about how changing the metric would change compliance with the NERC standard?

A No. What it tells me is that the reason the load following reserve impact is not that much different, is that going from 0.1 to one, when you think about the intra-hour solar volatility, is that we get there pretty quick when we decrease operating reserves, and so that -- that Delta there is pretty quick, so we can compare the -- and the economic results are fairly stable across that range.

OFFICIAL COPY

Jul 29 2019

Q But, again, to the question of correlation to what I would submit is the ultimate metric that matters, which is the NERC -- compliance with the NERC standard, my question is, are you able to determine whether there would be a greater number of violations of the NERC standard if you model the system to the LOLE FLEX of 10 rather than 0.1? Or --

A We --

Q -- I'm sorry. I may have gotten the numbers wrong. If you made the tenfold increase, do you have any basis for saying that that would result in a greater number of violations of the NERC standard?

A It would -- it would put our operating reserves at levels below what we've done historically which have met NERC operating reserves, but ultimately I still think you're getting at the point that you should be able to add solar and so you're -- so, basically, you've got a little bit of room in your NERC standards before you add solar. What I think you're suggesting is that if I add solar, I should be able to get a little bit closer, allow some more imbalances because of the solar, and not -- not manage that, but what I think the premise of the study is, and most integration studies that we've seen, is that the reliability before and after solar should be the

OFFICIAL COPY

Jul 29 2019

same. We should not further get closer to the line on a NERC standard which is what that -- that is suggesting, right?

Q Well, no. What I'm suggesting is that the ultimate metric is compliance with the standard. And it's for the Commission to decide. I suppose if they had the information with which to do it, how much margin of error should be allowed in the system.

A Yeah.

Q But, no, I'm just suggesting that. I don't think he's --

A That's -- that's fair. I mean, I think the only way to really do that is to tie the -- since we can't model it, we agree we can't capture the imbalances. We wish we could. We can't. So the best thing we can do is try to get a starting point that is not out of line with historical reserves that met NERC compliance.

Q All right.

MR. LEVITAS: Thank you. I have nothing further.

CHAIR MITCHELL: Thank you, Mr. Wintermantel.

THE WITNESS: Thank you.

CHAIR MITCHELL: You may step down for the moment.

OFFICIAL COPY

Jul 29 2019

MS. BOWEN: And then SACE calls Witness Brendan Kirby back to the stand.

THE WITNESS: Good morning.

CHAIR MITCHELL: Good morning, Mr. Kirby. I'll remind you that you remain under oath.

THE WITNESS: Yes. Thank you.

COMMISSIONER GRAY: Please pull the microphone.

CHAIR MITCHELL: Questions from the Commission?

BRENDAN KIRBY; Having been previously sworn,
Testified as follows:

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Good morning, Mr. Kirby.

A Good morning.

Q Thank you. I've got less for you than I would have had if you had started before Mr. Wintermantel, but -- so we'll see -- see if we can make it a little shorter. But I want to start where Mr. Levitas left off here a little bit. As I recall your testimony yesterday, you were of the opinion that the standard we should adhere to is compliance with the NERC reliability criteria, and that's a different standard. Would you agree with me that maintaining the same degree of reliability as existed prior to the addition of solar to Duke's fleet, that's a different standard, isn't it?

OFFICIAL COPY

Jul 29 2019

A I'm sorry. Could you repeat that?

Q Okay. We've got two different standards here, don't we? One is compliance with the NERC reliability standards.

A Yes.

Q That's an -- that's an absolute standard.

A Yes.

Q The other standard I would call a relative standard, and that is maintenance of the same degree of reliability --

A Oh, okay.

Q -- post-addition of solar, as existed on the system pre-addition of solar. That's a different standard. It's a relative standard.

A Yes. And we did discuss that yesterday.

Q Right. And -- and do I recall correctly that you were of the view that a -- a well-managed utility, without knowing and having studied the matter, likely -- very likely would be managing on a somewhat conservative approach to the absolute standard --

A Yes.

Q -- but would not be managing either -- certainly not managing under the standard, violation of the standard, but would not be managing excessively

OFFICIAL COPY

Jul 29 2019

conservatively?

A Yes.

Q But we don't really know for sure about Duke, and I respect that nobody here has said that they do, right?

A Right. And if I could --

Q Right.

A -- when we discussed that, the reason I sort put that caveat in --

Q Right.

A -- because I think we actually all agree that -- that the way you do these studies, the appropriate way to do these studies is you have a level of reliability before and you have the same level after. But then if you're off kind of in an academic theoretical discussion, could there be a case that wouldn't -- where you would not do that? Yes, there could. If your utility beforehand happened -- for whatever reasons it had no variability, then would you try and hold that after? And the answer would be no.

Q Right.

A I do not think that applies here. That was just as -- in terms of saying is your statement absolutely 100 percent? No, it's not. But in practical

OFFICIAL COPY
Jul 29 2019

terms, because all utilities -- any reasonable utility, it's got variability. So it's -- you know, Duke is going to be holding an appropriate amount more conservative than -- so -- so my point really was if the actual operations, I believe, will mirror that -- the ideal of how we try to do the study where the reliability before and after will be the same.

Q Okay. Thank you. I think -- that's helpful. I think what Mr. Levitas helped me crystalize was that the policy choice here that we have to decide is -- is are we going to be more focused on the absolute standard or on the relative standard. And we'll -- that's a determination I think we will -- we will be making.

A Yeah.

Q So my question to you next is, leaving aside the absolute standard, let's park it in the corner for a minute, and let's assume that we're trying to achieve the relative standard.

A Uh-huh.

Q Okay. Do you think the Astrapé model is a reasonable approach to that task?

A No.

Q All right. After having heard Mr. Wintermantel this morning and yesterday, give me again, as quickly and

OFFICIAL COPY

Jul 29 2019

in a nutshell as you can, after you heard it all, why it's not a reasonable way to accomplish the relative standard, as I call it.

A Yes. I believe that they're actually -- that distinction between the relative and the absolute is -- would only be important in some sort of theoretical sense. So I think that what I'm -- what -- the whole time I've been talking about it has been in what you're now calling the relative sense --

Q Okay.

A -- so the practical way that the operators are going to operate. So saying that --

Q Okay.

A -- now I'll try and address your question, why I don't think the modeling actually did that. And it gets to -- basically, let me bring up two points. One will be the 10,800 times worse, the LOLE FLEX metric, and the -- and my brain just lost it on the second, but I'll -- I'll come back to it. Let me address -- address that.

You know, I brought -- I stated that the LOLE FLEX metric is 10,800 times more stringent than what was used for Idaho. And the reason -- and that was being done as an explanation for, you know, if you look at five minutes -- one 5-minute interval in -- oh, I've got the

OFFICIAL COPY

Jul 29 2019

other -- one 5-minute interval in 10 years versus 90 hours a year, that's what that ratio is. Now, what I'm not saying is that, oh, well, just -- just take the LOLE FLEX and adjust it by 10,000 times. No. The point was that the LOLE FLEX is just not -- it is not -- it doesn't have a tie to the physical reality of what it is we're trying to do. And while -- while modeling -- precisely modeling the physics of the -- the two NERC BAAL requirements, CPS1 and BAAL, while -- you know, as we've all agreed, you cannot do that precisely. You can do modeling that gets close, and it is still based on the physics of what's required.

The entire rest of our modeling, the production cost modeling, is based on physically mirroring the reality. We know -- we know what generator heat rates are, and so when we model them, we model them at a certain power level and we use the heat rate, we say, oh, well, this is how much fuel they're burning. We're trying to have the model mirror what is physically happening. Now we've come to a new phenomena of looking at a lot of solar, a lot of wind coming in, and we've -- we're needing to come and look at what are the changing reserve requirements.

Well, our model needs to be based on physical

OFFICIAL COPY

Jul 29 2019

reality. And so the -- the problem with the LOLE FLEX is that it is -- it is requiring this one 5-minute interval in -- only allowing one 5-minute interval in 10 years, and that is so far divorced from what the balancing requirement is that -- that you need to find something that is -- that is much closer. And -- I'm sorry. You have a question?

Q Well, this I understand. I'm trying to take us beyond where we were yesterday a little bit to sort of advance my knowledge a little bit beyond where we were -- where we got to, and I thank you for that. So let me ask it this way, is -- is the LOLE FLEX metric, is that the appropriate metric to be used in -- in consequence of the fact that there -- the condition of the model is perfect knowledge?

A Ah, thank you. That --

Q Is -- is -- isn't that the reason --

A No.

Q -- that the LOLE FLEX model is driven by the perfect knowledge condition of the model?

A Thank you for that because like I said, I was just leaving my brain for a second. This -- this whole question that's come up of the perfect knowledge is -- it is a red herring. And it -- we're getting sidetracked on

OFFICIAL COPY

Jul 29 2019

-- you know, it is not relevant to the issue. And why do I say that? As Mr. Wintermantel said, and I agree with him completely, the -- you know, the SERVM modeling, the entire modeling, it very much is including or trying to include solar variability and uncertainty. And it's including, as he said, hour ahead, day ahead, all of that has to be built in there and, you know, I applaud them for that. That is what you need to do. If that was not in there, the modeling would not be being done correctly.

The place that we're getting into the perfect knowledge is saying, oh, wow, at the 5-minute interval, then we lock in the net load, the solar plus load, and we then look at -- and we know the next 5-minute interval so we know those two points. And we just look at does the system have enough ramping capability to make it between those two points.

Q Okay.

A And then we say, oh, wait a minute, in actuality, things are going to be more variable in between. So we know the two end points; we just don't know the path. And, you know, there we say, wow, that could be -- the solar could move in a bad direction. That could be an imbalance. Absolutely true. Turns out it doesn't matter.

OFFICIAL COPY

Jul 29 2019

The reason it doesn't matter -- or it doesn't matter much. It's a good thing to be aware of, but the reason it does not have an impact on -- on the results is -- is -- and I will provide you with an example of our evidence of where Duke agrees. So the reason it doesn't matter is because the two metrics we have or the two, you know, two is CPS1, which looks at annual average of 1-minute bad deviations. There are good deviations that help. So we say, okay, in this 5-minute interval we might be seeing some more bad deviations and some good deviations. So those will -- those will be happening, but that only impacts this annual average limit. So if I happen to have a bad 5 minutes or two, I've got a year to make up for that.

The one that really gives you more trouble for actually operating is the BAAL metric, and that is a metric that says -- B-A-A-L is the second -- it's the second of the two limits that you have to follow that's within that -- and I apologize for NERC's acronyms. The standard is called BAL-001-2, and within that you've got CPS1 and BAAL. All right. Well, the BAAL limit, which is also based on frequency, which is what makes it so hard to actually just say I'm going to just model the darn thing, is that says you're only in violation if

OFFICIAL COPY

Jul 29 2019

you're -- if your imbalance lasts for 30 minutes, so that's why the five minutes doesn't matter.

Q Okay.

A Now, could you -- and there it gets into one of the subtleties, too. So say, well, fine, just go for a 30-minute limit. Well, no. It would not be appropriate for a system operator to allow the system to -- to go and balance it and every 29 minutes, you know, fix it. That's no good. So you have to go shorter than that. On the other hand -- and here's the -- here's why you can't just put a single number in; you've got to be a little bit smarter and really looking at your results. If you were to run 10 years of study and you found one -- one instance where the LOLE FLEX was -- you missed it for six consecutive times or five consecutive times --

Q All right.

A -- so that would be five -- five in a row where you missed it, okay, now you're getting close to -- to actually hitting a NERC limit. So that would be worth waking up on. And I would say, okay, if that happens once in -- in 10 years, that's interesting, you might want to look at it, but that is no violation. That's no big deal. If that was happening once a day, you know, I'd say that's inappropriate.

OFFICIAL COPY
Jul 29 2019

So, for example, an alternative would be to say rather than looking at the LOLE FLEX of, you know, single isolated instances and counting those, you need to look at do I get five of them in a row. If I get five of them in a row, then I need to wake up. What are the reserves it's going to take to -- so that I can deal with five of them in a row? And I would even go so far as to say you might want to be tighter than the five in a row if it happens real frequently.

Q Excuse me, though, but it seems that in the explanation, if I've been following you, that you've suddenly shift me back to the absolute standard, not the relative standard.

A No, sir.

Q And so if what I'm wanting to do here is to maintain my relative --

A Yes.

Q -- situation pre and post, doesn't the perfect knowledge condition actually give me the guidepost on exactly what I have to do in order to ensure that?

A No, sir.

Q It says that if -- if I can meet that -- if I can meet that, if I can -- if I can ramp -- with perfect knowledge of net load, if I can ramp to that, then I've

OFFICIAL COPY

Jul 29 2019

got adequate reserves that I had before. Doesn't that guarantee me that?

A Oh, in fact, yes, it does guarantee that.

Q But -- but --

A It way overcomplies.

Q It overcomplies --

A Yes.

Q -- with the absolute standard.

A No, sir.

Q Talk to me more.

A Okay. In -- in today's operating environment --

Q Right.

A -- the system operators are not able to meet -- you know, it's not that they're missing at every occasional minute or two, but by gosh they nail it every five minutes. No. That's not their requirement, and if -- if there are instances in time where they've missed it for five, 10, 15 minutes, that -- you know, that's getting their attention, but it is not a violation. They're not going to go to herculean efforts to -- to avoid that.

Q Okay. I follow you. And so -- so a minute ago you sort of said it would be imprudent to essentially use

OFFICIAL COPY
Jul 29 2019

a 30-minute interval to -- to construct the model. Well, what about a 10-minute interval?

A No. No. My point there is --

Q Well, what do the -- what do the operators actually -- when would you expect an operator to actually sort of sit up and take notice?

A That is my point, is that you wouldn't want to pick one number and apply it for 10 years. You have to be a little bit more subtle than that. Not much more subtle.

Q How much more subtle, again, because for modeling purposes I can't be in real time. I can't do it in real time. We've already understood that. We can't do it in real time, so for modeling purposes --

A Oh, no. No, no. This isn't hard.

Q All right.

A This isn't hard. So my point is that as you added reserves -- and so my problem with LOLE FLEX is that it looks at it and it says one 5-minute interval and that's it. I need to -- in 10 years I need to add more reserve.

Q All right.

A And my point is, no, that wouldn't be -- that's not right. So an alternative would be I'm going to look

OFFICIAL COPY

Jul 29 2019

and say do I hit -- do I hit five in a row? Do I hit six in a row to hit the 30 minutes? If I -- if I hit six in a row, that's a problem. But then what I would want to further look at is, you know, and what I'm trying to say is, so would I pick that as the limit and say if it's 30 minutes and I'll just meet that? I would want to be a little more careful and I would want to say, well, when I hit my limit of 30 minutes, did I hit it once in 10 years or was I hitting that daily?

And I would agree completely that hitting it once in 10 years, you're fine. Hitting it daily, no. You need to -- you need to be tighter than that. But I wouldn't go and say, well, then why don't I just make it a 10 minutes and, you know, because making it tighter all the time wouldn't be appropriate if it turns out that the way the system conditions are, that what's driving you is to add tons and tons of reserves to dodge one event in 10 years. The system operators wouldn't do that and it would be imprudent to -- to either operate that way or to -- to create an integration charge implying that you would operate that way. So it's just not a single number. It's a little more of a curve that you'd look at.

Q Thank you. Would you comment on the dialogue

OFFICIAL COPY

Jul 29 2019

that was had about the post-processing stress testing that was done on the Astrapé LOLE FLEX 1.0?

A Yes.

Q I'm not sure you were asked about that yesterday. If you were, I don't remember it, so I'll ask you that again.

A Well, that kind of goes to my point, that -- that when I was saying that the LOLE FLEX metric is, you know, 10,000 times different than what was used for Idaho, I was, again, only using that to really emphasize the fact that it's really, really different. And my point is not that it needs to be shifted by that amount, which gets to the question of the stress testing. So it's not a question -- it's that the metric is not mirroring the physics of the system. So, yes, and I also agree it's heartening to see that when -- you know, that when they shifted by a factor of 10, which I agree on most parameters a factor of 10 is a -- is a large amount, similar to what Idaho found.

You know, fortunately, when we look at these systems and the reserve requirements, because we're going through the process of holding the same reliability before and after, that -- the target we're looking for is a level of reserves that when we are not sufficient, the

OFFICIAL COPY

Jul 29 2019

system gets really insufficient. So -- so when you've -- if you're short -- if you're genuinely short on reserves, you're probably hitting problems all the time, you know, which means -- which is why you don't want a metric that says I want perfect because you -- you hit the -- you can't meet the perfect a relatively small number of times, and you don't want those to drive you and NERC require it to. I'm not sure I'm getting...

Q No. I mean, because all I want to do, at least hypothetically, not -- not from -- but all I want to do -- suppose all I want to do is maintain the same level of --

A Yes. Absolutely.

Q -- reliability that I had before.

A Yes, yes. Yeah. No. What I'm trying to get to is the question of the stress testing is the point that -- and I agree completely, that the -- if you're -- you know, that a good measurement of the reliability requirement, it actually will be relative -- you know, as long as you're getting in the ballpark, it's going to be relatively insensitive. So what that means is matching the exact NERC requirements is not required. It's necessary to be in the ballpark. That's why it was fine for Idaho to pick 99 percent, even though 90 percent is probably more realistic.

Q Right.

A The problem with LOLE FLEX is it's not mirroring the physics of how the system is working. So whether you can run a case where it happens to have the same reserves, you know, under a base case, that's good, but it's not sufficient. It's necessary, but not sufficient. It's not necessarily reflecting how the system is going to respond in terms of required reserves under a condition with very different amount of solar variability rolled in.

Q All right. Let me -- let me back up. And thank you. Let me back up, then, for a minute, and I'll ask you a somewhat higher level question here. Is there any respect in which the concepts that drive and are used in resource adequacy planning can be translated into the task at hand, which is essentially -- isn't that what Astrapé has done by using the LOLE FLEX model? The way that they've gone about modeling is really derive from a resource adequacy planning approach. And is there any -- do you think there's any validity in that basic approach, even if it may produce a different metric? You might produce a different metric coming out of that. But I'm talking about now the methodological approach of starting

OFFICIAL COPY

Jul 29 2019

OFFICIAL COPY

Jul 29 2019

with a resource adequacy type of process and then trying to derive a model that will yield the appropriate charge here. Is there any -- any model that could be produced using that approach that you think would have validity?

A I'm having problems with you're -- you're tying the resource adequacy approach --

Q Right.

A -- or the modeling approach. My problem is that resource adequacy, we look at things like one in 10 years is perfectly reasonable.

Q All right.

A And so -- and, also, loss of load expectation.

Q That's what we're doing here.

A Exactly. And my point is that those -- that both the name, it's completely inappropriate because the violation, while it does result in loss of load under resource adequacy, in this case it does not result in loss of load. It results in a -- well, and it doesn't even result in a BAAL violation. So that doesn't make sense. I have no problem with the way the modeling was done, the whole concept of the -- of production cost modeling. It's all very good. The security constraint, unit commitment economic dispatch, modeling the whole system, going out for 10 years, doing an hourly

OFFICIAL COPY

Jul 29 2019

production cost, going to sub-hourly production cost, all of that is very, very good. That's what we want to do. Holding reliability before and after, that's all very, very good.

The only problem in there -- well, the only two problems in there are the -- the metric, the -- the -- what's driving the question of was I reliable enough, is fundamentally divorced from -- from the concepts of what NERC balancing requires. And the second problem is the question of whether when you add more and more solar, if you are correctly scaling its variability.

Q We talked about the scaling issue yesterday.

A Yeah.

Q I don't have anything further for you on that today, so I'm going to leave you alone for now.

A Thank you.

CHAIR MITCHELL: I just have one very quick question for you.

EXAMINATION BY CHAIR MITCHELL:

Q And, again, apologize if I'm -- if my question has you retread ground that you've already taken us through, but do I understand that you do not take issue with the base case in the Astrapé studies? We've heard a lot about sort of establishing that baseline, sort of

OFFICIAL COPY

Jul 29 2019

system condition, and then what they've done is they've added solar to that baseline. Do you take issue with the baseline, any component of the baseline?

A The -- my only issue with the way the modeling is done is the -- the use of the LOLE FLEX --

Q Okay.

A -- metric --

Q Okay.

A -- both in the baseline and the other. So -- but the concept of doing the baseline and doing -- that's very good modeling.

Q Okay.

CHAIR MITCHELL: Any additional questions from the Commission?

(No response.)

CHAIR MITCHELL: Questions on Commissions' questions?

MR. LEVITAS: I have one. Yeah. You go ahead.

MS. BOWEN: Do we need to go first?

CHAIR MITCHELL: Yes, please.

EXAMINATION BY MS. BOWEN:

Q Just one. In -- in trying to mirror how system operators actually operate the system to make sure that they comply with the NERC standards, I know that in your

OFFICIAL COPY

Jul 29 2019

testimony you included an Exhibit D. Do you have that or do you remember what I'm talking about? It's the Duke Energy presentation about system operations?

A Oh, yes. Yes.

Q Do you have a copy of that?

A I think you can probably ask your question and, in fact, I was going to refer to that.

Q Sure. Well, and I think you'll be able to do this better than I can, so I'm going to leave it to you, but how does that exhibit -- and we can also find you a copy -- but how does that -- how does that kind of help explain how -- the way that, number one, that systems change, operators respond to that, and second, it's two part, how does that explain the situation that what they're modeling is divorced from reality?

A Thank you. Yes. And this gets to the question that Commissioner Clodfelter asked about the 5-minute balancing. And so what -- what this -- what this exhibit is, is a presentation that Duke made to the NERC Operating Committee on June of 2019. I'm sorry. Go ahead.

COMMISSIONER CLODFELTER: For the side bar. Were you asking me a question?

THE WITNESS: No. I apologize. What I -- I

OFFICIAL COPY

Jul 29 2019

was waiting because I didn't want to interrupt what you -- what you were doing.

MS. BOWEN: And Commissioner Clodfelter, I believe Mr. Kirby was recognizing that he was responding to one of the questions that you asked --

THE WITNESS: Yes.

MS. BOWEN: -- earlier about the 5-minute -- 5-minute increment.

THE WITNESS: Yes.

A And so this -- this presentation that Duke make to the NERC Operating Committee where they were talking about the retuning of the AGC, so the retuning of their automatic generation control, which is what it is that they use to meet the -- the balancing standards. And the point they were making was that as more and more solar came on, that what they found effective to do was to detune the AGC so it was not trying to chase the -- the fast minute-to-minute deviations. And by doing that, they got better response -- they got better -- better performance on the BAAL, B-A-A-L, metric, and it had negligible impact on the CPS1. So basically what they were doing was saying let's not worry so much about this 5-minute interval, and we'll worry more about approaching the 30-minute interval.

OFFICIAL COPY

Jul 29 2019

So the actual operators are -- you know, are not saying, oh, my gosh, my real problem is this very short, you know, where I have to just chase this very fast movement. They're saying, no, what we're recognizing is even though our AGC moves at, you know, probably setting AGC commands out at -- they're getting data in at something like two seconds and probably sending AGC commands out at six seconds. And they said let's slow that down and not chase that quite so -- so hard. And -- and so you would think I'm -- boy, I'm not trying to balance so well. Isn't that going to hurt me for NERC? And the answer is no. It improves the BAAL performance and it doesn't hurt you on your CPS1.

MS. BOWEN: That's all I had. Thanks.

MR. LEVITAS: Just one quick question from me. Oh, I'm sorry.

THE WITNESS: You seemed like you had a question on that?

FURTHER EXAMINATION BY COMMISSIONER CLODFELTER:

Q In other words, it's a -- it's a non-resource addition way of managing the issue of volatility. It's an operational change --

A Oh, yes.

Q -- rather than a resource change.

OFFICIAL COPY
Jul 29 2019

A Yes.
Q That's what you just said.
A Yes, yes. And it's part of your process to find -- which is what they do so well, and that actual operations really helps you with, is you're constantly -- you know, you're constantly meeting those CPS and BAAL standard --
Q Right.
A -- and so you keep finding, well, what can I do that says, well, I'm going to meet it, but I can meet it at the lowest cost. I want to meet it conservatively. I don't want to risk, you know, getting violations, but I also don't want to waste money. And that's -- you know, they get to run them on the real-time computer and, you know, their -- their results are accurate. I mean, you can't argue with the results.

EXAMINATION BY MR. LEVITAS:

Q Mr. Kirby, do I understand correctly that it's your position that if a utility were to be operating its system such that the goal was to have only one 5-minute imbalance over a 10-year period, that that would be excessively conservative operation of the system?
A Yes.
Q And so if that were to be set up as the before

OFFICIAL COPY

Jul 29 2019

standard, and the goal of solar integration was to try to replicate that performance level, your position would be that that would also be excessive and far in excess of what would be needed to comply with NERC standards, correct?

A Yes. Yes, that is, but -- but kind of from a modeling perspective, it -- it probably is not an indication that you just need to back that dial down. It's probably an indication that you're not -- you know, you've got them wrong, but you're not doing the modeling quite right.

Q Okay.

MR. LEVITAS: Thank you.

A Subtle difference.

MR. BREITSCHWERDT: A few -- a few questions, if I could.

MR. DODGE: Mr. Breitschwerdt, I'm sorry.

MR. BREITSCHWERDT: Oh, I apologize. Go ahead, Mr. Dodge.

MR. DODGE: Just a couple questions here, too.

EXAMINATION BY MR. DODGE:

Q Mr. Kirby, in response to Commissioner Clodfelter's questions about perfect foresight, you mentioned that's kind of a red herring issue, but do --

OFFICIAL COPY

Jul 29 2019

do system operators in reality have perfect foresight?

A Oh, no, they do not. No, they do not.

Q And does the Astrapé model have -- provide for perfect foresight five minutes out?

A The Astrapé model, as Mr. Wintermantel said, you know, you go to a lot of effort -- and if you didn't, the study wouldn't be worth much -- you go to a lot of effort to include the solar variability and uncertainty, and you want in there. And it's in there for everything longer than that 5-minute interval. And so, yes, I will agree with you that there is the difference that they don't model the -- you know, that the system operator -- that the model is -- is -- you could say, you know, it's really ignoring that sub 5-minute interval. You could call that as perfect foresight, but as we see from -- from what the Duke operators are finding, is in detuning their AGC, the -- what happens over the immediate five minutes is not that critical.

Q Okay. And on that same point, and this is back to Commissioner Clodfelter's questions regarding what the goal here is of the solar integration charge, is, again, if the goal is either absolute compliance with the NERC standards or if we're talking about a relative standard, the margin of error that we're maintaining the same level

OFFICIAL COPY

Jul 29 2019

of reliability from the base case to the change case?

A Yes. We want to -- we want to mirror what the real system is doing, assuming that the real system is -- is operating efficiently and effectively.

Q Okay. And we've talked a lot about maybe some disagreements on the models and which one does that, but from a -- from a cost causation perspective --

A Yes.

Q -- which is our -- our big concern here, wouldn't the standard of maintaining the same level of -- the same margin of error, the same level of reliability pre and post provide you with the best information for cost causation purposes?

A Which is exactly what the Idaho study and all good studies are based on. All studies that are done well, you have a level of reliability before and you have to drive to the same level of reliability after. Absolutely agree that, you know, it would not be right to come in and load in any new resource and then say, well, let's go ahead and relax the standards, too. I mean, you might elect to do that because you found you could elect to, but you ought to then do that in the base case as well and save the money on the before, as well as on the after.

OFFICIAL COPY

Jul 29 2019

MR. DODGE: Thank you.

CHAIR MITCHELL: I have one -- one question --

THE WITNESS: Please.

CHAIR MITCHELL: -- before you ask yours, Mr. Breitschwerdt.

FURTHER EXAMINATION BY CHAIR MITCHELL:

Q Apologize. I meant to ask you this a minute ago. Mr. Kirby, Exhibit D to your direct testimony is a presentation that was made by DEP in June of this year to the NERC. Can you just briefly help us -- explain to us what you want us to understand from this presentation?

A Yes. From that presentation, to me, the critical thing -- well, several things. Very, very good presentation. It showed that the system operators are obviously aware of and looking at and working hard to deal with increased amounts of increased solar, given an increased variability. And let me find the exact page. There we go. Yes. Okay. It is. I thought it was -- slide 9. So if you -- the heart of it is -- is slide 9. And in slide 9 what they're saying is -- here's what they've done. They did AGC tuning, so they went in and messed with the way their automatic generation control responds to -- to variations. And the control bounds were relaxed to improve response performance.

OFFICIAL COPY

Jul 29 2019

So they said rather than to so tightly follow, to worry about every minute, because CPS is based on, you know, the -- even though the data comes in every couple seconds and controls go out every, say, six seconds, the -- the metrics are 1-minute metrics for -- for NERC balancing. So what it says is they relax the trying to meet that one minute, which you normally think, boy, that's -- that's got to hurt. What they found is the generators are better responding to sustained system needs, so it's getting them better performance on the actual ramps. They're no longer chasing fleeting events. It reduces the impacts from variable energy resource 1-minute volatility, so it reduced how much the solar was impacting in terms of needing more reserves. It improved the fleet efficiency. So by backing off and not worrying about the -- the sub five minutes -- and what they found, they got a 20 percent improvement in their BAAL performance, which is this 30-minute performance and the one that really drives what you have to do, and it did not hurt the CPS1, which is the annual average of 1-minute events.

So -- so my point is that what -- what the Duke operators were doing, which was absolutely right, is they're not focusing in on the fact that they don't have

OFFICIAL COPY

Jul 29 2019

perfect knowledge in that 5-minute interval. In fact, they came in and said, well, what we're going to go and do is -- is relax, detune -- relax what our automatic generation control, which is -- you know, it's a computer, so it's able to watch that real fast stuff and tell it back off.

CHAIR MITCHELL: Thank you, Mr. Kirby. That's helpful. Mr. Breitschwerdt?

MR. BREITSCHWERDT: Just a few questions.

EXAMINATION BY MR. BREITSCHWERDT:

Q So Mr. Kirby, we had a conversation yesterday about the history of the NERC BAAL standards. Do you recall that?

A Yes, I do.

Q And I -- you talked about how some utilities started complying with CPS to -- or strike that -- started complying with NERC --

A BAAL.

Q -- BAAL standard prior to July of 2016 when it became effective. Do you recall that?

A Yes.

Q And I am confident yesterday I asked you the question is the new BAAL standard more restrictive, and you responded, no, it's not.

OFFICIAL COPY

Jul 29 2019

A Correct.

Q And I'm also confident I just heard you explain to Commissioner Clodfelter that from a system operations perspective, the 30 consecutive minutes you have to comply with for the BAAL standard is more restrictive for a system operator; would you agree with that?

A It's more restrictive than the CPS1 requirement, which is -- which is still there. Remember that there are -- that the existing BAAL standard requires you, BAL--001-2, that it requires you to meet both the CPS1 and BAAL. And CPS1 looks at the 1-minute -- the 1-minute deviations, and it counts both ones that hurt and ones that help so you can get credit if your -- if your -- if you have a deviation that's helping. But that that's focused on the 1-minute is an annual average, and so it turns out that in actual operations, CPS1 is not what typically drives your -- it's not what's driving the system operators to say, wow, we're getting in trouble on CPS1; let's put on more reserves. If they're having trouble on BAAL, that gets their attention and they'll, you know, bring on more reserves to get them back in shape.

Q And that's what we're talking about here, correct --

OFFICIAL COPY

Jul 29 2019

A Yes.

Q -- is BAAL, right? And you had some discussions with Commissioner Clodfelter as well about from a system operations perspective, how far into that 30 minutes of time that, in your perspective, it's appropriate for a system operator to allow the system to exceed the standard or -- strike that -- not exceed the standard, but to approach exceeding the 30-minute standard. How many consecutive minutes up to 30 minutes that you think a system operator, in your perspective, would allow, and you said that -- at what point would a system operator notice, and when -- I think the language you used is at what point would be worth waking up on. And just so I'm clear, at --

A Yes.

Q -- what point in that standard, from your perspective, in those 30 consecutive minutes should a system operator start to take actions to respond?

A Yes. That --

Q What -- what minute? It's just a simple what minute in that process should the system operator take action to respond?

A That's a very good question, and the right answer is not what minute. The right answer is it

OFFICIAL COPY

Jul 29 2019

depends on what the system conditions are. So that's why the -- the Duke operators -- so you've got a computer that -- that's just doing -- you know, it's watching that deviation all the time and it's responding. And they told it here's how we want you to respond. We want you to respond a lot and aggressively and -- or however they -- and what they found was, especially as more solar comes on, back off. Don't be so aggressive in responding. Now, they don't say exactly -- they don't explain how much, but basically they moved whatever minute they had chosen to begin responding, they relaxed it, they made it later, and that got them better performance.

And here's the point I'm trying to get to, and I'm sorry for extending the discussion, but when we do -- when we do modeling, that's different than when we run the system in that we'll run 10 years of model and then we look at the results. So -- and we have a limit. The computer is looking at a limit and it says I can have one violation in 10 years. Well, that's -- I hit the one, that's it, I move on, I add reserves. The system operator is -- you know, depending -- it's going to depend on why he's missing -- you know, why he's missing the imbalance and what actions he's got to take to

OFFICIAL COPY

Jul 29 2019

resolve that. Well, he's an operator. He gets to see the conditions. So he gets to actually -- so you want him waking up and looking at it very quickly. If he has reason to know what -- what the -- event is happening, then he may let that -- he may let that go. If he sees that this is a solar variation and that he's been seeing them all day long and it's -- the cloud pattern is such that they're typically a 1-minute drop and they come right back, then he'll just let it go. And if it doesn't correct itself in what he thinks is a reasonable amount of time, then he'll wake up.

In the modeling what you'd want -- need to do would be you would need to then have not just one number, but a little bit of a range, and look at am I -- am I viola--- am I looking like I'm going to be violating -- well, you won't violate the NERC standards ever, but am I getting to excessive lengths of imbalance a lot of times or just if it's once in 10 years, it's not a big deal. If it's every day, that's a big deal.

Q Just -- you still haven't given me a number. Is it five minutes, is it 10 minutes, is it --

A And you're asking --

Q -- 25 minutes?

A -- about -- and you're asking about what an

OFFICIAL COPY

Jul 29 2019

actual system operator would do?

Q I'm asking based on your position today, what is reasonable, because I heard earlier that --

A And I apologize. Are you asking what's reasonable for an actual system operator or what's reasonable in a model?

Q An actual system operator first, and then what's reasonable in a model, because I understood them to be the same until you just suggested there's a difference.

A Well, no. The system operator is there. That's his job. So he is -- he should be awake and paying attention, and when his -- when the system is out of balance, you know, he should be aware that he's -- that he's got a 1-minute violation. Should he take action? No. He should be looking at -- at why is he? Does he have reason to -- to think that there is an event? If he has no reason to think an event -- so if he has a good explanation, he might go out as far as 20, 25 minutes. And if he has reason that he -- that he has -- and he has reason to think that that's going to -- to fix itself. If he has reason and he can get himself back in the 30 minutes, that's perfectly -- perfectly fine. That would be a very rare event, and it would be -- so I'm

OFFICIAL COPY

Jul 29 2019

trying to say it would be an event with extenuating circumstances, but he would obviously be aware of that. So it could -- waiting that long to take drastic action could be perfectly appropriate.

Q So in real world operations, you said 20, 25 minutes, and then you are quickly approaching that 30 consecutive minutes that is a violation; is that correct?

A Oh, yeah. So -- so the system operator would have resources poised to be able to respond.

Q And is there any scenario where you would agree that allowing the violation of NERC standard would be acceptable for a system operator?

A The term "acceptable" is tough in that -- you know, so my first reaction is, no, it's not acceptable. Could it ever happen? Sure, it does happen. Do you miss NERC standards? You can have a really bad day.

Q You can miss a NERC BAAL standard --

A Well, I can think of --

Q -- and that's acceptable?

A No, no. I did not say it was acceptable, you know, but -- no. So I would agree. No, it's not acceptable.

Q So in the context of the modeling, you talked about this presentation that Mr. Adam Guinn --

OFFICIAL COPY

Jul 29 2019

A Yes.

Q -- from Duke gave.

A Yes.

Q And would you agree with me that what he's trying to solve for in terms of reducing the impact of variable energy resource with solar --

A Yes.

Q -- was 1-minute volatility? This is the third bullet on slide 9, so this is right under the bullet where it speaks no longer chasing fleeting events.

A Yes.

Q And so it is not 5-minute which is what Mr. Wintermantel has been studying towards in the Astrapé model. Would you agree with that? Does it say 1-minute volatility?

A It does say 1-minute volatility, yes.

Q It does. Did you hear Mr. Guinn's presentation or did you just find the --

A No.

Q -- presentation online?

A I've only seen -- I've only seen the presentation, yeah.

Q Okay. And from a modeling perspective, would a period longer than a 5-minute exceedance be -- not an

OFFICIAL COPY

Jul 29 2019

exceedance, but modeling towards five minutes or longer be acceptable in terms of the imbalances that would be allowed?

A Sure. The BAAL standard says that the hard limit is at 30 minutes.

Q So if you assume that from a system operation's perspective, let's just say the Duke Energy system operators, if they're five minutes into the 30 minutes, they start to take responsive action. Let's assume that as fact, that that's acceptable from system operation's perspective. It's your opinion that from a modeling perspective it would be acceptable to push closer to that 30 minutes?

A So in doing the modeling, I think that the modelings look at 5-minute intervals and to -- to adjust its balancing based on five minutes. I think that's very -- that's very reasonable. I think the -- the concern that, well, the model is assuming perfect foreknowledge or ignoring the 1-minute deviations is also perfectly reasonable. I don't think that has any impact on -- on the actual results or the way the model will differ from reality, so I think that's perfectly fine.

So doing the modeling at 5-minute intervals is -- is -- that's fine, and I -- what I'm trying to say and

OFFICIAL COPY

Jul 29 2019

trying to be clear on, is that then if you were to look at not just one violation, but if you were to look at -- at 30 minutes of violation, so six in a row, you could set the model up to say six violations in a row is unacceptable. I would agree that, you know, that would then be -- would be then matching or getting very close to the -- the NERC requirements, okay. But I'm -- I'm willing to go further than that, which I'm actually -- so if you wanted to be -- to be trying to drive the solar integration cost as low as possible, you'd say, no, that's it. Thirty minutes, that's what NERC says, and so do no more. I would agree that that -- leaving a 30-minute limit would not be appropriate. That is getting just too close.

So what I'm trying to say -- and the reason I was having a hard time coming out with saying, well, how many minutes is because if you -- if you hit, you know, five in a row one time in 10 years, that would be fine. If you hit five in a row every day, that would not be fine. So if I were doing the modeling and I was hitting five events in a row every day, I would up the reserves. I would not have a single number that says 30 minute.

CHAIR MITCHELL: Mr. Breitschwerdt, how much --

MR. BREITSCHWERDT: I've just got one more

OFFICIAL COPY
Jul 29 2019

question.

CHAIR MITCHELL: Okay.

Q And just to be clear, the Astrapé study does not model one imbalance in 10 years. You understand that, right?

A I disagree with that. Well, I --

Q Let me -- let me just point you to Mr. Wintermantel's direct testimony, and I'll read it to you and then I think we can conclude if you can agree with me that this is what it actually says. So page 17 of Mr. Wintermantel's testimony, going on to 18, says, "Is LOLE FLEX" -- "a generally utilized industry metric or standard for assessing reliability that is caused by a lack of flexibility?" "No. Operational reliability is governed by the NERC balancing standards and is measured by different metrics that cannot be easily captured in a production cost model simulated in 5-minute intervals. Ultimately, LOLE FLEX and SERVM is a measure of the system's ability to satisfy net load obligation assuming net load is known five minutes before it materializes." This is perfect knowledge. "While distinct from NERC balancing standards, any LOLE FLEX event should be viewed as a substantial violation of a system's obligation to manage its own load." So it is not -- it's not simply an

OFFICIAL COPY

Jul 29 2019

imbalance that occurs within the 30 minutes; it is a more significant violation where the system can't meet the net load ramping on a 5-minute basis. Would you agree with that?

A I would agree that's what he said. I would disagree with the statement.

Q Okay.

MR. BREITSCHWERDT: I think that's all I have. Thank you.

MS. BOWEN: Madam Chair, I do have just one follow-up question on the question that you had asked of Mr. Kirby after I had already asked my questions.

CHAIR MITCHELL: Okay. Well, we're going to take a break.

MS. BOWEN: Okay. Thanks.

CHAIR MITCHELL: And we're going to come back at 1 -- 1:50 -- 1:50.

(Recess taken from 1:11 p.m. to 1:50 p.m.)

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

MS. BOWEN: Okay. Thank you.

FURTHER EXAMINATION BY MS. BOWEN:

Q One question to follow up on Chair Mitchell's question for you. And she asked you about your Exhibit

OFFICIAL COPY

Jul 29 2019

D, the Duke presentation, and what you wanted the Commission to take away from that. And you pointed her to page 9, specifically. And on page 9 it talks about dispatchable generat--- improving response performance, responding to system needs, and dispatchable generators no longer chasing fleeting events. My question is, you know, how is that relevant here, and I think more particularly, how would you do modeling that reflects Duke's position here that generators should not be chasing fleeting events and could better respond to system -- sustained system needs by doing so?

A I -- I have two pieces to that answer, very quickly. One piece is that what Idaho did, when they ran into a problem with -- with modeling new events with new -- or new technologies and contention over how to do the modeling, they got a technical review committee, independent, outside experts that came in and helped to go through the whole process. Not just review the end product, but they looked at the process to say is this the right way to do the modeling, are the tools right, is the data right, the methodologies? That's something you might consider that might really help acceptance for the methodology and, therefore, the results.

The second answer, more specifically, a type of

OFFICIAL COPY

Jul 29 2019

answer they might -- the technical review committee might come up with is put a limit on that might be something like your -- you know, one 30-minute viol--- one 30-minute violation per 10 years is okay; on a daily basis no more than one 15-minute violation, so something that reflected that you can have more -- that if it's happening more frequently, it needs to be shorter. Long -- you know, long events, once in 10 years is okay.

MS. BOWEN: Thanks. That's all I have.

CHAIR MITCHELL: Thank you, Mr. Kirby. You may step down. Okay. We will now hear from --

MR. SMITH: NCSEA calls Witness Tyler Norris to the stand. I apologize. I have his summaries. Just one second.

CHAIR MITCHELL: While he's passing out the summaries, Mr. Norris, let's go ahead and get you sworn in.

TYLER NORRIS; Having first been duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MR. SMITH:

Q All right. While Lauren is so kindly passing them out, I will introduce you into the record. Could you please state your name and business address for the record?

OFFICIAL COPY

Jul 29 2019

A My name is Tyler Norris, and my business address is 5310 South Alston Avenue, Building 300, Durham, North Carolina 27713.

Q Thank you. And on whose behalf are you testifying?

A On behalf of NCSEA.

Q And, Tyler, did you cause to be prefiled in this docket on July 3rd, 2019, responsive testimony consisting of 31 pages and one exhibit?

A I did.

Q At this time do you have any corrections or changes to be made to that testimony?

A I do not.

Q And if I were to ask you the same questions today, would your answers be the same as given in your testimony?

A Yes, they would.

Q Thank you.

MR. SMITH: Madam Chair, at this time I move that the direct -- the responsive testimony and exhibit of Tyler Norris be copied into the record as if given orally from the stand.

CHAIR MITCHELL: Hearing no objection, the motion is allowed.

MR. SMITH: Thank you.

(Whereupon, the responsive testimony of Tyler Norris was copied into the record as if given orally from the stand.)

(Norris Exhibit 1 was identified as premarked.)

OFFICIAL COPY Jul 29 2019

118

OFFICIAL COPY

Jul 29 2019

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

In the Matter of:	)
Biennial Determination of Avoided	)
Cost Rates for Electric Utility	)
Purchases from Qualifying Facilities	)
– 2018	)

FILED
JUL 0.5 REC'D
Clerk's Office
N.C. Utilities Commission

RESPONSIVE TESTIMONY OF
TYLER NORRIS
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

OFFICIAL COPY

Jul 29 2019

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Tyler H. Norris, and my business address is 5310 South Alston Avenue, Building 300, Durham, North Carolina 27713.

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

I am employed by Cypress Creek Renewables, LLC (Cypress Creek) as Director of Market Development. In this capacity, I oversee our commercial strategy and policy engagement in the Southeast. On behalf of Cypress Creek, I serve on the Board of Directors of the North Carolina Clean Energy Business Alliance (NCCEBA) and South Carolina Solar Business Alliance (SCSBA).

Cypress Creek is one of the most active solar and solar-plus-storage development firms in the United States. To date, our company has developed 346 solar projects totaling 3,300 megawatts (MW), including 2,200 MW in North Carolina. In 2018, Cypress Creek constructed 52% of the 907 MW of solar capacity installed in NC, and we continue to own more than 1,000 MW of solar projects in the state, which we operate from our national control center in Research Triangle Park. In 2018, Cypress Creek brought online one of the first utility-scale solar-plus-storage systems in the Southeast, supplying Brunswick Electric Membership Corporation in eastern North Carolina.

Q. PLEASE DISCUSS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated with distinction from Stanford University in Palo Alto, CA with a Bachelor of Arts in Public Policy, where I received the Harry S. Truman

OFFICIAL COPY

Jul 29 2019

Scholarship, the federal government's highest recognition for public service leadership and academic achievement at the undergraduate level. I am a graduate of the North Carolina School of Science and Mathematics.

In 2012, I received a White House appointment to the Office of Secretary Steven Chu at the U.S. Department of Energy (DOE) in Washington, DC. As a Special Advisor for Commercialization, I spent nearly four years at DOE advising the Secretary and Assistant Secretaries on the development of programs to accelerate the commercialization of emerging energy technologies, and in crafting an enterprise-wide strategy for enhancing the commercial impact of DOE's multi-billion-dollar annual spending on energy research, development, and demonstration (RD&D). In this capacity, I was the lead author of DOE's first Technology Transfer Execution Plan, a report to Congress defining DOE's commercialization strategy for approximately $10 billion in RD&D programs.

Following DOE, I was a Director at S&P Global Platts, a leading international firm in energy market intelligence based in New York City, whose clients include a majority of the largest electric utilities and integrated majors. There I led the firm's U.S. solar and storage market analysis, among other market segments, providing forecasts and advisory services to electric utilities, integrated oil and gas majors, energy project developers, and institutional investors. In this role, I regularly advised and interacted with

OFFICIAL COPY

Jul 29 2019

utility resource planners as our clients, some of whom used my analysis and market insights to inform parts of their resource plans.

I have published about energy-related subjects in *Foreign Affairs*, *Harvard Law & Policy Review*, and *Issues in Science & Technology*, among other publications, and my work has been cited in the *New York Times*, *Washington Post*, *Vox*, *Greentech Media*, and elsewhere.

Q. DO YOU HAVE EXPERTISE ON THE SPECIFIC TOPIC OF UTILITY-SCALE ENERGY STORAGE?

A. Yes. In my capacity at S&P Global Platts, I led the firm's U.S. energy storage market outlook, which included an assessment of the present state of utility-scale storage technologies, markets, and policies, and a near- and medium-term forecast for storage deployment across all major U.S. electricity markets.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No. However, I recently appeared before this Commission during its Technical Conference on the Competitive Procurement for Renewable Energy on May 23, 2019 for Commission Docket Nos. E-7, Sub 1156 & E-2, Sub 1159. I also previously provided direct testimony before the South Carolina Public Service Commission on behalf of the South Carolina Solar Business Alliance in Docket 2019-2-E, Dominion Energy South Carolina's 2019 Annual Review of Base Rates for Fuel Costs. My testimony addressed the topic of avoided cost methodology and variable integration costs.

OFFICIAL COPY

Jul 29 2019

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the Commission's June 14, 2019 *Order Requiring Supplemental Testimony and Allowing Responsive Testimony* ("Order") requesting testimony on the topic of energy storage additions to electrical generating facilities. Specifically, that Order requested testimony to address what avoided cost rate schedule and contract terms and conditions should apply when a Qualifying Facility ("QF") adds storage equipment to a generating facility. The Order requested input regarding scenarios in which the facility has (i) established a legally enforceable obligation (LEO), (ii) executed a power purchase agreement (PPA), and/or (iii) commenced operation pursuant to an established LEO and executed PPA. Collectively, I refer to these as instances of a "committed generating facility" throughout my testimony. Although these categories of facilities may need to be treated differently for interconnection purposes, from the standpoint of rate schedules and contract terms, there is no reason to treat them differently, because in each case the QF has committed to sell its output to the utility and has established, under PURPA, a LEO giving it the legal right to sell its energy and capacity to the utility at long-term fixed rates equal to avoided cost, calculated as of the date the LEO was established.

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. My testimony is structured as follows. First, I briefly address the broader significance of market access for energy storage. Second, I review the

123

OFFICIAL COPY

Jul 29 2019

potential value of storage additions to committed generating facilities, particularly to the state's operating solar asset base. After establishing the potential value of solar-plus-storage resources, I discuss the positions of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC (together, "Duke Energy") and Dominion Energy North Carolina ("Dominion", collectively, "the utilities"), as presented in their June 25, 2019, Supplemental Testimony in this proceeding, and the implications of those positions for the deployment of storage in North Carolina. Finally, I provide a recommendation on how to approach the specific question posed by the Order.

As I discuss in greater detail below, NCSEA proposes a compromise approach in response to the Commission's question posed in its June 14 Order. Under this approach, if a QF seeks to add energy storage to a committed generating facility, the output from that storage equipment would be eligible for the then-available avoided cost rate schedule. NCSEA believes this position represents a highly reasonable compromise to enable market access for emerging storage technologies in a way that serves the interests of ratepayers and addresses the concerns of the utilities and Public Staff.

Q. PLEASE DISCUSS THE GENERAL SIGNIFICANCE OF STORAGE RESOURCE ADDITIONS TO PROVIDE CONTEXT FOR THE QUESTIONS PRESENTED IN THE COMMISSION'S JUNE 14 ORDER.

A. It is broadly recognized that energy storage resources in general, and utility-scale batteries in particular, will play an increasingly significant role in enabling a more affordable, reliable, and sustainable electricity system. It is in part for this reason that in House Bill 589 (Session Law 2017-192) the North Carolina General Assembly required a study on energy storage technologies to assess their potential value to North Carolina consumers, and to identify existing policies and recommended policy changes that may be considered to address a statewide coordinated energy storage policy. The results of the study were published in December 2018 by NC State University. As that study concluded, "Energy storage can help ensure reliable service, decrease costs to rate payers, and reduce the environmental impacts of electricity production."[1]

It is also in part for this reason that the Federal Energy Regulatory Commission (FERC) issued a major decision on February 15, 2018 in Order No. 841 for the explicit purpose of removing barriers to storage resources in the capacity, energy and ancillary services markets operated by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). As FERC stated in that Order, "we find that existing RTO/ISO market rules are unjust and unreasonable in light of barriers that they present to the participation of electric storage resources in the RTO/ISO markets, thereby

[1] North Carolina State University. *Energy Storage Options for North Carolina.* Prepared for the NC Energy Policy Council Joint Legislative Commission on Energy Policy. December 2018 ("NCSU Storage Study"). The NCSU Storage Study has been attached here as **Exhibit 1.**

reducing competition and failing to ensure just and reasonable rates."[2] And on April 19, 2018, FERC issued Order No. 845, which amended its interconnection rules to remove potential barriers to the interconnection of storage resources on FERC-jurisdictional systems.[3]

As it does not participate in an ISO or RTO, Duke Energy remains outside of such federal regulatory guidance and will not be required to comply with FERC Order 841, nor has the utility indicated an intent to voluntarily modernize its market rules. Instead, Duke Energy is proposing unjust and unreasonable barriers to market entry for energy storage resources – particularly with respect to power purchase terms and conditions and interconnection standards – that will wholly obstruct the addition of such resources to the vast majority of installed renewable generating facilities in North Carolina. Duke Energy is proposing such barriers despite its expressed concerns regarding the non-dispatchability of those generating facilities, which can be mitigated with energy storage.

It is the view of NCSEA and Cypress Creek that it is incumbent upon this Commission to make decisive regulatory interventions to remove barriers to market entry for energy storage, in the context of this proceeding and beyond. The immediate issue before us concerns the removal of barriers to the addition of storage to committed generating facilities, whose value to rate-

[2] Federal Energy Regulatory Commission. Docket Nos. RM16-23-000; AD16-20-000; Order No. 841. February 15, 2018.
[3] Federal Energy Regulatory Commission. Docket No. RM17-8-000; Order No. 845. April 19, 2018.

OFFICIAL COPY

Jul 29 2019

payers can be significantly enhanced by those additions. This particular matter is one of substantial importance for the Commission to consider, not least because more utility-scale solar is installed in North Carolina than any state except California, in terms of both the number of operating projects and in terms of aggregate capacity.

Q. CAN STORAGE RESOURCES ENHANCE THE VALUE OF EXISTING GENERATORS IN NORTH CAROLINA?

A. Yes. North Carolina's installed solar resource base of more than 5,400 MWdc represents a major infrastructure asset for the state into which the independent power production industry has already invested on the order of $10 billion. That investment includes hundreds of millions of dollars in upgrades to the state's electrical infrastructure, which are almost exclusively funded by independent power producers rather than ratepayers. This installed resource base presents a unique opportunity to take advantage of emerging storage technologies in the form of solar-plus-storage, and it represents an opportunity for this Commission to establish model regulations for solar-plus-storage.

As concluded by the NCSU Storage Study attached hereto as **Exhibit 1**, lithium-ion batteries in particular can enhance the value of utility-scale solar generators to ratepayers in a variety of ways over the near- and medium-term, including but not limited to the following:

a) Bulk energy time shifting,

b) Peak capacity deferral,

OFFICIAL COPY

Jul 29 2019

c) Solar clipping,

d) Flexible ramping,

e) Frequency regulation,

f) Voltage support and control,

g) Circuit upgrade or capacity deferral,

h) Transmission investment deferral, and

i) Transmission congestion relief.

The avoided cost rate schedule currently offered by North Carolina's regulated utilities does not value most of these services, unlike a growing number of tariffs in other jurisdictions. Indeed, the NCSU Storage Study identified the development of new tariff structures as one of the most meaningful steps the state can take to facilitate market entry.[4] To that end, NCSEA recommends that prior to opening the 2020 avoided cost proceeding the Commission initiate a separate proceeding to determine what new or modified tariffs are needed to appropriately compensate storage for its full range of services, as provide by Senate Bill 510 in the 2019 Session.[5]

Nevertheless, even the existing avoided cost rate schedule under consideration in this docket can tap into some of these value streams, particularly those related to time-shifting, peak capacity deferral, and solar clipping. Storage can enable existing solar generators to become more

[4] **Exhibit 1**, p. 164.
[5] General Assembly of North Carolina. Session 2019, Senate Bill 510. *Promotion of Energy Storage Investments.* April 2019.

OFFICIAL COPY

Jul 29 2019

dispatchable, storing solar generation during off-peak periods when it is needed less – or at times when that generation would otherwise be clipped or curtailed altogether – and instead discharging onto the grid when the output is needed most and provides the greatest ratepayer value. In turn, this solar-plus-storage resource can help avoid the cost of expensive new peaking capacity, especially from natural gas combustion turbines, which also impose negative externalities on the public health and environment of North Carolina.

The discrete value streams from time-shifting, peak capacity deferral, and solar clipping are likely to be substantial. In fact, the NCSU Storage Study concluded that bulk energy time-shifting and peak capacity deferral alone may prove cost-effective for up to 5,000 MW of lithium-ion (Li-ion) batteries by 2030, especially with higher solar penetration levels – and even sooner if battery costs prove to decline as quickly as other forecasts suggest. As the study concluded, "As more solar generation comes online, and solar curtailment and integration become more pressing challenges, storage can play a larger role by optimizing the use of solar generation and reducing the overall costs. Throughout many of our scenarios, by 2030, we find that Li-ion batteries can be cost-effective at much higher capacities (e.g., 5 GW of storage) and at longer durations (e.g., 4 hours)."[6]

These findings are relatively consistent with those of the alternative Duke Energy Integrated Resource Plan (IRP) developed by Synapse Energy

[6] **Exhibit 1**, p. 110.

OFFICIAL COPY

Jul 29 2019

Economics, which NCSEA filed in the current IRP proceeding.[7] That study used an advanced capacity expansion and production cost model (EnCompass) and demonstrated that elevated levels of solar-plus-storage, combined with demand side management and energy efficiency, would substantially reduce production costs while maintaining system reliability. Its modeling resulted in approximately 10,000 MW of total solar-plus-storage capacity by 2033.

Q. TO AVOID THE NEED FOR RECONCILIATION WITH EXISTING QF PPAS, CAN'T DEVELOPERS SIMPLY ADD SEPARATE, STANDALONE STORAGE TO THE GRID? OR DOES SOLAR-PLUS-STORAGE PROVIDE UNIQUE VALUE AS COMPARED TO STANDALONE STORAGE?

A. Solar-plus-storage provides several unique values over standalone storage, including but not limited to the following, which I summarize below:

a) Interconnection efficiency
b) Energy efficiency
c) Reduced solar clipping
d) Reduced solar curtailment
e) Monetization of federal tax credits

a. Interconnection efficiency

[7] *NCSEA Initial Comments*, Attachment 1 from Synapse Energy Economics entitled *North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan*, Commission Docket E-100 Sub 157, March 7, 2019.

OFFICIAL COPY

Jul 29 2019

Utilizing existing generator interconnections for the addition of energy storage, as opposed to requesting new generator interconnections for standalone storage, can be inherently valuable to the electrical system. Generator interconnections take up electrical loading capacity on the distribution and/or transmission system, whether those generators are operated at full output or not. In other words, for the purposes of interconnection studies, planning, and upgrades, the availability of electrical capacity on any given circuit or substation is determined by the volume of the installed and requested nameplate capacity of interconnected generators. Requiring separate, additional interconnection capacity for standalone storage equipment that in many cases could provide as much or more value as an addition to an existing generator interconnection is an inefficient use of the system's limited interconnection capacity – one that could result in unnecessary congestion and system upgrades at the expense of ratepayers.

b. Energy efficiency

Storing solar generation with on-site storage is inherently more energy-efficient than storing it with storage located elsewhere on the grid, due to the losses associated with the conversion, transmission and distribution (T&D) of the solar electricity. Bulk electricity storage requires that the electricity be in the form of direct current (DC). As such, energy efficiency gains are especially pronounced for DC-coupled storage located on-site behind the inverter of a solar power plant, which can store solar electricity directly

OFFICIAL COPY

Jul 29 2019

without requiring conversion to AC and back to DC, as required for storage anywhere beyond the facility's point of interconnection. Nevertheless, even AC-coupled storage located on-site with a solar plant carries an efficiency advantage, given its avoidance of losses from additional T&D.

c. *Reduced solar clipping*

Solar-plus-storage provides unique value by enabling the storage and utilization of solar generation that would otherwise be wasted due to clipping. To understand this value stream, it is useful to recall that solar facilities are regularly "oversized" in terms of their DC module array nameplate rating, in order to generate as close to the facility's full AC rating for more hours during the day, thus increasing the system's capacity factor and making its output more reliable. The ratio of the facility's DC to AC rating is often referred to as the "inverter loading ratio" (ILR) and has consistently grown over time for utility-scale projects as developers optimize system designs, reaching a new high of 1.32 in 2017 for U.S. utility-scale systems.[8]

As a result, when a facility's DC-side generation exceeds its AC capacity rating, the excess generation is "clipped." The volume of clipped power can range anywhere from around 2.5% of total potential production at lower ILRs, to as high as 10% at higher ILRs. The opportunity cost of this clipping is shouldered entirely by the facility owner, who is only compensated

[8] Lawrence Berkeley National Laboratory. "Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2018 Edition." 2018. *Available at* https://emp.lbl.gov/sites/default/files/lbnl_utility_scale_solar_2018_edition_report.pdf.

OFFICIAL COPY

Jul 29 2019

for the facility's AC output. Nevertheless, clipping represents a form of inefficiency and an opportunity cost for consumers to benefit from more clean, renewable power generation.

On-site storage is uniquely positioned to reduce solar clipping and turn wasted production into ratepayer value. Indeed, only on-site, DC-coupled storage equipment located behind the facility's inverter can take advantage of this opportunity. In a hypothetical example modeled in the NCSU Storage Study, a 3 MW/3 MWh DC-coupled battery added to a solar facility with an AC rating of 7.1 MW and a 1.4 ILR reduced solar clipping by at least 80% and significantly increased the share of time the facility generated maximum AC output, from 29% of the time without storage to 47% with storage. It is also worth noting that the NCSU Storage Study's headline conclusion that clipping is relatively uneconomical assumed minimal avoided cost rates that do not value the dispatchable nature of storage, particularly in terms of on-peak capacity and energy value during more granular on-peak periods.

d. Reduced solar curtailment

On-site storage can also mitigate the curtailment of solar production. Whereas clipped production is a cost shouldered solely by project owners, curtailed production is most often a cost shouldered by ratepayers. This is particularly true of qualifying facilities, which generally are only subject to curtailment in the case of system emergencies and otherwise must be compensated by the utility, in compliance with PURPA. While these events are infrequent,

OFFICIAL COPY

Jul 29 2019

especially as operational restrictions on other utility-owned generators are relaxed, on-site storage could nonetheless provide mitigation and enable the facilities to store production that would otherwise be lost.

This is also relevant for projects awarded under the Competitive Procurement for Renewable Energy program (CPRE). Only 2 of 14 awarded projects under CPRE Tranche 1 contained storage (and only 4 of 78 total bids), in part due to an avoided cost rate schedule that does not properly value storage,[9] and in part due to unreasonable operational restrictions imposed unilaterally by the utility in the Tranche 1 form Power Purchase Agreement (PPA). The Tranche 1 PPA allows for uncompensated economic curtailment of up to 10% of production in Duke Energy Progress (DEP) and up to 5% in Duke Energy Carolinas (DEC). Setting aside the merits of this curtailment provision,[10] it is worthwhile to note that on-site storage could reduce such curtailment, in similar fashion to the reduction of clipped production, and better enable the state to achieve its renewable procurement objectives under HB.589. As the cost of storage continues to decline, the owners of these CPRE Tranche 1 facilities (potentially including Duke Energy itself) may seek to add storage at a future date, particularly if operational restrictions are lifted.

e. Monetization of federal tax credits

---

[9] CPRE bids are structured based on the avoided cost rate schedule's defined on-peak and off-peak periods, which in part determine whether or not storage equipment is valuable and financeable.

[10] For more discussion on this topic, see the comments filed by NCCEBA in Commission Docket Nos. E-2, Sub 1159 and E-2, Sub 1156.

OFFICIAL COPY
Jul 29 2019

Finally, it is worth recalling that the federal investment tax credit (ITC) is only available to solar and solar-plus-storage generators. The ITC cannot be utilized for standalone storage, and in the case of solar-plus-storage, it can only be utilized when the storage equipment is charged predominantly with on-site solar generation. In other words, independent developers and ratepayers alike have a unique and time-limited opportunity to take advantage of the federal ITC through the installation of storage on solar generators. The ITC steps down to 26 percent in 2020, to 22 percent in 2021, and then to 10 percent permanently in 2022 for utility-scale systems, increasing the urgency to clarify our state's regulatory standards to enable market access for storage.

Q. **WHAT IMPLICATION DOES THE VALUE OF SOLAR-PLUS-STORAGE CARRY FOR THE SPECIFIC QUESTION AT HAND?**

A. The primary implication is that North Carolina ratepayers will benefit if barriers are removed to the addition of energy storage equipment to committed generators, including barriers related to the avoided cost rate schedule and contract terms and conditions. Independent power producers should not be prevented from utilizing storage equipment to enhance the value of their property and the state's solar resource base.

Q. **WHAT IS DUKE ENERGY'S POSITION ON THE ADDITION OF STORAGE TO COMMITTED GENERATORS?**

A. Duke Energy maintains that any committed QF that seeks to add storage must terminate its existing PPA (or LEO) and seek an entirely new PPA at current

OFFICIAL COPY

Jul 29 2019

avoided cost rates. In short, if implemented, the practical effect of this position will be to wholly obstruct the addition of energy storage resources to all operating QFs in North Carolina, and to most if not all committed pre-operational QFs. NCSEA submits that this is unfair, unreasonable, and bad policy, for the reasons discussed below.

As an initial matter, it is helpful to recall that the owners and operators of generating facilities – like the owners of many other types of infrastructure and other property – regularly seek to improve their property over its operating lifetime, and such improvements include investments to upgrade and replace equipment that necessarily modify the production profile of the facility. For example, the utility may invest in equipment that increases the ramp rate of one of its combustion turbines; it may install a control system that enables more flexible operation of a hydropower turbine; or it may seek to install environmental equipment on a coal unit in compliance with new federal regulatory standards that alters its output characteristics, among a wide range of other potential equipment upgrades.

In the case of a utility-scale solar generator, whether owned by the utility or an independent power producer, such investments are to be expected and encouraged over an asset's lifetime, including replacements and upgrades to degraded photovoltaic modules, tracking array equipment, inverters, and beyond. These replacements and upgrades often incorporate advancements in technology and know-how, and any of them can modify the production profile

OFFICIAL COPY

Jul 29 2019

of the facility. Indeed, even a modest adjustment in the angle of a solar array's physical orientation can change the facility's production profile. Routine modifications are inevitable and necessary and must be managed in a reasonable way. It is for this reason that section 1.5.2 of the North Carolina Interconnection Procedures allows for a variety of changes without triggering material modification, including changes or replacements of generators, inverters, solar panels, transformers, and relaying controls, and changes to the DC/AC ratio of a solar facility that does not increase the AC output capability.

Similarly, it would be unreasonable and unjust to obstruct equipment upgrades to generating facilities by imposing punitive measures for such upgrades via certain power purchase contract terms and conditions. Yet that is how Duke Energy treats the addition of storage to existing QFs. As Glen A. Snider testifies, "The Companies' position is that a 'committed' QF proposing to integrate battery storage should not be allowed to do so without the utility's consent (if a PPA exists) and, in all cases, should enter into a new or modified PPA at the Companies' then-current avoided cost rates."

In other words, Duke Energy seeks to terminate the PPA of any contracted qualifying facility if it attempts to add storage equipment, regardless of how the QF intends to utilize such equipment to enhance the value of the generator to the ratepayers – and then force the QF to recontract at the current negotiated QF PPA tenor of only five years if the QF is larger than 1 MW and ineligible for the standard offer. This is comparable to the

OFFICIAL COPY

Jul 29 2019

Commission revoking Duke Energy's ability to rate-base any number of its generating facilities if Duke Energy attempted to enhance those facilities for the benefit of ratepayers.

As a representative of one of the largest independent power producers in the region which seeks to invest in storage additions, I can attest that neither Cypress Creek nor any QF owner of which I am aware will invest in storage if the QF is subjected to such commercially unreasonable conditions.

Q. IS DUKE ENERGY'S POSITION CONSISTENT WITH EXISTING STANDARD OFFER AND NEGOTIATED PPAs?

A. No. To my knowledge there is nothing in the standard offers terms and conditions, nor in Cypress Creek's negotiated QF PPAs, that prohibit the QF from making equipment changes that change the schedule of output, as is the primary intent of storage equipment. Nor is there anything in the standard offer QF PPA that prohibits, or requires Duke Energy's consent for, equipment changes. Section 8(e) provides that where equipment changes are made, Duke Energy should be given sufficient notice to review them to ensure that they will not compromise the safe operation of the facility. That is the only consideration recognized in the standard offer QF PPA. Thus, what Duke is proposing here is a significant change to the current standard offer.

Q. WHY MIGHT THE UTILITY ATTEMPT TO OBSTRUCT ADDITIONS OF STORAGE TO COMMITTED FACILITIES?

OFFICIAL COPY

Jul 29 2019

A. Among the most consistent messages this Commission hears from Duke Energy today regarding variable renewable power in general, and solar in particular, is that its intermittency and non-dispatchability makes it a less valuable resource and imposes integration costs on Duke's system. As just one example, Snider testifies in this proceeding that "the Companies have determined that the costs avoided by growing levels of solar QFs that provide intermittent, non-dispatchable power is markedly different from integrating firm power and that it is appropriate to recognize integration costs in valuing the energy and capacity provided by QFs… ."[11] Similarly, Duke Energy claims that it is approaching an excess level of solar penetration that requires growing levels of curtailment.

One would therefore assume that Duke Energy is eager to accelerate the deployment of energy storage equipment on committed solar generators to enable greater dispatchability and to shift production to periods when it is most valuable to Duke Energy's customers. In reality, however, as demonstrated by Duke's positions on the PPA terms and conditions and the interconnection standards, its orientation toward energy storage additions can at best be characterized as reluctant, and at worst as obstructive.

Duke Energy's primary justification for its position is that it seeks to prevent QFs from attempting "to integrate battery storage systems or any other technology that materially alters a QF's energy output or shifts power

[11] *Direct Testimony of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Commission Docket No. E-100, Sub 158, May 21, 2019, p. 34.

OFFICIAL COPY
Jul 29 2019

production under stale, legacy avoided cost rates… ." It is unclear how Duke Energy is defining "materially alter" in this context with respect to the facility's production profile and whether it will attempt to terminate PPAs for QFs that make routine equipment upgrades that affect its production profile. It is worth querying whether Duke Energy similarly anticipates terminating the PPAs of CPRE awardees which may attempt similar facility upgrades in the future, including battery storage.

More broadly, it is appropriate to briefly address Duke Energy's characterization of the state's solar resource base as relying on "stale, legacy avoided cost rates." First, the avoided cost rates at which those QFs contracted at the time were based on an avoided cost methodology that was approved by the Commission and determined to be in the ratepayer interest. Second, a key driver of today's lower avoided cost rates is the reduction in capacity costs due to the existing capacity of those very QFs; that is to say, the absence of those QFs would likely drive up avoided capacity rates. Third, the recent reduction in Duke's energy rates based on record-low natural gas prices is likely to be a temporary phenomenon due to the likelihood of federal regulatory standards, within the tenor of these QF PPAs, to address the negative environmental externalities of natural gas extraction, transportation, and electric power production.

Fourth, and most fundamentally, Duke's existing business model as a regulated utility depends in significant part on the existence of "stale" rates

OFFICIAL COPY

Jul 29 2019

available to its own generating units via multi-decade cost recovery in the rate base. Duke will similarly benefit from 20-year CPRE PPAs for its awarded facilities based on bid prices established while the cost of photovoltaic modules continues to decline, and while future energy and capacity rates remain inherently uncertain, especially two decades into the future. It is inherent market uncertainties of this kind that at times leads utilities to abandon large-scale development projects despite exorbitant up-front expenditures, such as SCANA Corporation's abandonment of VC Summer Units 2 and 3 in 2017 following the expenditure of approximately $9 billion, and such as Duke Energy's abandonment of the Lee Nuclear Station in 2017 following the expenditure of $541 million, a sum that will be passed on ratepayers. To say that there are risks to ratepayers related to "stale" rates being incurred by successfully constructed and operating solar QFs on existing PPAs that then become adopted by added storage equipment, in relatively limited scope, ignores the repeated risks utilities take that are financially shouldered by ratepayers. Unlike the cancelled projects described above that will never generate a kilowatt hour of electricity for ratepayers, the addition of storage to existing QFs provides a valuable asset that can be utilized both during the remainder of the QF's existing contract, as well as in subsequent PPAs with the utilities.

Financing any large capital investment requires long-term contracted cash flows, especially in the power sector, and the establishment of long-term

OFFICIAL COPY

Jul 29 2019

contracts always entails uncertainty about future market prices. Regulated utilities understand this better than most corporations, because their business model depends on their ability to recover the cost of their invested capital over an extended period of time (their cost recovery term), without which they could not construct a single power plant.

For these reasons, it is unclear whether Duke Energy's position on storage additions is primarily related to its concern about "stale" rates, especially since storage additions would mitigate the very concerns that Duke expresses about the non-dispatchability of North Carolina's solar fleet. And as discussed further below, implementation of NCSEA's compromise position on applicable rates and terms for storage would actually reduce the amount of energy and capacity being sold under those "stale" rates, in favor of output delivery at updated rates during periods of high demand. What we do know is that Duke has explicitly expressed its objective to rate-base approximately $500 million in batteries in the Carolinas, as indicated in its 2018 Integrated Resource Plan[12] and in its public communications[13]. It appears that Duke would prefer to self-build and rate-base these assets, rather than enable storage market access for competing independent power producers.

[12] *See* Duke Energy Carolinas and Duke Energy Progress. 2018 Integrated Resource Plan and 2018 REPS Compliance Plans, Commission Docket E-100, Sub 157, September 5, 2018.
[13] Duke Energy. "Duke Energy to invest $500 million in battery storage in the Carolinas over the next 15 years." Press Release. October 10, 2018. *Available at* https://news.duke-energy.com/releases/duke-energy-to-invest-500-million-in-battery-storage-in-the-carolinas-over-the-next-15-years.

Q. **DOMINION WITNESS BILLINGSLEY ARGUES THAT A QF WITH A LEO UNDER THE SUB 136 OR SUB 140 TARIFF SHOULD NOT BE ABLE TO DEVIATE FROM THE CONFIGURATION OR OUTPUT SPECIFIED IN ITS CPCN OR FERC FORM 556 WITHOUT LOSING ITS LEO. DO YOU AGREE WITH THIS?**

A. No. The logic of Dominion's argument is not entirely clear, but the company seems to argue that the representations in a QF's Form 556 and Certificate of Public Convenience and Necessity ("CPCN") when the LEO is established somehow become enforceable terms of the QF's PPA. This is incorrect for several reasons. First, when a QF enters into a PPA, the terms of that contract supersede the terms of any LEO previously established as a matter of law. 18 C.F.R. § 292.304. Any constraints on the project's configuration and output come from the terms of the PPA. And as discussed previously in my testimony, the addition of storage does not violate the terms of the utilities' standard offer PPAs.

Dominion's argument that the details contained in a CPCN application (the CPCN itself includes information only about the location and nameplate capacity of the facility) become enforceable terms of its PPA is inconsistent with the purpose for which the Commission decided to include the CPCN as an element of the LEO test. The reason the Commission incorporated the CPCN requirement into the North Carolina LEO test was to ensure that QFs "would be in a position to enter into a legally enforceable obligation" before

OFFICIAL COPY
Jul 29 2019

a LEO can be established, "and that requires a certificate." Order on Pending Motions, Docket No. E-100, Sub 74 (Feb. 13, 1995) at 3. The CPCN requirement was not intended to "lock" QFs in to the facility exactly as described in the CPCN application.

Similarly, the Commission decided to require a developer to self-certify as a QF prior to obtaining a LEO simply to avoid disputes over LEO dates, and "to provide a standardized and clearly stated method to establish an LEO." Order Establishing Standard Rates And Contract Terms For Qualifying Facilities, Docket No. E-100, Sub 140 (Dec. 17, 2015) at 52. Again, the Commission did not say or even suggest that the information on the Form 556 should become an enforceable term of its PPA or LEO.

Of course, if a QF changes its facility such that the information in its CPCN and/or Form 556 is materially inaccurate, it must file an updated Form 556 and inform the Commission, which may decide that an amendment to the CPCN is necessary. The Commission has approved hundreds of such amendments. But it has never held (and to my knowledge no party has ever argued) that a CPCN amendment or a Form 556 recertification voids any LEO that was established on the basis of those certifications. Under Dominion's reasoning, though, each of those projects would have lost its LEO and/or breached its PPA.

OFFICIAL COPY

Jul 29 2019

Q. WHAT AVOIDED RATE SCHEDULE AND CONTRACT TERMS AND CONDITIONS SHOULD APPLY WHEN A QF ADDS STORAGE TO A GENERATING FACILITY?

A. The addition of storage to committed QFs is an innately productive equipment upgrade – similar in nature to other equipment upgrades that may adjust a generating facility's production profile – which enhances the value of the asset and is consistent with existing standard offer and negotiated QF PPAs. NCSEA believes this issue may be left to the interconnection standard, rather than a Commission ruling.

However, to the extent the Commission rules on this specific question, NCSEA does not view it as inconsistent with ratepayer interest to allow a QF to install and operate storage equipment as with other equipment upgrades, per the terms and conditions of its existing PPA, if the QF is approved to add storage per the interconnection standard. However, in service of reaching agreement with Public Staff and the utilities to clarify the issue and enable storage market access, NCSEA supports a compromise position.

Under NCSEA's proposed compromise approach, if a QF seeks to add energy storage to a committed generating facility, and if that storage addition is approved via the interconnection standard, the output from that storage equipment would be eligible for the then-available avoided cost rate schedule. In this scenario, the storage equipment would not represent a new QF, but instead would constitute an equipment change accompanied by a revision to

OFFICIAL COPY

Jul 29 2019

the existing QF PPA, with the PPA revision limited to the accommodation of the storage equipment. The revised PPA would maintain the remainder of the original PPA's terms and conditions, including the remaining PPA tenor. The remaining PPA tenor would be available to the output of the facility's existing generation equipment and to the additional storage equipment. This would apply to QFs that have executed a PPA or commenced operation. In the scenario of a QF that has established a LEO but has not executed a PPA, the same PPA treatment would apply: if that QF seeks to add storage as approved via the interconnection standard, the QF's storage equipment would be eligible for the then-current avoided cost rate schedule, for a PPA tenor equivalent to the avoided cost rate schedule of its original LEO.

This compromise is similar to the approach suggested by the Public Staff in this proceeding. In its Initial Statement, the Public Staff wrote, "The Public Staff suggests that one approach to balance the need to incentivize new technologies with establishing appropriate rates would be to separately meter any additional energy output from the original facility and compensate the additional output at the then-current Commission approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of its pre-existing PPA. … If it is feasible to separately meter or otherwise estimate the incremental energy output from the modification to the facility, the Public Staff believes the QF should request to amend its existing PPA for

146

OFFICIAL COPY

Jul 29 2019

increased DC output and should not be required to enter into a new PPA for the entire facility."[14]

In practical terms, to implement this approach the Commission could order that existing standard offer QF PPAs and negotiated QF PPAs shall be modified to incorporate storage upon election by an interconnection customer, with the storage equipment's output subject to the most recent Commission-approved avoided cost rate schedule. For storage additions to standard offer QF PPAs, the Commission would approve standard storage PPA language. For negotiated QF PPAs, commercially reasonable terms and conditions would be negotiated.

An essential element of this compromise approach regards the tenor of the avoided cost rate available to the output of the storage equipment. As discussed throughout this testimony, and as identified specifically by the NCSU Storage Study attached here as **Exhibit 1**, one of the most significant values of storage is the deferral of peak capacity. As the Study noted in its final conclusion, "A very important driver for energy storage is the capacity value and the technology's ability to displace new generation investments."[15] Under this compromise approach, the only arrangement that could potentially enable storage to provide such value to ratepayers – and thus the only arrangement that would enable a QF a reasonable opportunity to attract private

[14] *Initial Statement of the Public Staff*, Commission Docket No. E-100, Sub 158, February 12, 2019, pp. 75-76.
[15] **Exhibit 1**, p. 114.

OFFICIAL COPY

Jul 29 2019

capital to finance a storage addition – is if the rate available to its output is set, at minimum, to the 10-year avoided cost rate (assuming at least 10 years of the QF's PPA schedule remains). Since the vast majority of the utility's identified capacity need is beyond 5 years, only a 10-year avoided cost rate at minimum will represent that capacity value and make it available to the storage equipment. In other words, if the utility attempted to limit the avoided cost rate tenor available to the storage equipment to only 5 years, that avoided cost rate would not reflect the value of peak capacity deferral in the utility's IRP. A 5-year avoided cost rate would therefore undercut or fully eliminate the capacity value of the storage equipment and make it wholly unfinanceable.

Q. IF THESE RECOMMENDATIONS ARE ADOPTED, DO YOU EXPECT TO SEE STORAGE ADDITIONS TO COMMITTED QFs?

A. Even if these recommended avoided cost rate and contract terms and conditions for storage additions are adopted, it is unclear whether the utilities' pre-existing and forthcoming avoided cost rate schedules sufficiently value the resource to enable deployment. Interconnection also remains a critical barrier to market entry, as discussed thoroughly in both the CPRE docket and the interconnection standards docket.[16] In general, battery storage remains a nascent technology. However, it is an imperative technology and requires intentional regulatory support to enable its initial market entry and scale-up.

[16] *See generally* NCSEA and NCCEBA's (and other intervenors') comments filed in the Interconnection Standard Docket (Commission Docket No. E-100, Sub 101) and the CPRE Program Plan Docket (Commission Docket Nos. E-2, Sub 1159 & E-7, Sub 1156).

OFFICIAL COPY

Jul 29 2019

In recognition of this dynamic, several U.S. states have adopted more proactive measures to promote energy storage adoption, a variety of which are discussed in the NCSU Storage Study.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

OFFICIAL COPY

Jul 29 2019

BY MR. SMITH:
Q Mr. Norris, did you prepare a summary of your testimony?
A I did.
Q All right. Thank you. Can you please read that now?
A Yes. Commissioners, thank you for the opportunity to testify before you today. My name is Tyler Norris, and I am a Director at Cypress Creek Renewables, where I lead the company's development in the Southeast. I'm appearing here on behalf of NCSEA.

The purpose of my testimony is to respond to the Commission's Order of June 14th, 2019, requesting testimony on the topic of energy storage additions to electrical generating facilities. Specifically, that Order requested testimony to address what avoided cost rate schedule and contract terms and conditions should apply when a qualifying facility adds storage equipment to an operational facility or to a QF with an executed -- and executed PPA and/or LEO, which I refer to collectively as "committed generators."

My testimony is organized into three sections. The first section addresses the broader significance of market access for energy storage and the potential value

OFFICIAL COPY

Jul 29 2019

of storage additions to committed solar generators. After establishing the potential value of solar plus storage resources, I discuss the positions of the Utilities, as presented in their supplemental testimony, and the implications of those positions for the deployment of storage in North Carolina. Finally, I provide a recommendation on how to approach the specific question posed by the Order.

To address that question, the first and foremost consideration is what is allowable under the standard offer PPA. And as my testimony explains, there is nothing in the standard offer terms and conditions that prohibits a QF from making equipment changes that change the schedule of the output. Furthermore, there is nothing in the standard offer QF PPA that prohibits or requires the Utility's consent for equipment changes. Rather, the PPA only provides that the Utility be given sufficient notice to review such equipment changes to ensure that they will not compromise the safe operation of the facility. That is the only consideration recognized in the PPA. And as such, it is the view of NCSEA that committed generators are fully entitled to add storage under the terms and conditions of the standard offer PPA, including the applicable PPA rate structure

OFFICIAL COPY

Jul 29 2019

and tenor.

Nevertheless, NCSEA has offered a significant concession. In the spirit of reaching an agreement with the Public Staff and to accommodate interest in maximizing ratepayer value, NCSEA has offered to accept an alternative arrangement in which the output from the storage equipment that is added to a committed generator would be eligible for the most recently available avoided cost rate. In this scenario the storage equipment would not represent a new QF, but would constitute an equipment change accompanied by a revision to the existing QF PPA. The revised PPA would maintain the remainder of the original PPA's terms and conditions, including its PPA rate structure and tenor, which would be available to the output of the facility's existing generation equipment and to the added storage equipment. The only material difference between the terms of the original PPA and the modified PPA regards the addition of the storage and how stored energy will be compensated when dispatched onto the system.

Although they and their members have no obligation to do so, NCSEA and NCCEBA are willing to make this significant concession in the interest of achieving an amicable resolution of the issue. However, if the

OFFICIAL COPY

Jul 29 2019

Utilities will not accept this concession, then NCSEA maintains its view on the contractual rights of QFs to add storage equipment under the standard offer PPA and utilize the proportionate avoided cost rate vintage for that PPA.

Unfortunately, Duke Energy has articulated an uncompromising position in which any committed generator that adds storage must terminate its existing PPA, or LEO, and seek an entirely new PPA. The practical effect of this position would be to wholly obstruct the addition of storage resources so the vast majority of renewable generators, despite the fact that a primary purpose of these resources is to mitigate the very concerns that Duke expresses about their intermittent and nondispatchable nature. NCSEA believes that this position is unreasonable, unjust, and bad public policy, and that it should be rejected.

My testimony discusses a variety of ways in which ratepayers can benefit if such barriers are removed to the addition of storage equipment to renewable generators, including bulk energy time shifting, peak capacity deferral, interconnection efficiency, reduced solar curtailment and more, as analyzed in much greater detail in the NC State University storage study which was

OFFICIAL COPY

Jul 29 2019

required by HB 589 and attached as Exhibit A. Storage can enable existing solar generators to become more dispatchable, storing generation in off-peak periods when it is needed less, or at times when that generation would otherwise be clipped or curtailed altogether, and instead discharging onto the grid when the output is needed most and provides greater ratepayer value. In turn, this solar plus storage resource can help avoid the cost of new peaking capacity. In fact, NC State study concluded that bulk energy time shifting and peak capacity deferral alone may prove cost effective for up to 5,000 MW of lithium-ion batteries by 2030.

As my testimony discusses, these findings are generally consistent with those of the alternative Duke Energy Integrated Resource Plan developed by Synapse Energy Economics which NCSEA filed in the recent IRP proceeding. And that study used an advanced capacity expansion of production cost model and demonstrated that elevated levels of solar plus storage, combined with demand-side management and energy efficiency, would substantially reduce production costs, while maintaining system reliability. Its modeling resulted in approximately 10,000 MW of total solar plus storage capacity by 2033.

OFFICIAL COPY

Jul 29 2019

NCSEA acknowledges that Duke sees similar value in energy storage, based on the proposal and its latest Integrated Resource Plan to self build and rate base approximately $500,000,000 in battery storage projects. However, NCSEA submits that ratepayers will substantially benefit if independent power producers and existing generators were allowed to compete and utilize storage resources instead of authorizing the Utility to obstruct market access. By affirming the contractual right of committed generators to add storage equipment, this Commission can take a meaningful step in that direction.

Thank you again for this opportunity, and I look forward to your questions.

MR. SMITH: Madam Chair, NCSEA Witness Tyler Norris is available for cross examination.

CHAIR MITCHELL: Thank you, Mr. Smith.

MR. SMITH: I think there's another on this side of the table.

CHAIR MITCHELL: Okay. Thank you.

CROSS EXAMINATION BY MR. BREITSCHWERDT:

Q Good afternoon, Mr. Norris. Brett Breitschwerdt on behalf of Duke Energy. How are you?

A Good. Thank you.

Q Good to see you. All right. So your summary

OFFICIAL COPY

Jul 29 2019

elucidated a lot of the points in your testimony, and I think I want to start out with this concept of a concession that -- or a compromise, as NCSEA has proposed it, and you've used the word a number of times, the concession that you're making. And if I understand it correctly, the concession is that NCSEA takes the position that independent power producers, committed solar generators have the right under the current standard offer to make -- to add storage -- we can talk in a little bit about what's an equipment change -- but to add battery storage to an existing QF; is that correct?

A Yes. That's correct. And just to elaborate, if we look specifically at section 8(e) of the Terms and Conditions of the standard offer PPA, you can see clearly that it only requires the seller to notify the Company of any -- of any changes to their generation system, including various equipment, and only shall provide the Company adequate time to review such changes to "ensure continued safe interconnection" prior to implementation. So it is NCSEA's view that the standard offer PPA does not do anything to limit the ability of the generator to -- to change or add equipment that would change the -- the production profile or the scheduling of the output.

OFFICIAL COPY

Jul 29 2019

And so that is NCSEA's position.

Q Thank you. And just -- Cypress Creek, largest solar developer in the state; is that accurate?

A In terms of installed total number of MW developed in North Carolina, that is correct, to our understanding.

Q And how many projects are under your ownership or operational control today?

A My understanding, subject to check, is that approximately 1,000 MW of projects are currently owned by Cypress Creek in the state of North Carolina.

Q So most of them 5 MW, so somewhere between 80 and 100 projects; is that -- am I doing the math appropriately?

A A substantial portion of the projects on a project count basis are standard offer QFs between 2 to 5 MW each.

Q Okay. So can we say about 80 projects, just roughly; is that fair?

A Approximately.

Q Okay. So of those 80 projects, how many has Cypress Creek unilaterally taken the step of adding battery storage or making an equipment change, as you articulate is clearly allowed under the standard offer

OFFICIAL COPY

Jul 29 2019

PPA since those projects went commercially operational?

A In fact, I would note that Cypress Creek has attempted to add storage equipment to either an operational or a committed generator, subject to check, and, in fact, has been obstructed in its ability to do so due to the interconnection standard, which is a subject of another proceeding, but which is also a substantial barrier to the addition and interconnection of storage to committed generators. So in Cypress Creek's attempt to do so, it has encountered that obstruction. We did not even have a chance to encounter or to discuss the issue of impact on the PPA, to my knowledge.

Q So just to be clear, your obstruction is you went to the Utility and they said is it a material modification, and the Utility said, yes, it's a material modification, so you had to submit a new interconnection request; is that correct?

A Cypress Creek, in that instance, elected not to submit an interconnection request because it would put that interconnection request at the bottom of the queue, and it takes multiple years at this point to process the queue. So the notion of forcing an added storage device to go to the bottom of the queue effectively kills that -- that project's prospect.

OFFICIAL COPY

Jul 29 2019

Q So maybe another way to characterize this obstruction is Duke Energy followed the North Carolina interconnection standards, evaluated this storage addition, determined it was a material modification and said, sure, you can add storage, but you have to submit a new interconnection request; is that fair?

A It is fair that Duke unilaterally, at the time, made that determination. It was a subject of substantial debate in the recent interconnection proceeding. While NCSEA and NCCEBA disagree with the determination that a storage device operating within hours already studied under the system impact study should constitute a material modification, we accept the Commission's ruling on that specific issue. However, it is critical that we do move forward with an expedited study process that would allow an expedited review of those storage additions and allow them to interconnect. And so I would just note that we, in general, agree that this matter can primarily be left to the interconnection standard, and I think we can reach amicable resolution on that expedited study process with Duke, and we look forward to doing that.

Q So I'm going to go back to my original question. So how many projects has Cypress Creek

OFFICIAL COPY

Jul 29 2019

materially altered by adding storage or overpaneling or adding equipment since the project became commercially operational, since you have the unilateral right to do so under NCSEA's position? Is the answer zero?

A The answer with respect to storage, to my knowledge, is zero. And I would note as well that until recently, storage has perhaps not been at a cost point at which it would have been feasible to -- to add it to even a prior rate structure. With respect to the other equipment changes you mentioned, there certainly have been various equipment changes. Some of them have been replacements due to damage, such as some minor damage that occurred in last year's hurricane.

In some cases there was wear and tear on different inverters or other modules that have been replaced, and in some cases those modules or even those inverters may have, in fact, been so outdated that they required an upgraded version. And so this happens quite often. You, you know, use a vintage of a certain inverter or module or other equipment at a certain prior date when the system was installed, some wear and tear occurs, there is some other damage, and you may have to replace it, actually, with an updated model that may have slightly different operational characteristics, some of

OFFICIAL COPY

Jul 29 2019

which can, in fact, affect the production profile of the system. And I imagine that the same is quite true of the Utility's many, many generators and may other independent power producers as well.

Q So it sounds from what -- like what you just said, and tell me if I'm not characterizing this correctly, you've made repairs, you've replaced equipment when there's damage, and there may be some minor increase in DC capacity in those circumstances, some upgrade to equipment, but you've not gone out and unilaterally increased the AC to DC ratio -- or the DC to AC ratio by, you know, from 1.2 to 1.5; is that correct?

A I --

Q It's a yes or no question, please.

A Well, I want to be very accurate here. There may have, in fact, been equipment changes or changes to modules, or even in some cases addition of modules to increase the DC capacity; however, certainly, to my knowledge, there has not been an addition of the storage equipment to change the DC rating in the manner you described.

Q So Cypress Creek has not materially altered a facility, as it's defined in the new Terms and Conditions, either through adding storage or otherwise,

OFFICIAL COPY

Jul 29 2019

that's not a -- a like-kind change. That's the concept that Duke has said, yes, that's reasonable. You can make repairs, replacements, but if you're going to materially alter the facility, then that's something that you need to have the Utility's consent and you need to obtain approval, and that is a more significant materially altered facility.

MR. SMITH: I'm going to -- I'm going to object. There's a compound question. Could you break that up, please?

MR. BREITSCHWERDT: Sure.

Q To be clear, has Cypress Creek materially altered a facility by either increasing the DC to AC capacity versus just making a like kind equipment change? And if so, did you get a material modification from the Commission --

A Ability --

Q -- from the Utility to do so?

A Thank you. I think it's critical that we do distinguish two different issues here. One is the interconnection standard and what qualifies as a material modification for interconnection. And so that's a distinct issue and we can discuss that, but that's been addressed in a separate proceeding, and that's what we're

OFFICIAL COPY

Jul 29 2019

going to move forward on an expedited study process. With respect to the PPA, there is a different standard by which there is, say, what Duke has characterized as a material alteration.

It's very clear, in -- in reviewing the PPA and based on the very clear guidance of our counsel, that the standard offer QF PPA does not prohibit a QF from making equipment changes that change the schedule of the output, and that there is nothing that requires the Utility's consent for equipment changes in general. And so I leave it ultimately to our attorneys to sit down and look together at the PPA's language, but that is -- that is my clear understanding of -- of the PPA's terms and conditions.

And so I -- my understanding is that there have been, in a variety of instances, equipment changes that have occurred that have not affected the PPA, but for the reasons I've explained, that has not been tested on storage because to date we have not even been able to get beyond the interconnection standard issue.

Q And so at these facilities where you've replaced panels, you've increased -- well, is it fair to say that you've also increased the -- and you've increased the DC to AC capacity. Have you increased the

OFFICIAL COPY

Jul 29 2019

ratio in such a way that more MWh were sold to customers from that facility?

A There may have been a case where a modification resulted in an increase in the DC rating, and that could have even resulted from, again, replacing a module that was -- was an expired module type and upgraded to a more updated module type. And -- and this has been occurring across the country, by the way. The average DC to AC ratio for utility scale solar systems has been increasing every year for the past decade as -- as these project operators optimize system designs, and there are substantial benefits, in our view, that come from that because it actually addresses one of the -- the concerns expressed by the Utility, which is that you may not be operating the facility at a steady and maximum level of output, that you may be experiencing intermittency, but actually by slightly oversizing the DC side of the system, you may end up with a smoother and more steady and reliable production profile. So in our view, in fact, there is a healthy DC to AC ratio that is in the interest of even reducing and avoiding some of the integration costs that are being discussed here.

Q Well, let me -- and will you accept, subject to check, that this is language from the Terms and

OFFICIAL COPY

Jul 29 2019

Conditions? But I just want to be clear, as Mr. Wheeler testified to on behalf of Duke Energy, Section 4(b) of the Terms and Conditions provides that Seller shall not change his contract estimated annual kWh energy production without adequate notice to the Company and without receiving the Company's consent. Is it your position that under this same standard offer PPA, you have the right to materially change the facility --

MR. SMITH: I'm going to object. I believe materially change the facility is the legal conclusion at issue, and he's asking a question that requires a legal conclusion to an expert on storage, not on that legal conclusion.

THE WITNESS: Thank you. I --

MR. BREITSCHWERDT: He's speaking to the Terms and Conditions of the PPA.

MR. SMITH: No, no. You used the term materially changed, and that's the issue.

MR. BREITSCHWERDT: Okay. Well, it says shall not change in such a manner that without -- in such a manner that increases the contracted estimated annual energy kWh production.

Q And I'm just trying to establish that in the prior course of dealing between Duke Energy and Cypress

OFFICIAL COPY

Jul 29 2019

Creek, you have not, in fact, done that or that would have required the Utility's consent. Would you agree with that?

MR. SMITH: I'm going to object. I feel like we've been over this once and again about how many times they've done it, and -- and at this point are we -- I guess I'm asking you to ask that one more time in a way that doesn't require him to -- to go backwards to what he was saying and then go forwards into a legal conclusion related to it.

A I'm happy to --

CHAIR MITCHELL: I'm going to let Mr. Norris answer the question. We recognize that he's not a lawyer, but let's -- let's get the question out and let's give him an opportunity to answer.

MR. BREITSCHWERDT: Yes, ma'am.

CHAIR MITCHELL: Thank you. We'll move on.

A So the -- the --

CHAIR MITCHELL: Mr. Norris, let's let Mr. Breitschwerdt ask the question again so it's clear on the record.

Q So it's clear on the record, I'm just trying to establish the course of dealing between the Utility and a QF facility and the provisions of the Section 4(b) of the

OFFICIAL COPY

Jul 29 2019

Terms and Conditions provide that the Seller, meaning the QF, shall not change its contracted estimated annual kWh energy production without adequate notice to the Company and without receiving the Company's consent. And I'm trying to confirm that you have not, in fact, done that.

A So the -- the broader question that's being raised here --

Q It's a yes or no question --

A -- and I think the point that is being drawn out is --

Q -- Mr. Norris.

A -- whether a storage addition may increase the estimated annual generation of a facility. I'm not in a position to address the specific question of -- of prior contractual dealings or discussions with the Utility on specific projects, but the point I believe he's driving at is what are the implications for the annual estimated generation, which is a data point that is included in the PPA, and at the end of the day, I'd leave it to the attorneys to figure out a -- first of all, what is an allowable deviation from that estimated generation because it is, of course, an estimate.

But it is -- it is separate from the consideration before us, because the addition of a

OFFICIAL COPY

Jul 29 2019

storage device does not even necessarily increase the estimated annual generation. It's possible it could, but it doesn't inherently do so, and I just want to give the Commission a clear example. So in the updated avoided cost rate schedule --

MR. BREITSCHWERDT: Madam Chair, I asked a simple yes or no question, and we've now been --

MR. SMITH: Mr. -- we had two-minute long answers yesterday, and I --

CHAIR MITCHELL: Well, Mr. Smith --

MR. SMITH: Yes.

CHAIR MITCHELL: -- let's let Mr. Breitschwerdt get through his objection. I'm going to remind you all one more time, for the purposes of court reporting, do not talk over each other. Let's go one at a time. Mr. Breitschwerdt, what is your objection?

MR. BREITSCHWERDT: My objection is I asked a yes or no question, and we're now two minutes into the answer.

CHAIR MITCHELL: And?

MR. BREITSCHWERDT: And I think that I should have a right to the yes or no question, and I was trying to interject to establish that point.

CHAIR MITCHELL: Thank you. Do you -- do you

OFFICIAL COPY

Jul 29 2019

have a response to Mr. Breitschwerdt's objection?

MR. SMITH: That's not a legal objection.

CHAIR MITCHELL: Mr. Norris, please do your best to answer -- to get -- to make your point concisely, and stick to answering the questions that Mr. Breitschwerdt asks. Thank you.

THE WITNESS: Okay.

A I'll just wrap this up very briefly, and it's just the point that in the avoided cost rate structure that the Utility has proposed, the on-peak capacity hours are, say, in winter mornings, and the overall solar facility generation of wintertime is that it can be substantially less than the AC rating. And so in that instance, if you were utilizing a battery, the time-shift production to the on-peak capacity period that has been indicated by the Utility, you would not very likely see any increase in estimated annual generation, while still providing ratepayer value. And so we just wanted to clarify that it doesn't necessarily result in estimated increase -- sorry -- an increase in the estimated annual generation.

Q I'm going to move on. So ratepayer value, throughout your testimony you speak to benefiting ratepayers or enhancing the value of the generator to the

OFFICIAL COPY

Jul 29 2019

ratepayers, but while your testimony generally speaks to the capabilities of storage, it doesn't provide for any specific cost savings or operational benefits to customers of adding storage to an existing QF; is that correct?

A The testimony itself does not cite specific figures; however, the exhibit, I believe, provides a variety of estimates on the value that could be provided to ratepayers through energy storage resources in North Carolina and to Duke's system.

Q "Could be provided," so that's premised upon some contractual right of the Utility to obtain those benefits or some economic signal that would promote the storage to operate in a way that would benefit customers; would you agree with that?

A I would agree with that statement, and I would add that part of the challenge is that we currently are unable to provide those benefits to the system that were identified in the study in many cases because of the exact obstacles that we are discussing here today.

Q And were you here for Mr. Snider's testimony, where he was speaking about the indifference principle and the concept of the value of PURPA power?

A I was. And can I elaborate on that point, or

OFFICIAL COPY

Jul 29 2019

are you just confirming that I overheard it?

Q I -- if you'd like to respond, please.

A Okay. Sure. Well, I just recall, I believe, what Mr. Snyder was stating at that time is that -- what he was saying is that even in the scenario where the output of a battery added to an existing generator was put on to the updated avoided cost rate, as approved by this Commission, his point was that in that instance, it doesn't really provide ratepayer value. It would only hold them indifferent.

And I want to discuss this because it is, actually, a really important issue. First and foremost, from -- there are many values that, in fact, we believe the QF provides over the addition of, say, a new peaking capacity unit to provide capacity value, and one of those values that I discuss in the testimony, in fact, is interconnection efficiency, that if you're able to meet a capacity need by adding a battery to an existing generator without requiring a new interconnection request and by using limited interconnection capacity available on the transmission or distribution system, it's a more efficient use of the system's overall interconnection capacity, and it may mitigate the need for network upgrades or other upgrades to the transmission and

OFFICIAL COPY

Jul 29 2019

distribution system, and it also would mitigate the potential for any additional unneeded congestion on the system.

So in our view, just from that alone, it undermines that point of indifference. But beyond that, in addition -- I mean, you have to go and build an entirely new peaking facility. It requires land, it requires a whole range of approvals, entails a whole range of transactional cost. And then a third point I would make is that I believe the United States federal government has determined that in the instance of a QF versus a utility-owned non-QF generator, if all else is held equal, including the rates, that it is the requirement and the preference of the federal government that the utility be required to procure that capacity and energy from the QF. And so for those three reasons alone, in addition to others I believe we could discuss, we do not accept the premise of an indifference principle in that specific scenario.

Q So we can go back and forth on what encouragement means under federal law, but would you agree with me that in North Carolina we've established, through House Bill 589, the implementation of PURPA?

MR. SMITH: I'm going to object. It calls for

OFFICIAL COPY

Jul 29 2019

a legal conclusion, and he's not an attorney.

MR. BREITSCHWERDT: He just extensively spoke to his perspective on federal law and the process -- Madam Chair --

CHAIR MITCHELL: Mr. Norris, you can answer the question. We recognize that he is not a lawyer. So please answer the question.

A I understand that HB 589 was an interpreta--- North Carolina state interpretation of PURPA implementation in the state.

Q That's right. And through that process, North Carolina established the framework for adding additional renewable generation to the system and determined that there would be a traditional PURPA implementation framework and then a competitive procurement framework; is that correct?

A That is correct.

Q Okay. And through that competitive procurement framework new resources can be added that are more beneficial than through traditional PURPA in terms of cost savings to customers, in terms of procuring environmental attributes, and in terms of obtaining enhanced dispatch to the Utility. Would you agree with that?

OFFICIAL COPY

Jul 29 2019

A I agree that competitive procurement can result in cost savings to ratepayers below the avoided cost rate.

Q And enhanced operational control?

A Per the terms of the current PPAs, they do provide for additional operational control.

Q And the renewable attributes associated with those facilities?

A That's correct.

Q And so additional benefits that are distinct from traditional PURPA?

A I would question the characterization necessarily that all those are distinct benefits, but I think you could point to one or two of them that maybe characterizes benefits.

Q And so Mr. Snider's point, which I would ask if you disagree or agree, is that procuring storage through this competitive procurement framework is more beneficial to customers than procuring it through a traditional PURPA framework which is what NCSEA is advocating; is that correct?

A No. That is not correct.

Q Which -- NC -- which part is not correct?

A So first and foremost, and I say this as a non-

OFFICIAL COPY

Jul 29 2019

attorney, however, HB 589 did not exempt the state from complying with PURPA, and there's still opportunities for -- for QFs to be added to the system and for QFs to -- within the construct of their existing, you know, contracts to -- to improve their facilities. And so -- so the first point is that I believe we are still in compliance with PURPA, and there is still an opportunity for QFs to be added to the system. Whether or not a competitive procurement program for storage is the best way to approach the -- the question of how to add storage to the system, I think, is a -- is a worthy one to explore, perhaps.

I would add that to the extent that the Utility wants to participate in a competitive procurement program for the procurement of the 300 MW or approximately $500,000,000 of batteries, as proposed, that may also be worth exploring. But regardless of whether there may be some benefits associated with competitive procurement, it is NCSEA's view that it is the contractual right of the QFs to add storage to the existing facilities. And we have offered, again, a concession in which to address the concerns about maximizing ratepayer value that those storage systems could go on the updated avoided cost rate, but, again, if the Utility is not favorable to that

OFFICIAL COPY

Jul 29 2019

concession, then we reserve the right to -- to add those QFs under the existing standard offer PPA terms and conditions.

Q I think we're just going to have to disagree about whether its a concession or not, but in terms of the avoided cost rates, the Company is not being obstructionist in prohibiting Cypress Creek or another developer NCSEA member from adding storage; is that corr--- or, yes, in making a material alteration to add storage; is that correct?

A Can you repeat the question?

Q Isn't it correct that the Company's position is not prohibiting the generator, the qualifying facility, from adding storage?

A So first and foremost, I would note that there are two distinct issues, the interconnection of PPA, the interconnection standard thus far, and Duke's position on it has obstructed the ability for QFs to add storage. With respect to the PPA treatment, it is our view that this is, in fact, an obstruction to the addition of storage resources for a variety of reasons.

And the first and foremost of those is that Cypress Creek nor any QF owner that I know of would accept a commercial treatment where it has to terminate

OFFICIAL COPY

Jul 29 2019

its entire PPA and recontract at a wholly separate rate and on a reduced tenor down to five years, which is all that's available to nonstandard offer systems, of which the -- the limitation has now been reduced to 1 MW per 589. And so the practical implication of that sort of treatment is to wholly obstruct the addition of storage to committed generators. So in our view, that, by any reasonable metric, constitutes a substantial obstacle to the addition of storage.

Q And so let's talk about why Cypress Creek wants to make this compromise. What is the benefit to Cypress creek in making this proposal?

MR. SMITH: I'll object to that. It's NCSEA's position to make the compromise.

Q On behalf of NCSEA.

A So, in part, our motivation here is to respond to the concerns expressed by the Utility about the variability and the nondispatchability of these resources. We would like these resources to be more valuable to ratepayers. We would like them to be more amenable to the Utility, to the Commission, and to all stakeholders in the state. And we see an opportunity to utilize this emerging technology to -- to store power when it's needed less and to discharge it when it's

OFFICIAL COPY

Jul 29 2019

needed more, based on the price signals that are available to that generator, including possibly not even just bulk time shifting or peak capacity deferral, but also a smoothing of the production curve in a way that could obviate the need for an integration charge, which I believe it is now Duke's position, at least, that the addition of such storage equipment would obviate the need for such an integration charge.

And so we see a variety of benefits to adding and utilizing these resources. Of course, as independent businesses, the only way in which it is feasible to add and invest in such equipment is if there is at least a revenue requirement met, just as is the case with the Utility. And, in fact, I think in our case, the rate of return would be substantially lower than their guaranteed rate of return for their own capital investments. But we see much value to ratepayers and to the overall state and to utilizing this emerging technology if we can do so.

Q Just for my education, what is the rate of return that you would require to make this investment?

A I'm not in the position to answer that question.

Q Substantially lower. Okay. I'm going to --

CHAIR MITCHELL: Mr. Breitschwerdt, just make

OFFICIAL COPY

Jul 29 2019

sure you talk into your mic.

MR. BREITSCHWERDT: Yes, ma'am.

Q I'm going to move on. So one of the concerns that Duke Energy has in this proceeding is the fact that the addition of storage to an existing QF fails to recognize the significantly higher avoided cost rates that were paid to these old legacy QFs; would you agree with that?

A Well, I disagree with the characterization that they are stale or excessive rates for a variety of reasons that I do discuss in my testimony. I would also note that if we actually go and look at those rates, especially, say, in a non-peak summer period, that they align quite substantially with even the updated on-peak capacity rate proposed by the Utility in this proceeding. And so the practical effect in the summer would actually be to time shift from -- even under the old rate, mind you -- to time shift from an off-peak period to an on-peak period that aligns, again, with the Utility's own updated on-peak period, which I think extends to at least 10:00 p.m. in the new rate structure, subject to check. So I don't necessarily see that there is a negative impact on ratepayers, even if they were added at the old rate structure.

OFFICIAL COPY

Jul 29 2019

Q The old rates, the Sub 136 rates, were significantly higher -- materially higher than the Sub 140 rates; would you agree with that?

A On a blended rate basis that may be correct, but, in fact, on an on-peak basis, it -- subject to check, my understanding is that the Utility has proposed even higher on-peak compensation rates for its new on-peak capacity periods in the wintertime. So it depends on what period we're looking at, and it is inaccurate to necessarily characterize that all periods are higher in the prior rate structures.

Q So if it wasn't -- if it's not accurate to say it was higher in the prior rate structure, why not move to the new rates? If that's Duke Energy's position, that it's beneficial to customers, it's appropriate under the PAPA (sic), you're making material alteration to move to -- to modify the facility to add storage, then you should move to the new avoided cost rates which most accurately reflect Duke's current avoided cost --

A No.

Q -- and you're saying the old rates were not necessarily higher. Why would the industry not be supportive of that?

A Thank you for asking. Because, in fact,

OFFICIAL COPY

Jul 29 2019

NCSEA's position and its concession is exactly that position, and so we are willing to accept a compromise or are willing to offer a concession in which the output of the storage -- the additional storage capacity would be subject to the updated avoided cost rate. And so if the Utility is willing to -- Duke, in particular, is willing to change its position and move towards that compromise, we are willing to accept it, and I would also note that we appreciate that Dominion, in its respo--- in its rebuttal testimony, appears to have moved to accept this compromise position as well. And so we -- we welcome Duke Energy moving towards that position.

Q And just to be clear, a new QF today that's being proposed, assuming the ancillary services charge -- integration services charge is approved, would be required to pay for the ancillaries that they provided to the system, is that correct, or they impose on the system; is that correct?

MR. SMITH: I'm going to object. It's requesting a legal conclusion to the current docket and it's outside of the scope of his testimony, I think.

MR. BREITSCHWERDT: It goes to the value proposition of their compromised proposal to add storage.

MR. SMITH: But his position is based on -- and

OFFICIAL COPY

Jul 29 2019

we're talking about online QFs. I mean, that was my understanding of what -- the Order that came out of the interconnection docket and how it applied here is online QFs, not proposed and -- and what Brett was talking about.

CHAIR MITCHELL: Where are you going with this question, Mr. Breitschwerdt?

MR. BREITSCHWERDT: So the concept being that a QF that adds storage today should be assigned the ancillary services charge unless they operate as a controlled solar generator, and an existing QF that adds storage is already exempted from the ancillary services charge. So until they enter into a new PPA, they're not obligated to make that -- to make those operational changes to provide actual value to customers.

CHAIR MITCHELL: I'm going to allow -- ask the question again for purposes of the record. We recognize that he's not a lawyer. So, again, I'll just make that point clear. And Mr. Norris, please answer the question once asked.

Q So Mr. Norris, I'll repeat the question. In terms of adding storage to an existing QF today, wouldn't you agree that that QF, based on the stipulated proposal for the integration services charge, would be exempted

OFFICIAL COPY

Jul 29 2019

from that charge?

A That would be my understanding on two points, one, because existing QFs are inherently exempted if they have established a LEO prior to, I believe, November 1, 2018. They would also be exempted due to, I believe, Duke's position, which is that any operating facility with a storage device will be exempt from the integration charge.

Q But it is a storage device if they operate in a controlled manner that provides the value to customers that your testimony asserts that QFs will provide -- or QFs that add storage will provide; is that correct?

A Can you repeat the question? I'm...

Q Under the Stipulation you have to operate as a controlled solar generator if you're a new QF that adds storage, and our -- the question is whether or not an exiting QF would similarly have to make operational changes to avoid the ancillary services charge?

A I'll just state this again, is my understanding is that all facilities that have established a LEO prior to November 1st -- under your proposal, November 1st, 2018, would be exempted from the integration charge, and additionally, any QF with a storage device would be exempted, so in this case there is a -- to my

OFFICIAL COPY

Jul 29 2019

understanding, a double protection from the proposed integration charge.

Q Okay. So let me just wrap this up here. So under the Cypress Creek -- strike that. Under the NCSEA proposal, would an existing QF make more revenue than they would if they went to the current avoided cost, as proposed by Duke Energy in this proceeding, when you add storage?

A I actually do not know the question -- the answer to that question, in part because we haven't run all the models based on the proposed rate structure, in part because the rate structure is not finalized. However, I would -- I would sincerely note that it could go either way because of the point that I made earlier that some of the on-peak capacity value that is being provided, the compensation rate, and the updated rate structure is substantially higher than in the past rate structures, that it could, in fact, be the case that revenue would be higher under the updated rate structure. And that is not a -- there's nothing wrong with that. That is -- in fact, that's the price signal that is being established based on a review of the Utility's capacity needs, primarily, in that instance, and the price signal is what -- determines what incentive is available to

OFFICIAL COPY

Jul 29 2019

independent capacity to be constructed. and it helps to obviate the need for the Utility's rate basing of such capacity. So I sincerely do not know the answer and, honestly, it could go either way.

Q Okay.

MR. BREITSCHWERDT: That's all the questions I have.

CROSS EXAMINATION BY MR. DANTONIO:

Q Good afternoon, Mr. Norris. Nick Dantonio representing Dominion Energy. I just have one line of questions for you and a point of clarification, I guess. Do you have your supplemental testimony in front of you there?

A Yeah. I -- let me just pull it up here, if you give me --

Q Sure.

A -- a second.

Q We're going to be sticking mostly around page 10, if you want to --

A Oh, page 10. Okay.

Q Are you there?

A Yeah.

Q Okay. Let's -- we can go for the point of clarification first. The -- it's the simpler one. A

OFFICIAL COPY

Jul 29 2019

couple times in your testimony you reference an avoided cost rate schedule, in the singular, offered by the North Carolina utilities. So one example there is on page 10, line 8. Do you see that?

A That's right.

Q Are you aware that Duke and Dominion are offering separate rate schedules in this proceeding?

A I am aware of that.

Q Okay. And Dominion is actually offering two schedules, the 19-FP and the 19-LMP?

A (Nods affirmatively.)

Q Okay. So there's -- there's more than just one utility rate schedule here, so that's the only clarification. The other thing I'd like to talk about is further down on this page, is your reference to value streams. One of the references there starts on line 17 of that page -- or the paragraph starts on line 17. And you talk about how under this avoided cost rate schedule the QFs can tap into some of these value streams. So there's -- one in particular that I'd like to ask about is the -- the solar clipping there.

A Uh-huh.

Q And you probably see that. And like we've been saying, you're not a lawyer, I'm not an engineer, so

OFFICIAL COPY

Jul 29 2019

correct me if I'm wrong here, but my understanding of solar clipping and what -- what happens there is that when a QF produces energy on its side, DC energy, it has to pass through an inverter and then it goes to the meter and out onto the grid, right?

A Right.

Q But that inverter has a capacity limit, and if the QF is trying to push too much power through the inverter, anything extra over that limit gets clipped off --

A That's right.

Q -- and for lack of a better word disappears unless you have a battery there. Is that generally correct?

A That is generally correct.

Q Okay. Good. So -- but when you add a battery to your facility, then that otherwise clipped energy you would presumably move into the battery, correct?

A That is a -- that is a possible way of utilizing the battery, would be to avoid the wasted energy in that scenario.

Q Would there be any circumstance where you would just let the energy be clipped and not store it in the battery if you had a battery at your facility?

OFFICIAL COPY

Jul 29 2019

A It depends on what capacity, say, is available in the battery at that time. You know, it could be the case that due to the rate structure and the scheduling of the battery, that it may already be fully stored, based on if they had storage of -- of generated power on an off-peak period, say, that morning. So it just depends on the rate structure, that daily schedule for the facility. But -- so, yes, there are instances where you might not store that clip power.

Q Okay. And it sounds --

A But there are instances where you would.

Q Okay. And it sounds like the primary instance when you wouldn't is if your battery is already full; is that -- do I understand that right?

A Subject to check, that's likely an accurate characterization.

Q Okay. So then if you -- under the scenario where you are moving the clipped energy into a battery and you're not letting it just disappear, presumably you're going to wait until the inverter is not at max capacity and then you're going to inject that otherwise clipped energy back into the grid, right?

A Depending on where the rate structure lands and when the Utility is communicating that that power is

OFFICIAL COPY

Jul 29 2019

needed most, yes, it would be discharged at a later time period.

Q But -- right. At some point that clipped energy is not disappearing. It's going back into the grid?

A Right.

Q Okay. So is it fair to say that because without a battery the QF could not monetize that otherwise clipped energy, that when a QF can use a battery to monetize its energy, then it's ultimately just going to increase the QF's revenues?

A That is -- well, certainly, if it could not monetize the clip power otherwise and it discharges it at a time, again, when the rate structure indicates that that power is needed, then that would result in revenue to the generator. I mean, I would note a couple things. One is that there are, again, key instances where that rate structure, based on its seasonal and -- and time allocation, may not even be at a time when clip power is available. So, for example, in the winter in a non-peak period there may not be any clip power because you may be operating substantially below the AC reading anyway. And then so where it's more likely to come into effect would be in the summertime.

OFFICIAL COPY

Jul 29 2019

Q Uh-huh.

A And if there is a way of resolving, say, the contractual question around the estimated annual generation, then there -- yes, then you could see, potentially, an increase in the generation during that summer period. And, you know, it is our view that this is likely in the interest of ratepayers for a couple reasons. One is because, as I think we've discussed a lot in this proceeding, the intermittent nature of the power imposes -- appears to impose some level of integration cost, and by potentially smoothing that production profile we can actually make the generator more valuable to the system. And if clip power provides some of that service, we think that's inherently valuable. And, again, if the price signals are indicating that that power is needed during certain cases, we think that's of value to ratepayers.

Q Right. So without getting into the whole smoothing versus shifting and the whole indifference debate, I think what I heard at the beginning of that answer is, yes, when you clip power or move otherwise clip power into a battery to later inject it into the system, it likely has the effect to increase the revenues from the qualifying facility, right?

OFFICIAL COPY
Jul 29 2019

A Correct.

Q Okay.

MR. DANTONIO: No further questions.

MR. SMITH: No redirect.

CHAIR MITCHELL: Questions by the Commission for Mr. Norris? Go ahead. Commissioner Brown-Bland.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q Mr. Norris, you mentioned the NC State University study a moment ago, and I assume you've reviewed that?

A I've read the study. It is a -- quite a long study, so I can't speak to every citation or every figure, but I can speak in general terms to -- to various aspects.

Q I want to read a statement from page 131, if you'll just accept it. You can turn to it, if you like, or you can just accept it --

A Yeah.

Q -- subject to check. But it says there that "We estimate that the install cost of the battery storage system is 10 percent lower than a standalone system, due to elimination of a dedicated inverter."

A Uh-huh.

Q Do you see that? Do you agree conceptually

OFFICIAL COPY

Jul 29 2019

with that, and what's been your experience?

A Yeah. No. That's exactly right in the case of a DC coupled battery system because you are installing it behind the existing inverter on the -- on the solar facility, and so you're not having to install a new inverter, say, on a separate -- on a separate system, but you're also avoiding a whole range of other costs, various interconnection facilities costs, if there are any network upgrades even required to install that additional generation unit, I mean, all of the approval processes and the costs associated with that.

And then in addition, as we've discussed, an efficient use of interconnection capacity. You're not requiring additional capacity to be involved in the Utility's studies and their system planning. And, again, you're utilizing an existing interconnection to provide whatever value that battery may be able to provide. So, yes, absolutely, we see a lot of efficiency and potential cost savings there, which is one reason why, I mean, we do see unique value, potentially, in solar plus storage as opposed to standalone storage. I would caveat that there are instances where standalone storage, it can provide more value than solar plus storage. So we wouldn't exclude all those possibilities, and if it is,

OFFICIAL COPY

Jul 29 2019

for example, you know, it is an AC coupled system and its primary use case is to provide ancillary services like frequency regulation, you know, it may, in fact, be more cost efficient to add an additional interconnection request, but there are many cases where we'd see it as more cost effective and of greater value to ratepayers to utilize an existing solar generator interconnection.

Q Well, going back to solar plus, do you have -- are you testifying just conceptually right there or do you have actual experience? What does your experience tell you?

A So our -- our experience, in having looked at the possibility of adding batteries to existing solar facilities, is that especially with some of the more recent QFs, say, that have interconnected, you know, in the past couple years, subject to check, that on those, you know, the inverters are of a certain specification, that they would be appropriate to install a battery behind that inverter and would require no or minimal upgrades, necessarily, to -- to that inverter to accommodate that battery system.

So based on our analysis, and we see advantages there -- you know, in other cases we have used AC coupled batteries, actually, on site next to a storage facility.

OFFICIAL COPY

Jul 29 2019

So that is -- also, you should just be aware that, you know, it is possible to do on-site storage next to a renewable generator that is AC coupled. And there are tradeoffs there. We've talked about the energy efficiency loss you get by converting, you know, the DC into the AC and then, say, in that case you'd have to go back to DC to store it in that -- that AC coupled battery, but then there may be other value streams that could be provided by that AC coupled battery that you could not necessarily provide with the DC coupled battery because of the -- the way the inverter is structured.

And so an example of that may, in fact, be frequency regulation services that the AC coupled system may be able to provide more fast response service than a DC coupled system. So there are just tradeoffs and they have different use applications, but to the extent that we're just talking about, you know, a pure cost basis for equipment and interconnection, it's -- it's almost certainly true in most cases that it is, you know, it's more cost effective to add a battery behind the inverter of an existing facility.

Q Well, with regard to the quantification in that, the 10 percent, can you speak to that? Is that 10 percent, you know, valid? Is that a good number, in your

OFFICIAL COPY

Jul 29 2019

experience?

A That sounds approximately right. I mean, I'm just running the numbers and, you know, if we have a -- a 5 MW system and we have, you know, inverters that are rated up to this 5 MW, what would be the cost of those, but subject to check, I think it's approximately accurate, depending on the size of the system.

Q All right.

COMMISSIONER BROWN-BLAND: Thank you.

THE WITNESS: Yeah.

EXAMINATION BY CHAIR MITCHELL:

Q Mr. Norris, a few questions for you just to help us become better informed about current facts and circumstances. Setting aside for the moment the legal issues that have -- that are before us in this proceeding related to contract terms and conditions, were there an avenue in the interconnection process to expeditiously interconnect an energy storage facility to a generator that's already in service, do you -- what is your opinion on how many such expedited interconnection requests that the Duke utilities would receive? In other words, are we now at the point in time when the economics allow for the addition of storage facilities?

A Yeah. Well, so I -- I would note that based on

OFFICIAL COPY

Jul 29 2019

the -- the limited economic modeling that we've done, none of this is a slam dunk right now because, you know, storage costs continue to decline and it would ultimately be more economic to add in future years, but I would be very surprised if we figure out the interconnection side and whether or not they go on the prior rate or the updated rate that we're going to see, you know, a major influx of new requests for storage additions of these facilities.

And that is, in part, because we're only talking about one or two limited value streams available to those systems. We're only talking about energy and capacity, largely. To the extent that those systems could provide ancillary services, which we know they can, those are not -- you know, those are not valued in the current rate structure or any available tariffs and, in fact, while solar generators are being penalized for ancillary services, in fact. But -- but so even under the limited energy and capacity rate available to these, you know, we do think some would be viable, but I think it's highly unlikely that we're going to see some sort of massive influx.

And so just as an example, you know, the Utility, I think, provided a cost estimate if you were to

OFFICIAL COPY

Jul 29 2019

add batteries equivalent to -- to 10 percent of the existing operating Sub 136 and Sub 140 facilities in the state, and they came up with a cost estimate that I believe was quite reasonable of how much additional revenue might result based on, you know, their provision of more on-peak, say, capacity. That might be a reasonable, you know, figure to -- to assume, say, in the near to medium term, might be up to 10 percent of the existing, you know, Sub 136 and Sub 140 fleet.

Q Okay. Recognizing that business cases differ across jurisdictions, how many -- can you give me a rough idea, you don't have to give me a specific number, but how many solar plus storage facilities is your company operating -- owing or operating at this point in time across the country?

A I would need to check with our -- you know, the latest sort of stats on our --

Q Just a general number.

A Yeah.

Q I don't expect you to --

A Yeah. Well, I would just -- I would estimate that we have, you know, under development or, say, executed PPAs on, say, up to 100 MW of batteries.

Q And can you give me a rough number of projects

OFFICIAL COPY

Jul 29 2019

that that -- that those 100 MW would constitute?

A Again, subject to check, but I would say up to five.

Q Okay. Thank you.

CHAIR MITCHELL: Any additional questions from the Commission?

(No response.)

CHAIR MITCHELL: Questions on Commission's questions?

(No response.)

CHAIR MITCHELL: Thank you, Mr. Norris. You may step down.

MR. SMITH: At this time NCSEA would call Dr. Ben Johnson to the stand.

CHAIR MITCHELL: Good afternoon, Dr. Johnson. Let's go ahead and get you sworn in.

DR. BEN JOHNSON: Having been duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MR. SMITH:

Q Good afternoon, Dr. Johnson.

A Good afternoon.

Q Okay. Could you please state your name and business address for the record.

A Ben Johnson, 5600 Pimlico Drive, Tallahassee,

OFFICIAL COPY

Jul 29 2019

Florida, 32309.

Q And on whose behalf are you testifying?

A NCSEA.

Q Did you cause to be prefiled in this docket on June 21st, 2019, direct testimony consisting of 49 pages?

A Yes. And that testimony incorporated by reference my affidavit that had previously been filed.

Q Thank you. Do you have any corrections or changes to be made to that testimony?

A Just one typo that I thought might be worth mentioning because it could be confusing. And reading through it the last 24 hours I noticed on page 31, line 6, a typo. At the end of that line it says Eastern Savings Time. It was intended to say or should have said Eastern Standard Time.

Q Thank you. And subject to that correction, if I were to ask you the same questions today in that testimony, would your answers be the same as given?

A Yes.

Q Thank you.

MR. SMITH: Madam Chair, at this time I move that the corrected direct testimony of Dr. Ben Johnson be copied into the record as if given orally from the stand.

CHAIR MITCHELL: Hearing no objection, the

OFFICIAL COPY

Jul 29 2019

motion is allowed.

(Whereupon, the direct testimony of Dr. Ben Johnson, as corrected, was copied into the record as if given orally from the stand. The confidential testimony was filed under seal.)

OFFICIAL COPY

Jul 29 2019

I. INTRODUCTION

Q PLEASE STATE YOUR NAME, TITLE, AND EMPLOYER.

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida. I am a Consulting Economist and President of Ben Johnson Associates, Inc., an economic consulting firm specializing in public utility regulation.

Q. PLEASE STATE YOUR EDUCATIONAL AND OCCUPATIONAL EXPERIENCE.

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics.

Over the course of my career, I've been involved in many different types of regulatory proceedings in many different jurisdictions. My work has also encompassed an unusually broad range of issues – from setting the appropriate rate of return, to the appropriate items to allow or disallow in the rate base, to weather normalization adjustments, to the allocation of costs across jurisdictions and customer classes, to innovative ideas like price-cap regulation and performance-based regulation.

All told, I have participated in more than 400 regulatory dockets and provided expert testimony on more than 300 occasions before state and federal courts and utility regulatory commissions in 35 states, two Canadian

OFFICIAL COPY

Jul 29 2019

provinces, and the District of Columbia. Most of this work has been performed on behalf of regulatory commissions, consumer advocates, and other government agencies involved in regulation. However, members of my firm and I have worked for other types of clients, including utilities (on rare occasions), firms that compete with utilities, large industrial customers, and non-profit organizations or trade associations.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the North Carolina Sustainable Energy Association ("NCSEA"), an intervenor in this proceeding.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY TO THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. Information about my previous testimony in North Carolina is included in the affidavit attached to the initial comments filed by NCSEA on February 12, 2019 in this proceeding ("my affidavit")[1]. My affidavit and the accompanying report titled "Modeling the Impact of Solar Energy on the System Load and Operations of Duke Energy Carolinas and Duke Energy Progress" ("my report") were prepared by me, and they are true and correct to the best of my knowledge and belief, with one exception: paragraph 98 of my affidavit should start with the words "The DEC and DEP". When I initially wrote this paragraph, I intended to attach a separate report related to price

[1] *NCSEA's Initial Comments*, Attachment 1, Docket No. E-100, Sub 158 (February 12, 2019).

202
OFFICIAL COPY
Jul 29 2019

signals, but this material was subsequently incorporated into the affidavit itself, and I overlooked the need to reword this sentence.

Q. WHAT INFORMATION DID YOU REVIEW IN PREPARING THIS TESTIMONY?

A. I reviewed the Direct Testimony of Glen A. Snider, Steven B. Wheeler, David B. Johnson, and Nick Wintermantel on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress ("DEP") (collectively, "Duke") and the Direct Testimony of Bruce E. Petrie on behalf of Dominion Energy North Carolina ("DENC"). I also reviewed relevant portions of the reply comments filed by Duke and DENC ("the utilities") and the rate design stipulation filed by Duke and the Public Staff on April 18, 2019.

Q. WHAT IS YOUR PURPOSE IN APPEARING BEFORE THE COMMISSION AT THIS TIME?

A. NCSEA asked me to be available to answer questions from the Commission and other parties concerning my affidavit and report (to the extent those questions fall within the scope of this hearing). NCSEA also asked me to expand upon some of the discussion in my affidavit, and to respond to specific portions of the Direct Testimony filed by the utilities, with respect to three issues identified in the Commission's April 24, 2019 Order Scheduling Evidentiary Hearing and Establishing Procedural Schedule: the treatment of expiring QF contracts; the in-service date assumed in developing QF rates;

OFFICIAL COPY
Jul 29 2019

and the stipulation concerning rate design and seasonal allocations filed by Duke and the Public Staff.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. There is nothing in Duke's comments or direct testimony which provides any assurance that existing QFs will continue to be paid for their capacity once their initial contract expires. To the contrary, there are several aspects of the approach Duke is using that could have the effect of largely or entirely eliminating any payment for QF capacity, including the way a "capacity need" is defined, the assumed "in-service" date, and the seasonal allocation factor.

In my testimony, I explain why I disagree with Duke's approach with respect to each of these issues. However, regardless of how these issues are resolved with respect to new QFs, I recommend the Commission include some language in its final order which clarifies that QFs with contracts expiring between now and 2028 are fulfilling an existing capacity need, and they will continue to receive full capacity cost recovery if they sign a renewal contract.

Another issue I deal with in my testimony is the assumed "in-service" date used in the avoided cost and QF rate calculations. The historical data suggests most new projects falling within the current biennial time frame will not be energized until 2021. Very few (if any) new projects were energized on or before January 1, 2019, which is the in-service date assumed by the utilities. This arbitrary, inaccurate assumption leads to various distortions in the

OFFICIAL COPY
Jul 29 2019

calculations, particularly with respect to fuel costs and the use of "zeros" in the capacity cost calculations.

The Commission should require the utilities to publish a schedule of rates (or a formula) that varies over time, so that each QF signing a contract during the 2019-2020 biennial period will receive the appropriate rate based on its actual in-service date. A second-best alternative would be to require the utilities to use a more reasonable assumption. Increasing the accuracy of the in-service date is an appropriate step to take in this proceeding – one that will provide further confirmation that the regulatory process is not biased for or against any particular interest group, and that improvements are not contingent upon the willingness of the utilities to do the work needed for their implementation.

The stipulation filed by Duke and the Public Staff on April 18, 2019 provides an improvement to the energy rate design with respect to seasonal and hourly patterns, but I recommend the Commission consider going even further in this direction by requiring the utilities to calculate separate rates for each hour of each month. These rates can be succinctly displayed in a simple matrix of 12 columns (representing months) and 24 rows (representing each hour of the day). While this might seem more complex, it would actually be easier for QFs to analyze and respond to this 12x24 matrix than the less granular design used in the stipulation.

OFFICIAL COPY
Jul 29 2019

Furthermore, the stipulation does not offer any improvements with respect to avoided capacity costs or with respect to geography and weather fluctuations. Given the importance of QF power to the utilities' operations, I believe the Commission should push the utilities to make further improvements with respect to geographic cost differences and the application of real time pricing during extreme conditions – the relatively small number of hours when system costs are extremely high or extremely low. The Commission can move in this direction in a cautious, deliberate manner by including language in its final order directing the utilities to develop detailed plans for how they would go about implementing geographically granular rates and real time pricing during a small number of hours, for the Commission's consideration in a future proceeding.

Finally, I recommend the Commission reject the seasonal allocation factors used in the stipulation, which would unreasonably reduce (in fact, entirely, or almost entirely, eliminate) capacity payments during the summer. This is inconsistent with the fact that DEC and DEP are both primarily summer peaking utilities, as indicated by the fact that most hours with usage near the annual peak occur during the summer. In fact, usage in excess of 95% of the annual peak occurs 958% more frequently in the summer than in the winter, while usage in excess of 90% of the annual peak occurs 929% more frequently in the summer than in the winter.

OFFICIAL COPY
Jul 29 2019

Common sense and economic theory both suggest that a large share of capacity costs should be allocated to the summer. There is simply not any historical data to support the idea that it is appropriate to allocate all, or nearly all, capacity costs to the winter. The need for a more appropriate seasonal allocation approach is particularly strong in the case of existing solar QFs that invested in North Carolina on the understanding and expectation they would paid for the capacity they provide. It would clearly not be appropriate for Duke to continue to benefit from this capacity without providing fair payment for it. Yet, that would be the result of requiring them to renew their contracts using a seasonal allocation factor which assumes they will continue to provide valuable capacity during the summer, but will not be fairly compensated for that capacity.

II. EXPIRING QF CONTRACTS

Q. HAS DUKE ADEQUATELY RESOLVED YOUR CONCERNS WITH RESPECT TO EXPIRING QF CONTRACTS?

A. No. Duke has clarified some aspects of its approach, but it has not alleviated my concerns with respect to the treatment of existing QFs in North Carolina that have contracts expiring during the next 10 years. For example, the first concern discussed in my affidavit was that these QFs are currently helping to meet the utilities' capacity needs, and there is no principled basis for ceasing to pay them for the capacity costs they are helping to avoid, once their

OFFICIAL COPY

Jul 29 2019

contracts come up for renewal. Duke sidesteps this concern without directly addressing it, or any of the associated public policy implications.

There is nothing in Duke's reply comments or direct testimony which provides any assurance that existing QFs will continue to be paid for their capacity once their initial contract expires. To the contrary, it appears that Duke has positioned itself to argue in future biennial proceedings or contract negotiations that the capacity provided by any individual QF is too small to have any beneficial impact on fulfilling Duke's capacity needs, or the timing of the contract expiration is such that Duke is unable to avoid or delay future planned capacity additions during the initial years of a renewal contract:

> HB 589 and the Commission's 2016 Sub 148 Order, taken together, establish that capacity is only appropriately avoided (and credit assigned under the peaker methodology) starting with the year when the utility's most recent IRP demonstrates a need for capacity that can actually be avoided.[2]

This statement fails to acknowledge the fact that a utility's IRP, in considering whether a need for additional capacity exists, starts by comparing existing capacity to projected demand. Unless demand is projected to decline, or existing capacity significantly exceeds projected demand, existing generation resources, whether owned by the utility or a QF, by definition are needed to meet demand. Moreover, the utility should not be allowed to circumvent this truism by adding surplus capacity and then claiming that QF

---

[2] *Direct Testimony of Glen A. Snider on Behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, p. 12, Docket No. E-100, Sub 158 (May 21, 2019) ("Snider Direct").

208
OFFICIAL COPY
Jul 29 2019

capacity is not needed. Likewise, Duke fails to recognize that contract renewals do not add new capacity (which may or may not be needed) but simply maintain the presence of capacity that already exists, and is already being used to meet customer needs. The bottom line is that where an existing QF is currently providing needed capacity to serve load, it should have the opportunity to continue to do so and to be paid for the capacity it provides.

Q. DOES DUKE'S PROPOSAL HAVE SIMILAR FLAWS WHEN APPLIED TO NEW PROJECTS?

A. Yes. Any QF brought online in the future at that point will become an existing QF, so it will soon face the same problem described above. In fact, it may never be paid for capacity even though Duke is using this capacity to serve load growth and other capacity needs that arise over the operating life of the QF. Regardless of when a QF contract is signed, or when it expires, there is very little chance the timing will align with the narrow window when a "need" for additional capacity is shown in the most recent IRP. To the contrary, there is likely to be a substantial discrepancy between the contract timing and the date when "the utility's most recent IRP demonstrates a need for capacity that can actually be avoided."

A discrepancy is almost inevitable because of the long lead times involved with planning and construction of new generating units. A utility typically commits to the construction of a new conventional generating unit at least three years before the new unit is actually needed, so the first date with

OFFICIAL COPY

Jul 29 2019

a "need" shown in the IRP will typically be at least a few years away. In fact, the first date with a "need" that does not have a corresponding plan for meeting the need may be four or more years into the future. Due to the "lumpiness" of capacity additions, Duke maintains ample additional capacity over and above the minimum required reserve margin during years immediately after new units are added to the fleet – further delaying any "need" for new capacity.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE TO ILLUSTRATE THIS PROBLEM?

A. Yes. Assume a QF has a long-term contract with DEC that expires January 2023. Under Duke's reasoning, it could argue that no capacity payments should be made to the QF during 2023, 2024, 2025, 2026 and 2027 – assuming 2028 is the first year when its IRP demonstrates a "need for capacity that can actually be avoided." If the QF signs a new 5-year contract that goes into effect in 2023, it will effectively be forced to accept the loss of any compensation for its capacity during the entirety of the new contract term.

Furthermore, a similar problem could arise at the expiration of the contract. There is no assurance that a "need for capacity that can actually be avoided" will be shown in the most recent IRP when the initial contract expires in 2028. More likely, at that point Duke's "most recent" IRP will show additional commitments have been made to meet the need that was originally projected for 2028, and therefore the first year with a "need for capacity that can actually be avoided" will then be several years later, when

OFFICIAL COPY

Jul 29 2019

the contract is renewed. The net result could be a "catch-22" which systematically discriminates against QF during the contract renewal process, preventing them from being fully and fairly compensated for the capacity they provide.

Q. CAN YOU ELABORATE ON WHY IT WOULD BE INAPPROPRIATE TO REDUCE OR DENY QF CAPACITY PAYMENTS IN THIS MANNER?

A. Yes. Depending on how the concept of a "need for capacity that can actually be avoided" is applied to existing QFs, there may be no reasonable opportunity for them to achieve full capacity-cost recovery when their contracts are up for renewal. This would be deeply unfair to QFs who have invested in North Carolina on the reasonable expectation they will be fully and fairly compensated for the capacity benefits they provide – just as they were during the initial contract term. It would also be contrary to the public interest, because it would suggest a severe risk of arbitrary and unreasonable policy changes that will undermine investor confidence in the state legislative and regulatory policy-making apparatus.

Duke's approach would also be severely discriminatory, since it would only apply to QFs, and not to Duke – which would continue to receive full capacity-cost recovery for all of the generating units in its rate base, regardless of whether or when the utility's most recent IRP demonstrates a "need for capacity." This systematic discrimination would be inconsistent with PURPA

OFFICIAL COPY

Jul 29 2019

and the associated FERC rules, which assume QFs will be provided with a meaningful opportunity to fully recover "capacity costs" when the QF commits to a long-term fixed price contract.

In general, the goals of PURPA and the interests of society as a whole, including the using and consuming public in North Carolina specifically, are best promoted when PURPA is implemented in a way that encourages QF competition. Under PURPA, QFs are generally entitled to be paid the full amount of avoided costs, including both energy and capacity costs if they commit to a long-term fixed-price contract. However, if a QF is only going to receive energy payments, it is entitled to sell its energy on an "as-available" basis – which provides the QF with maximum flexibility to attempt to sell its capacity to another buyer. Making capacity payments to existing QFs contingent upon a finding that additional new capacity is needed is fundamentally inconsistent with this structure, since it would deny QFs the opportunity to receive full payment for their capacity, even if they are willing to continue to commit their capacity to Duke at the end of their current contract.

As I discussed in my affidavit, DEC has numerous QF purchase contracts that are up for renewal over the next 10 years. If these existing contracts are appropriately analyzed, along with the planned upgrades to existing generating units and other factors discussed in my affidavit, I believe the Commission can, and should, conclude that DEC has a "capacity need"

OFFICIAL COPY

Jul 29 2019

that is being served by these existing QFs. That need can also potentially be served by new QFs, to the extent some of the existing QFs do not renew their contracts. However, to be perfectly clear, regardless of how the Commission resolves this issue with respect to new QFs, I recommend it include language in its order which clarifies that QFs with contracts expiring between now and 2028 are fulfilling an existing capacity need, and they will not be denied a reasonable opportunity to continue to receive full capacity cost recovery regardless of whether or not new QFs will be paid for additional capacity they bring to the system.

I believe it would be a mistake to interpret HB 589 as requiring the Commission to "take" the capacity of small QFs without providing them with fair compensation for the value of what is being taken. This is not just a question of statutory interpretation, substantive due process or basic fairness – it is also a question of maintaining a healthy investment climate in the State. It would not be appropriate to adopt a policy which has the effect of systematically taking capacity from small QFs without giving them any reasonable opportunity to be fairly compensated for the capacity costs that are thereby avoided. This would discourage future QF investment in the state, and it could have broader implications – undermining investor confidence in the state legislative and regulatory policy-making apparatus – especially since that policy would be in direct conflict with the long-standing, well understood core principles of PURPA.

OFFICIAL COPY

Jul 29 2019

PURPA specifically states that QF rates must not "discriminate against qualifying cogenerators or qualifying small power producers."[3] Under rate base regulation, Duke is allowed to recover the cost of its new generating units once they are completed and put into commercial operation, as long as that capacity remains "used and useful" -- even if the most recent IRP does not show a "need" for capacity during some years.

When Duke invests in generating capacity in North Carolina, it is not denied capacity cost recovery simply because a "need" for more capacity has not been demonstrated in the IRP for a particular year, or because subsequent investments are adequately meeting the capacity need that was initially fulfilled by that investment. Under nearly all circumstances, once an investment enters the rate base it remains there regardless of changing circumstances. QFs should be given reasonably comparable treatment.

To be clear, I am not suggesting that QF's should to be given, or need, the same level of cost recovery assurance that Duke enjoys. All that is needed is a legislative and regulatory environment that does not unreasonably discriminate against QFs. Simply stated, the Commission should continue to provide a reasonable opportunity for QFs to be fully compensated for the capacity costs they enable the utilities to avoid. If capacity is continuously provided by the QF, there should not be a gap in the payments they receive for avoided capacity costs each time their contract is renewed.

[3] 16 U.S.C. § 824a-3(a).

OFFICIAL COPY

Jul 29 2019

Q. DO YOU HAVE A RECOMMENDATION FOR HOW THIS CONTINUITY COULD BE ACHIEVED?

A. Yes. To ensure that the utility continuously and fully avoids capacity costs (without any gaps), the QF would need to sign a new contract several years before the old contract expires, or it will need to make a legally binding commitment to provide capacity before it signs the new contract. To facilitate the latter process, the Commission could require QFs to file notice with the utility at least 3 years before the current PPA expires indicating whether the QF is committing to continuously provide capacity and energy (without interruption) after the current contract expires – and specifying the length of that capacity commitment.

To the extent the QF confirms its capacity will be continuously available, the utility would include that capacity in the IRP – treating it as a committed generation resource, and the QF would be entitled to receive full avoided capacity payments without interruption for the full duration of the commitment period (with the actual payment rate and other details to be determined when the new contract is signed).

If a QF does not make a post-contract commitment, it will retain maximum flexibility to choose its course of action when the existing contract expires – including the option to sell power on an energy-only "as available" basis, or to sign a new fixed price contract at the same terms applicable to a new QF (e.g. with little or no capacity payments).

OFFICIAL COPY

Jul 29 2019

If the QF does not make a capacity commitment, or it only commits to a short period of time, the utility would exclude the QF's capacity from the IRP at the end of the contract term or commitment period. The removal of that capacity would be factored into the calculation of the extent to which a "need" for capacity exists each year – similar to the calculations that are developed when an existing generating plant is scheduled for retirement, or a wholesale purchase contract is expiring and is not expected to be renewed.

Q. WOULD THIS RESULT IN A MORE EFFICIENT PLANNING PROCESS AND USE OF GENERATION RESOURCES?

A. Yes. This proposal would ensure that existing QF capacity is included in the IRP process to only to the extent (and to the full extent) that QFs are actually committed to renewing their contract. The portion of capacity from expiring contracts that is not legally committed would still be evaluated in the IRP, but the associated uncertainties would be appropriately considered. For instance, the optimal strategy might be to plan on using short-term market purchases to fill the gap resulting from QF contracts that are not renewed, or to purchase capacity from new QFs instead. Constructing a new generating unit might be the logical option at a later time – once it is clear that certain QF capacity will no longer be available. The end result of this approach is to treat both new and existing QFs fairly, and to avoid the costly, inefficient duplication of generation resources.

OFFICIAL COPY
Jul 29 2019

III. ASSUMED IN-SERVICE DATE

Q. HAVE THE UTILITIES PROVIDED A VALID JUSTIFICATION FOR USING A JANUARY 1, 2019 IN-SERVICE DATE TO ESTABLISH QF RATES?

A. No. In my affidavit, I criticized the utilities for using January 1, 2019 as the starting point for their avoided cost and QF rate calculations. I explained that since the proposed standard offer tariff provides a single set of rates that will apply to all eligible QFs regardless of when they begin delivering power, a less arbitrary, more reasonable in-service assumption should be used. In their direct testimony, the utilities made very little effort to defend their assumed in-service date of January 1, 2019, nor did they offer any response to my concern that this assumption distorts all of the avoided cost calculations. Rather than just admitting the January 1, 2019 assumption is inaccurate, or offering to change this assumption, they concentrated on criticizing the alternative date of December 31, 2021 which I suggested in my affidavit.

Q. WHY IS NCSEA RAISING THIS ISSUE FOR THE FIRST TIME IN THIS PROCEEDING?

A. As other aspects of the QF rate development process have evolved, the impact of an inaccurate in-service date has become more evident and more serious. An inaccurate in-service date leads to inaccuracies throughout the rate-setting process. For instance, an unrealistically early in-service date results in QFs being compensated for avoided energy costs based on lower gas prices

217

OFFICIAL COPY

Jul 29 2019

associated with an earlier set of years than the actual years when the QF will produce power – a time when the utility will actually avoid higher energy costs due to higher fuel prices. However, the problem has become particularly severe with respect to capacity costs, because the Commission is now including "zeros" in the capacity cost calculation. If capacity cost recovery is excluded during the initial years of a long-term contract, accurately determining the correct number of zeros to include in the calculations is vitally important; this requires an accurate assumption concerning the in-service date of the QF.

For example, consider a QF that provides capacity and energy to DENC starting in December 2021. Under the utilities' approach, if the QF signs a 5-year contract, it will be paid a levelized capacity rate based on DENC's avoided capacity costs during two years: 2022 and 2023; zero capacity costs will be assumed for the remaining three years. The problem is that DENC assumes the QF will provide power during 2019, 2020 and 2021, which are years when capacity costs are deemed to be unavoidable, when in reality power will be delivered during a later time frame. If the QF is actually energized in December 2021, it will enable DENC to avoid capacity costs throughout the entire 5-year contract term of 2022-2026.

The problem would be diluted, but not eliminated, if the QF signs a 10-year contract. In that case, the QF will provide power during the years 2022-2031, but the rate calculations will assume it provides power during

OFFICIAL COPY

Jul 29 2019

2019-2028. As a result of this timing discrepancy, the QF will only be paid for avoided capacity costs during 7 years of the 10-year term. In reality, DENC will avoid capacity costs during all 10 years of a 2022-2031 contract duration, but this is not recognized when the rates are calculated. Similar problems apply to DEC and DEP, with the specific impact depending on the number of zeros included in their capacity rate calculations.

This problem was not as evident in previous biennial proceedings, since the Commission had rejected proposals to include zeros in the capacity rate calculations. In past proceedings, the Net Present Value calculations included capacity costs for all 5 years of a 5-year contract (or all 10 years of a 10-year contract) regardless of what in-service date was assumed. Accurately determining the correct number of zeros was not an issue, since there were no zeros in the calculations.

Strictly speaking, a more accurate in-service date will improve the accuracy of all aspects of the rate calculations. For instance, there could be differences in the overall inflation rate compared to the inflation rate applicable to the cost of a new CT, or differences between the percentage factors that are used in calculating the return on investment compared to the discount factors that are used in developing the Net Present Value and levelized annual rate calculations. However, those impacts are relatively minor, and not as clearly demanding a need for improved accuracy as when zeros are being used in the calculations.

OFFICIAL COPY

Jul 29 2019

Q. CAN YOU EXPLAIN WHY YOU THINK FEW QFS WILL ESTABLISH LEOS BEFORE NEW RATES ARE FINALIZED?

A. Yes. Mr. Petrie wondered what support I had for this assertion:

> Dr. Johnson offers no support for his assertion that few QFs are likely to seek to establish LEOs under the new rates until after the rates have been finalized…[4]

I based this statement on my general understanding of the industry, my review of the proposed tariffs, and my review of historical LEO data provided by the utilities in response to discovery, which shows **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

My reasoning is straightforward: QFs are reluctant to commit to a Legally Enforceable Obligation unless and until they have a reasonable degree of assurance that their proposed project will be economically viable. The proposed standard offer tariffs have low QF rates that are fixed for a relatively short period of time, and the tariffs include proposals (especially with respect to solar integration costs) that would increase the risks and uncertainties facing new QF projects. Accordingly, at the time I prepared my affidavit I anticipated that relatively few QFs will commit to a LEO before they know more about the Commission's response to these proposals. This will place

[4] *Direct Testimony of Bruce E, Petrie on Behalf of Dominion Energy North Carolina*, p. 19, Docket No. E-100, Sub 158 (May 21, 2019) ("Petrie Direct").

OFFICIAL COPY
Jul 29 2019

them in a better position to evaluate whether or not a project will be economically viable.

More than 6 months having now elapsed since the proposed rates were filed; if a large number of QFs are willing to commit to a LEO without seeing significant improvement in the proposed tariffs, that trend will already be apparent. Accordingly, the utilities can clarify the record by bringing forward data to show how many QFs have established LEOs in recent months. This data could also be useful to the Commission in determining whether there are any projects that have already been energized that will be paid the standard offer rates established in this proceeding. All of this information will be useful in helping the Commission to judge the reasonableness of my original statement, as well as the reasonableness of the proposed assumed in-service date of January 1, 2019.

Q. YOU MENTIONED HISTORICAL LEO DATA. CAN YOU PROVIDE SOME INSIGHT INTO THIS DATA?

A. Yes. The utilities provided detailed historical data from both North and South Carolina which confirms that an in-service date of January 1, 2019 is not realistic, since this is just 60 days after the tariffs were filed.

The largest, most detailed data set was obtained from DEP, so I will focus on that. **[BEGIN CONFIDENTIAL]** [redacted]

OFFICIAL COPY

Jul 29 2019

[redacted] [END CONFIDENTIAL]

However, these statistics understate the lengthy time lines involved with QF project development, or the degree to which the proposed in-service date is unrealistic, because very few projects obtain their LEO immediately after a biennial rate filing. In most cases there is a substantial additional gap between the date when the standard offer tariff is filed and the LEO date. Consider, for example, the current biennial proceeding. If roughly half the projects that will sign a contract during the 2019-2020 biennial period commit to a LEO during 2019 or sooner, and the other half commit to a LEO during 2020, the median LEO date will be sometime around January 1, 2020. Accordingly, taking all of the various delays into consideration, the historical data suggests the majority of the projects falling within the current biennial time frame will probably not be energized until 2021; very few (if any) will be energized on or before January 1, 2019.

Q. THE UTILITIES CRITICIZED YOUR SUGGESTED ALTERNATIVE ASSUMPTION OF DECEMBER 2021. WHAT IS YOUR RESPONSE?

OFFICIAL COPY

Jul 29 2019

A. By its very nature, a single assumed in-service date will not precisely align with the actual in-service date of every QF. Hence, I was never intending to suggest that it would be infeasible for a QF to energy a project before December 2021. The key point I was making in my affidavit is that a more accurate and reasonable in-service assumption is needed. It was not my intent, and is not my recommendation, to substitute one inaccurate assumption for another. I continue to believe it is completely unrealistic to assume an in-service date of January 1, 2019 for QFs that sign a contract during the 2019-2020 biennial period. With a more appropriate, realistic assumption, roughly half the QFs should end up having an actual in-service date before the assumed date, and roughly half should have an in-service date after the assumed date. I see no conceivable possibility that half of the QFs signing contracts during this biennial period will have an in-service date on or before January 1, 2019.

While I still believe December 2021 is a reasonable alternative, I agree that small QFs proceeding under the Fast Track and Supplemental Review process can proceed more expeditiously than larger projects. Accordingly, it might make sense to use an earlier in-service assumption for these smaller projects than for larger projects. I would point out, however, that a specific assumed date is not the only option. Another solution would be for the Commission to require the utilities to publish a schedule of rates (or a formula) that specifies the applicable rate for all projects signing a contract during the

OFFICIAL COPY

Jul 29 2019

2019-2020 biennial period. Each QF would receive the applicable rate based on its actual in-service date.

This schedule of rates (or formula) could vary at intervals as frequently as monthly, or as infrequently as once a year. If the rate varied annually, projects energized during 2019 would receive payment based on an assumed in-service date of July 1, 2019, projects energized during 2020 would be paid based on an in-service date of July 1, 2020, projects energized during 2021 would be paid based on an in-service date of July 1, 2021, and projects energized during 2022 would be paid based on an in-service date of July 1, 2022.

Q. HOW DID THE UTILITIES RESPOND TO YOUR SUGGESTION THAT RATES COULD VARY DEPENDING ON THE ACTUAL IN-SERVICE DATE?

A. Duke's witness ignored this option, while Mr. Petrie (testifying on behalf of DENC) apparently found it confusing:

> Dr. Johnson's proposal that the Utilities should calculate capacity costs for negotiated PPAs individually based on projected in service date, and present a range of rates based on different in-service dates, should be rejected for similar reasons.
> ...this approach would be inconsistent with prior precedent and would unreasonably burden the Utilities by requiring them to provide multiple pricing choices to developers from which the developer can choose the most beneficial.
> ...This would also make the negotiated PPA process more inefficient, as it would likely lead to disagreements about in-service dates. For example, what happens if the QF's anticipated in-service date that was agreed upon or anticipated when the PPA is negotiated shifts due to

224

OFFICIAL COPY

Jul 29 2019

> interconnection study process? Would the utility be required to recalculate the rates? The proposal presents too many uncertainties to be appropriate. [5]

These criticisms are misplaced, because NCSEA was not, and is not, proposing to tie rates to an anticipated or projected in-service date. Rather, the rate would be based on the actual in-service date. This reduces or eliminates the risk of under-payment if the project begins commercial operation after the assumed or anticipated in-service date; similarly, it reduces or eliminates any risk of over-payment if the QF begins commercial operation before the anticipated or assumed in-service date.

If rates are tied to the actual in-service date, rather than an assumption or projection, there would also be no reason to anticipate difficulties in negotiations or disagreements about the in-service date. The schedule of rates, or rate formula, would be set forth in the tariff or attached to the negotiated contract, based on a straightforward application of the same methodology that is currently being used to estimate avoided energy and capacity costs. The only difference would be the time frame used to develop the avoided cost estimates – it would match the time frame when power will actually be delivered.

There would also be no requirement for the utility to recalculate rates if delays are encountered during the interconnection or construction process. The schedule of rates or formula can be set forth in the tariff, or attached as

---

[5] *Id.* at pp. 17-18.

OFFICIAL COPY

Jul 29 2019

an exhibit to a negotiated contract, so both parties will always know the impact of any actual or potential schedule changes on the rates that will be paid to the QF. There would be no room for confusion or disagreement about what rate is going to apply in any given situation – the rates are established in the tariff or contract, contingent on the actual date when the project goes online and begins delivering energy to the grid. Nor is there any reason for confusion about this date – it could be determined in the same way the utility determines whether the QF is delivering power in sufficient volume to entitle it to compensation pursuant to the contract.

Q. WOULD IT BE DIFFICULT OR BURDENSOME FOR THE UTILITIES TO CALCULATE A SCHEDULE OF RATES TIED TO THE ACTUAL IN-SERVICE DATE?

A. No. It would not be difficult for the utilities to run their rate calculations using different assumed in-service dates. The utilities could modify their workpapers to treat the in-service date as a variable which can be adjusted in the same way "what if" scenarios are routinely handled in computer modeling. An even simpler alternative would be for the utilities to make some copies of their workpapers, and then manually revise the relevant portions of each copy as necessary to be consistent with an alternative in-service date.

Q. YOU MENTIONED THE POSSIBILITY OF ESTABLISHING A SCHEDULE OF RATES THAT VARIES TWICE-ANNUALLY, OR EVEN MONTHLY. IS THIS FEASIBLE?

OFFICIAL COPY

Jul 29 2019

A. Yes. If the utilities decide to modify their workpapers to treat the in-service date as a variable, they could do this in a way that makes it easy to produce a different answer for each month. If they decide instead to make copies of their workpapers, and manually revise them to use an alternative in-service date, it wouldn't be necessary to do this for every month. In fact, a simplified approach might suffice – creating one set of workpapers for the earliest relevant date (e.g. January 1, 2019) and another set for the last potentially relevant date (e.g. January 1, 2023). Rates can easily be calculated for any month in between these "bookends" using mathematical interpolation.

Q. THE UTILITIES CONTEND THAT RATES DO NOT HAVE TO PRECISELY RECOGNIZE THE UTLITY'S ACTUAL AVOIDED COSTS. HOW DO YOU RESPOND?

A. I agree that perfection is not required, and some degree of simplification is reasonable and sometimes necessary. However, the desire for simplicity (or the extra work required to solve a problem) should not become an excuse for allowing the calculations to become biased against QFs. If a single assumed in-service date is going to be used, it should be a realistic one which does not bias the rates downward. If the parties can't agree on an appropriate in-service date, it would make sense to adopt a schedule of rates that allows each QF to be paid based on its actual in-service date. The additional effort required to implement such a schedule of rates would be minor compared to the

OFFICIAL COPY
Jul 29 2019

importance of this issue, and the potential impact on future QF development in the state.

During the past several biennial proceedings, the utilities have pushed for multiple changes to the process they use in calculating avoided costs and setting QF rates. Some changes were controversial; others were not. Some of these changes had the effect of improving the accuracy and precision of the rate calculations; others did not. One thing nearly all of the utilities' proposed changes have had in common is the direction of the change: they nearly always have had the effect of pushing QF rates downward.

Given the importance of QF rates for all of the parties involved in these biennial proceedings, it makes sense for the Commission to improve the accuracy and precision of the rate-setting process where this is feasible. This helps protect the interests of the using and consuming public because it moves closer to the ideal situation under PURPA, where QF rates are precisely equal to avoided costs – no higher and no lower. While it may be impossible to fully achieve this ideal result, it makes sense for the Commission to move in this direction.

The trend towards improving the calculations should not be a one-way street. Proposed improvements that have the effect of decreasing QF rates should not be given preference over improvements running in the other direction. Increasing the accuracy of the in-service date is an appropriate step to take – one that will provide further confirmation that the regulatory process

OFFICIAL COPY

Jul 29 2019

is not biased for or against any particular interest group, and that improvements are not contingent upon the willingness of the utilities to do the work needed for their implementation.

IV. GRANULAR RATE DESIGN

Q. WHAT IS YOUR INITIAL REACTION TO THE RATE DESIGN STIPULATED BY DUKE AND THE PUBLIC STAFF?

A. The energy rate design in the stipulation filed by Duke and the Public Staff on April 18, 2019 is similar to the alternative described in my affidavit at paragraphs 200-206. For the same reasons explained in my affidavit, I believe this stipulated energy rate design is a step in the right direction. However, it does not go as far as it could.

In my affidavit, I identified three major areas where increased granularity and accuracy would be beneficial and feasible: (a) geographic diversity, (b) stable and predictable cost variations based on seasonal and hourly patterns, and (c) less stable and less predictable cost variations due to weather fluctuations. I recommended improving the QF rate design in all three of these areas, in order to improve economic efficiency, to encourage entrepreneurial experimentation and innovation, and to encourage better investment decisions.

The stipulated energy rate design is a significant improvement compared to both the status quo and the rate design initially proposed by the utilities in this proceeding in one of these three areas: variations in avoided

OFFICIAL COPY
Jul 29 2019

energy costs based on seasonal and hourly patterns. The stipulation does not offer any improvements with respect to avoided capacity costs or with respect to geography and weather fluctuations.

Q. ARE FURTHER IMPROVEMENTS FEASIBLE WITH RESPECT TO HOURLY AND SEASONAL COST PATTERNS?

A. Yes. Price signals could be further improved by calculating separate rates for each hour of each month. This approach would provide 288 separate price signals that can be succinctly displayed in a simple matrix of 12 columns (representing months) and 24 rows (representing each hour of the day). While this might seem more complex, it would actually be easier for QFs to analyze and respond to this 12x24 matrix than the less granular design used in the stipulation.

Improved granularity does not require more complexity because the 12x24 approach eliminates the complications associated with weekends and holidays, as well as the complexities associated with daylight savings time. I am not denying that load variations and cost differences can exist arise with respect to week days, weekends, holidays and daylight savings time. However, these nuances are not of great importance in this context and capturing them is not a high priority in the context of QF rates.

QFs have very little opportunity to respond to differences in the price they receive during a week day compared to a weekend or on a holiday. The rain falls and the sun shines the same on a Thursday or Friday as the following

230
OFFICIAL COPY
Jul 29 2019

Saturday; the fact that one is a week day and the other is a weekend doesn't have any significance for the design, engineering and operation of a typical hydro or solar facility. Similarly, there little to be gained by adding complexity to a QF tariff in order to keep track of timing differences related to daylight savings time. Solar output and ambient temperatures are the same whether it is 3 pm Eastern Daylight Time ("EDT") or 2 pm Eastern Savings Time ("EST").

This is not to say that these complexities are equally unimportant in the context of retail tariffs which may have originally formed the basis for the approach used in the utilities' QF tariffs. In the case of commercial and industrial customers, tariff distinctions related to week days, weekends, holidays and daylight savings time can influence decisions relating to their hours of operation, how many employees are assigned to work during different time periods, and other decisions that influence energy usage patterns. Distinctions that are given priority a retail rate context are not necessarily as important in the QF rate context.

It makes more sense to give priority to sending granular price signals that allow more precise alignment with monthly variations in hydro flows and the movement of the sun, as well monthly variations in the timing of when cloud coverage and rainstorms tend to occur. A 12x24 rate design provides more precise price signals, which makes it possible to more precisely match QF revenues to avoided costs, and which can improve economic efficiency by

OFFICIAL COPY
Jul 29 2019

helping QFs make better decisions with respect to the design, engineering and operation of their facilities. This increased granularity will become increasingly significant as storage technologies become more widespread, allowing QFs (including ones that will be renewing their contracts in the future) to fine-tune their responses to the QF rates.

Accordingly, while I applaud Duke and the Public Staff for taking a significant step in the right direction, I recommend the Commission seriously consider going even further in the direction of greater granularity. The 12x24 rate design facilitates more precise price signals without any greater complexity.

Q. ARE FURTHER IMPROVEMENTS FEASIBLE WITH REGARDS TO WEATHER FLUCTUATIONS?

A. Yes. Stronger, more precise price signals could be achieved by implementing Real Time Pricing during extreme conditions – the relatively small number of hours when system costs are extremely high or extremely low. Fixed prices would continue to be applied during the vast majority of the hours each year, thereby providing QFs and their investors with adequate revenue stability and predictability.

Q. DID THE UTILITIES DISCUSS THIS NCSEA PROPOSAL IN THEIR DIRECT TESTIMONY?

A. No. My impression is that the utilities do not dispute the fact that more accurate avoided cost recovery can be achieved by using real time pricing

232

OFFICIAL COPY

Jul 29 2019

during a small number of hours when costs happen to be unusually high or low. The approach described in my affidavit at paragraphs 207 – 217 would support increased pricing accuracy without damaging the ability of QFs to obtain financing, because the vast majority of their revenues would continue to be received through fixed prices that are specified in the power purchased contract, and because reasonable limitations would be placed on the utilities' discretion in applying real time pricing.

Neither Duke or DENC disputed the merits of real time pricing, but they seem to have some qualms about practical implementation issues. Duke did not discuss this NCSEA proposal in its testimony, but it expressed these concerns in its reply comments:

> ...although the Companies agree that time-of-day pricing periods and real-time pricing tariffs for QFs could better align the Companies' actual avoided costs to QF payments, the Companies believe that the more granular pricing periods they have proposed in this proceeding are sufficient at this time. However, as technological advancements are made and more granular pricing becomes less costly and burdensome to administer, the Companies agree to investigate development of time-of-day and real-time pricing periods for standard offer QFs.[6]

It is unclear what "technological advancements" Duke is hoping will become available, or why it believes the concept could be burdensome. DENC more clearly stated its concerns:

> ...incorporating real time pricing [in]to the rate design would unreasonably increase the time and costs of

---

[6] *Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Docket No. E-100, Sub 158 (March 27, 2019) ("Duke Reply Comments"), pp. 74-75.

233

OFFICIAL COPY

Jul 29 2019

> administering standard offer PPAs due to the need for additional personnel and processes to monitor the likelihood and duration of these extreme events.[7]

Q. WHAT IS YOUR RESPONSE TO THESE CONCERNS?

A. I agree these sorts of practical concerns need to be considered, but at most they suggest a need to move cautiously and carefully; they do not provide a valid reason to summarily reject the NCSEA proposal.

All (or nearly all) existing QFs already have their output metered on an hourly or sub-hourly basis, so there is no problem with obtaining the data needed to apply real time pricing during hours when extremely high or low-cost conditions exist. Similarly, practical technological solutions already exist for communicating with QFs to let them know in real-time that extreme cost conditions are anticipated and very high or low pricing may be applied, which will enable the QF to effectively prepare for and respond to the extraordinary cost conditions. These existing technologies include text messages and emails, as well as posting information on the Internet. These communications methods do not require a large amount of effort and the would not be difficult or unreasonably costly to implement.

Similarly, the utilities already have personnel on staff who are monitoring the likelihood and duration of unusual weather conditions (which is what triggers extraordinarily high or low-cost conditions). This is

[7] *Reply Comments of Dominion Energy North* Carolina, Docket No. E-100, Sub 158, (March 27, 2019) ("Dominion Reply Comments"), p. 25.

OFFICIAL COPY

Jul 29 2019

information the utilities need to continuously monitor and evaluate, in order to cost-effectively plan and dispatch their systems, so there would be no need to add additional personnel in order to anticipate and identify times when extremely high or low-cost conditions may occur. Nor would it require a substantial amount of time and effort for existing employees (who are already collecting and analyzing this information as part of their day-to-day responsibilities) to pass this information along, so that times when real time pricing would be appropriate can be identified. The key step – one that would not be unduly burdensome – is to pass this information through to QFs, so they can respond to more accurate price signals during times when costs are extremely high or low.

Q. DENC'S LMP TARIFF IS ENTIRELY BASED ON GEOGRAPHICALLY SPECIFIC REAL TIME PRICING. IS THIS AN APPROPRIATE WAY TO PROVIDE MORE ACCURATE TIME OF DAY AND GEOGRAPHIC PRICE SIGNALS?

A. No. The LMP tariff is not as good a solution as the NCSEA proposal described in my affidavit, because the LMP tariff tightly links the QF's revenues to volatile natural gas and other energy markets. Since most QFs have low variable costs and high fixed costs, this volatility is fundamentally incompatible with the underlying cost structure of most QFs (the most important exception being gas-fired cogenerators). Hence, the LMP rate design is inappropriate for most QFs since it forces the QF to endure

OFFICIAL COPY
Jul 29 2019

significant, unnecessary risks, and it makes it very difficult to project future revenue streams or to obtain debt financing.

Q. CAN THE COMMISSION CAUTIOUSLY MOVE TOWARD MORE ACCURATE, GRANULAR QF PRICES IN THIS PROCEEDING?

A. Yes. It is feasible to move toward more accurate price signals in all three areas: (a) geographic diversity, (b) stable and predictable cost variations based on seasonal and hourly patterns, and (c) less stable and less predictable cost variations due to weather fluctuations. The stipulated rate design makes progress with respect to seasonal and hourly patterns, but greater accuracy is worth pursuing by adopting the 12x24 pricing matrix. Similarly, given the importance of QF power to the utilities' operations, I believe the Commission should push the utilities to make further improvements with respect to geographic cost differences and the application of real time pricing during a small number of extraordinarily high or low-cost hours.

More accurate prices will protect the interests of the using and consuming public by moving closer to the ideal situation where QF rates are precisely equal to avoided costs – no higher and no lower. The Commission can move forward in a cautious, deliberate manner by including language in its final order directing the utilities to develop detailed plans for how they would go about implementing geographically granular rates and real time pricing during a small number of hours, for the Commission's consideration in a future proceeding. This detailed planning process would include

OFFICIAL COPY

Jul 29 2019

identifying and analyzing any relevant administrative or practical problems, and developing proposed strategies for overcoming or minimizing these problems.

The Commission should require the utilities to submit their proposed plans at least 6 months before their tariff filings in the next biennial proceeding, to provide ample opportunity for the Public Staff and other interested parties to review the plans, and to work with the utilities in developing potential improvements, refinements, or alternatives for the Commission's consideration during the next biennial proceeding.

IV. SEASONAL CAPACITY COST ALLOCATIONS

Q. WHAT IS YOUR REACTION TO THE CAPACITY RATE DESIGN AND SEASONAL ALLOCATION INCLUDED IN THE STIPULATION SIGNED BY DUKE AND THE PUBLIC STAFF?

A. The stipulation retains all of the flaws in this aspect of Duke's initial filing in this proceeding. The stipulation allocates 100% of DEP's capacity costs and 90% of DEC's capacity costs to the months of December through March. The remaining 10% of DEC's capacity costs are allocated to the months of July and August. The net result is to unreasonably reduce (and in fact, to entirely, or almost entirely, eliminate) capacity payments to QFs during the summer. The stipulated seasonal cost allocations are inconsistent with the underlying reality that DEC and DEP serve loads that primarily peak during the summer, just like the loads experienced by the PJM system to the north, the Tennessee

OFFICIAL COPY

Jul 29 2019

Valley Authority ("TVA") to the west, Georgia Power to the south and South Carolina Electric & Gas to the east.

Viewing the DEC and DEP systems as predominantly winter peaking is inconsistent with the way these neighboring utilities are viewed, as well as the underlying reality that: (a) long, hot summers occur every year in this part of the country; (b) mild winter days are a frequent occurrence, and uncommonly cold weather rarely lasts for more than a few hours over the course of a few days; (c) virtually all businesses and residences rely on electricity for air conditioning, but many of these customers do not rely on electricity for heating, because natural gas heating offers a viable alternative during the winter.

It is also worth noting that DEC and DEP are continuing to function like summer peaking utilities with respect to some other issues, including the way they have designed and implemented their retail rates, and the way they have designed and implemented their Demand Side Management ("DSM") programs. In fact, one would be hard pressed to find any significant aspect of their operations which has significantly changed in ways that would suggest DEC and DEP truly believe their winter peaks are now more important than their summer peaks.

Q. DID DUKE PROVIDE ANY NEW EVIDENCE TO SUPPORT THE SEASONAL ALLOCATION IN THE STIPULATION?

OFFICIAL COPY

Jul 29 2019

A. No. Essentially the only support for this aspect of the stipulation in Duke's direct testimony was a perfunctory reference to the loss of load risk that Duke's consultants, Astrapé, developed in its Solar Capacity Value Study.

> …it is reasonable and appropriate to adopt the Companies' seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the Astrapé Solar Capacity Value Study. The loss of load risk identifies the times when the Companies forecast generation constraints making QF generation of the greatest value to customers.[8]

Duke did not offer any other evidence in its direct testimony to support the capacity rate design and cost allocation in the stipulation. Tellingly, Duke's direct testimony largely ignored the flaws in its solar modeling, and that of its consultants, which were extensively discussed in my affidavit (e.g. paragraphs 35 – 50) and in my report (e.g. pages 14 – 17 and 25 – 29). The failure to respond to these criticisms is significant in this context, because the Solar Capacity Value Study is heavily dependent upon the assumptions and methodology used in modeling solar output.

The modeling flaws and other problems discussed during the comments phase of this proceeding help explain how it was possible for Duke's consultants to reach the conclusion that nearly all of the loss of load risks are concentrated in the winter months, despite the fact that DEC, DEP and other nearby utilities have long been viewed as summer peaking.

---

[8] Snider Direct, p. 26.

OFFICIAL COPY
Jul 29 2019

Q. IS THERE EVIDENCE IN THIS PROCEEDING WHICH CONTRADICTS THE CAPACITY COST TREATMENT IN THE STIPULATION?

A. Yes. Consider, for example, data related to Duke's decision to focus on July and August, to the exclusion of other summer months. In paragraph 104 of my affidavit, I pointed out that the highest peak in June or September is often close to the highest peak in July or August. In fact, during 2015 the DEC peak in June (20,003) slightly exceeded the peaks in July and August, and the peak in September (18,681) was not far behind. DEP experienced a somewhat similar pattern of monthly peaks that year, with the June peak (12,849) exceeding the July and August peaks. Another example occurred in 2014, when the DEP September peak exceeded the July and August peaks. Similarly, the June peak exceeded the July and August peaks in 2008. The DEC peak in June 2008 also exceeded the July and August peaks that year. Duke did not dispute any of this data, or offer any justification for narrowing the focus to just two summer months in the stipulation – except for the loss of load risk estimates which Astrapé developed using a flawed modeling approach.

Since peak load patterns are normally used to determine the allocation of capacity costs and the design of capacity-related rates, this data strongly suggests that at least some of the capacity costs should be allocated to June and September, along with the months of July and August. Although this data

24C

OFFICIAL COPY

Jul 29 2019

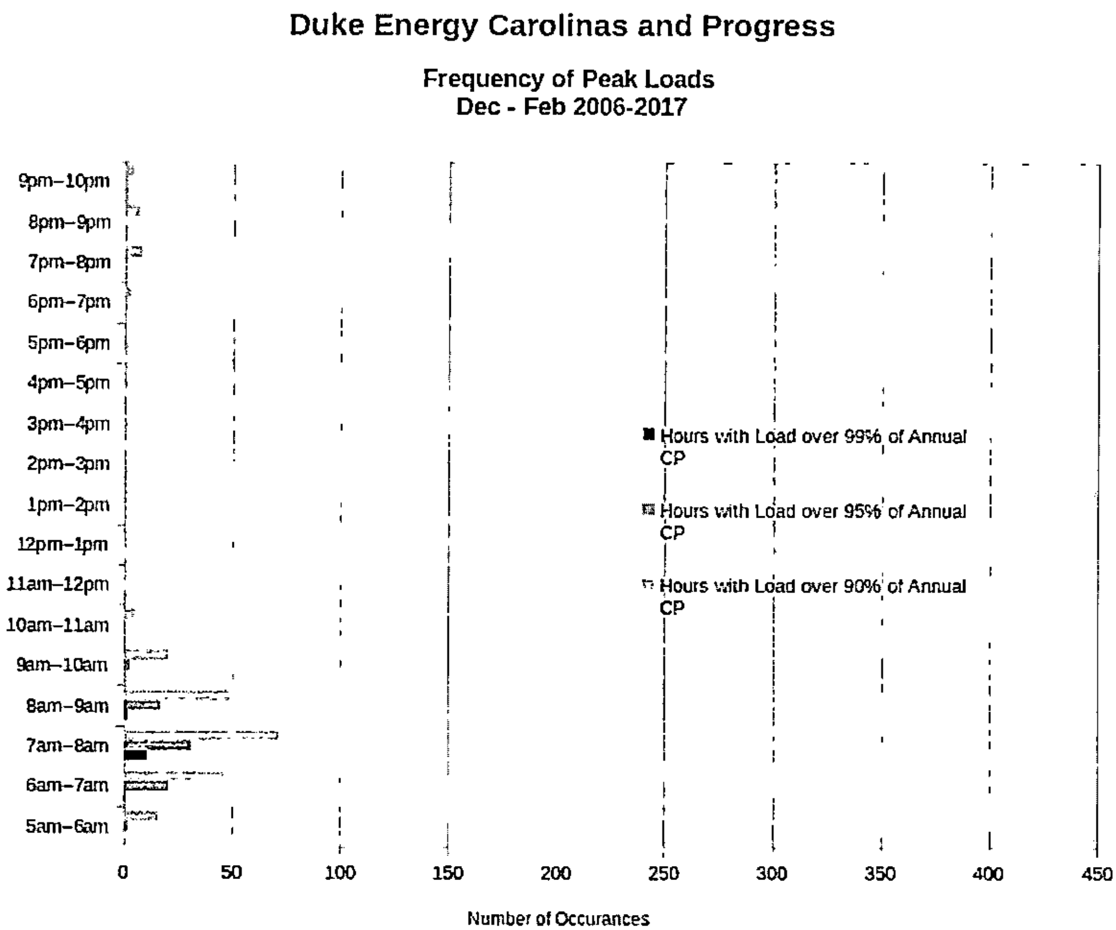
discussed earlier in the proceeding it was simply ignored in developing the stipulation and Duke's direct testimony.

Another example is the hourly load data reported to the FERC on Form 714, which was discussed in my report. This data shows there are very few hours when high levels of peak usage occur during winter months, compared to the much larger number of hours when high levels of peak usage occur during summer months.

The following graph, which was included in my report, shows there were just 14 hours during the months of December through February during the years 2006-2017 when peak usage exceeded 99% of the annual coincident peak. Similarly, it shows there were 74 hours during those months when peak usage exceeded 95% of the annual peak and 241 hours when peak usage exceeded 90% of the annual peak.

OFFICIAL COPY

Jul 29 2019

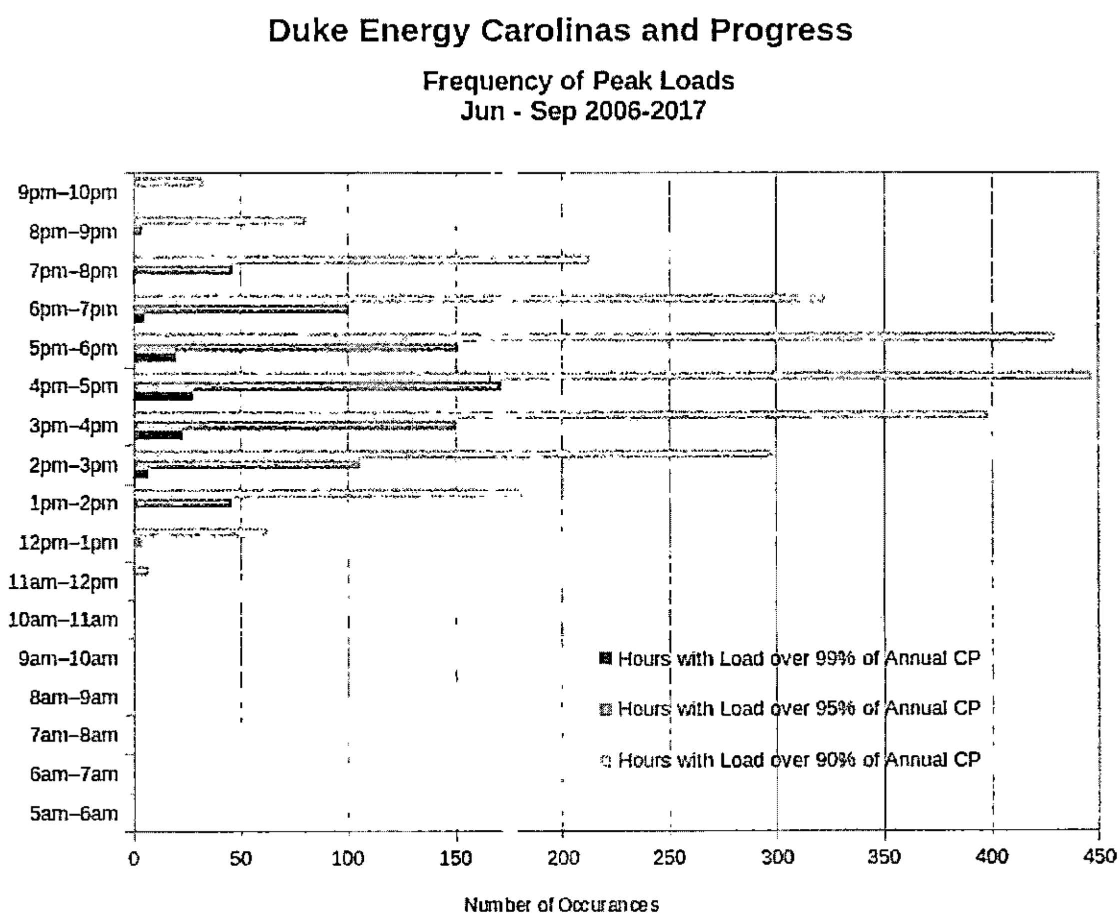


High system peaks occur far more frequently in the summer. For example, according to the hourly load data reported to the FERC on Form 714, there were 84 hours during the months of June through September during the years 2006-2017 when peak usage exceeded 99% of the annual coincident peak. Comparing 84 hours to 14 hours, it is clear that, despite the fact that extremely cold weather can result in extremely high levels of peak usage in some years, usage in excess of 99% of the annual peak still occurs far more frequently in the summer than in the winter.

OFFICIAL COPY

Jul 29 2019

The discrepancy between summer and winter is even more dramatic with respect to the highly elevated levels of peak usage which occur more frequently, and are also an important contributor to peak capacity costs. For instance, there were 783 hours during the summer when peak usage exceeded 95% of the annual peak and 2,479 hours when peak usage exceeded 90% of the annual peak. All told, usage in excess of 95% of the annual peak occurs 958% more frequently in the summer than in the winter, while usage in excess of 90% of the annual peak occurs 929% more frequently in the summer than in the winter, as shown in the following graph:



OFFICIAL COPY

Jul 29 2019

This data confirms that DEC and DEP are largely summer-peaking utilities, for the simple reason that the demand for electricity is much stronger in the summer than in the winter and very hot summer days are far more common than very cold winter days. Common sense and economic theory both suggest that a large share of capacity costs should be allocated to the summer. There is simply not any historical data to support the idea that it is appropriate to allocate all, or nearly all, capacity costs to the winter. Perhaps that is why Duke did not discuss any of this historical load data in its direct testimony, and instead referenced the loss of load estimates developed by its consultant, Astrapé.

Q. THE STIPULATION ALLOCATES CAPACITY COSTS TO MARCH BUT THE DATA YOU JUST DISCUSSED EXCLUDES MARCH. CAN YOU COMMENT ON THIS DISCREPANCY?

A. Yes. The historical load data does not support allocating capacity costs to March, which is why I left this month out of this discussion and the graphs that were included in my report. To state this even more clearly, there were no hours when peak usage exceeded 99% of the annual coincident peak and no hours when peak usage exceeded 95% of the annual peak during March during any of the years from 2006 through 2017. There were 11 hours when peak usage exceeded 90% of the annual peak in March during the years 2006-2017, but this number pales in comparison to the analogous figure of 2,479 hours during June through September of those same years.

OFFICIAL COPY

Jul 29 2019

Q. WHY DOES THE STIPULATION INCLUDE MARCH, YET EXCLUDE JUNE AND SEPTEMBER?

A. Duke chose not to give any weight to the historical data and instead focused entirely on the loss of load risk estimates provided by its consultant.

Q. WHY ARE THE LOSS OF LOAD ESTIMATES SO DIFFERENT FROM THE HISTORICAL DATA?

A. There are multiple factors contributing to this discrepancy. At least in part, the Astrapé loss of load risk estimates are inconsistent with the historical data because they were developed using unreliable assumptions and modeling techniques. These problems include flawed solar modeling, as discussed in my affidavit and my report, as well as the assumption that Duke's DSM programs would continue to primarily focus on summer peaks, instead of being transitioned to give equal or greater emphasis to winter peaks.

Q. CAN YOU BRIEFLY EXPLAIN THE PROBLEM WITH THE DSM ASSUMPTIONS?

A. Astrapé assumed Duke's time of day rates, energy efficiency efforts and other DSM programs will continue to primarily target summer peaks. If winter peaks were truly becoming the most serious problem, and loss of load risks in the summer were truly diminishing in importance to the point where 0% (DEP) to 10% (DEC) summer allocation factors were appropriate, it would no longer make sense to provide customers with an economic incentive to reduce their load during summer peak hours. Similarly, if winter loss of load risks

OFFICIAL COPY

Jul 29 2019

were truly increasing to the point where a 90% (DEC) to 100% (DEP) winter allocation factor were justified, it would be cost effective and appropriate to dramatically increase efforts to incentivize customers to reduce their load during winter peak hours. Neither DEC nor DEP have implemented these changes yet – calling into question how strongly they are committed to the argument they are now winter peaking utilities.

In any event, to the extent a shift in risk is occurring from summer to winter, this changing risk pattern should have been recognized by Astrapé in the assumptions it adopted with respect to the DSM programs. To maintain consistency with a changing risk profile, and to accurately estimate the actual loss of load risks that exist in each season, the DSM assumptions should have been modified to reflect the growing importance of winter risks and diminishing importance of summer risks. Succinctly stated, summer DSM programs would no longer be cost-effective if summer peaks were no longer important; this would eliminate any justification for maintaining these programs at the current levels, thereby negating any justification for assuming the status quo will be maintained.

If Astrapé had used more appropriate DSM assumptions, it would have estimated lower risk in the winter (due to more winter DSM) and more risk in the summer. With logically consistent DSM assumptions, the net result would still reflect some movement away from summer risk toward increased winter

OFFICIAL COPY
Jul 29 2019

risk, but the shift in risk would not be overstated, as it is with the assumptions used by Astrapé.

Q. IS THERE ANOTHER REASON YOU DISAGREE WITH THE SEASONAL ALLOCATION FACTORS IN THE STIPULATION?

A. Yes. In the 2018 IRP filings Duke explained that one of the primary motivations for shifting its primary focus to winter peaks is the increasing availability of solar capacity during the summer:

> In the past, loss of load risk was typically concentrated during the summer months and a summer reserve margin target provided adequate reserves in both the summer and winter periods. However, the incorporation of recent winter load data and the significant amount of solar penetration included in the 2016 study, shows that the majority of loss of load risk is now heavily concentrated during the winter period. The seasonal shift of LOLE to the winter period also increases as greater amounts of solar capacity are added to the system. Thus, increasing solar penetrations shift the planning process to a winter focus.[9]

This explanation confirms that Duke is evaluating loss of load risks primarily on a "net" basis, after taking into account the fact that solar capacity is helping meet the summer peaks and this benefit will increase as additional solar projects are connected to the grid. Solar capacity helps Duke serve peak levels of customer demand during hot summer afternoons; without this capacity loss of load risks would be much higher, and Duke would incur the cost of obtaining capacity from some other source.

---

[9] *Duke Energy Carolinas, LLC 2018 Integrated Resource Plan and 2018 REPS Compliance Plan*, Docket No. E-100, Sub 157 (September 5, 2018) ("DEC IRP"), p. 38; See also *Duke Energy Progress, LLC 2018 Integrated Resource Plan and 2018 REPS Compliance Plan*, Docket No. E-100, Sub 157 (September 5, 2018) ("DEP IRP"), p. 38.

OFFICIAL COPY
Jul 29 2019

Duke is evaluating loss of load risks on a "net" basis (after considering the benefits of solar capacity) in the IRP to help evaluate the optimal timing of when new generating capacity will need to be added. Whatever the merits of this approach in the context of the IRP, it is not appropriate to focus exclusively on "net" loss of load risks when developing the QF rates, as Duke is doing in this proceeding. By focusing on these "net" loss of load risks Duke is attempting to justify summer allocation factors that deny solar QFs any reasonable opportunity to be fully compensated for the capacity benefits they provide during the summer. The effect is to "take" capacity that is clearly needed to help protect against blackouts (or loss of load) during the summer, without fairly compensating the solar QFs that are providing this capacity. Not only is this unfair to QFs, it is inconsistent with PURPA and the FERC rules, which specify that QFs are supposed to be fully compensated for the capacity costs they enable utilities to avoid.

The unfairness of this approach is particularly evident in the case of existing solar QFs that invested in North Carolina on the understanding and expectation they would paid for the capacity they provide. It would clearly not be appropriate for Duke to continue to benefit from this capacity without providing fair payment for it. Yet, that would be the result of requiring them to renew their contracts using a seasonal allocation factor which assumes they will continue to provide this capacity but they will not be fairly compensated for it.

OFFICIAL COPY
Jul 29 2019

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

OFFICIAL COPY

Jul 29 2019

BY MR. SMITH:

Q And Dr. Johnson, did you prepare a summary of your testimony?

A Yes.

Q Thank you. Can you please read that now?

A Yes. My affidavit and direct testimony identify numerous problems with the Utilities' proposals with respect to the issues falling within the scope of this hearing. In this summary I will briefly highlight a few examples.

The report attached to my affidavit identified and discussed multiple problems with the solar energy modeling that underpins Duke's quantification of ancillary services costs of integrating QF solar and Duke's proposed solar integration charge. The inaccurate modeling of net system load resulted in an overstatement of the impact on ancillary service costs which was further compounded by the failure to develop a balanced consideration of both costs and benefits of solar integration.

There are several aspects of Duke's proposals in this proceeding that could have the effect of largely or entirely eliminating any payment for QF capacity, including the way a capacity need is defined, the assumed

OFFICIAL COPY

Jul 29 2019

in-service date, and the seasonal allocation factor.

In my testimony I demonstrate that the assumed in-service date used in the avoided cost and QF rate calculations is inaccurate and biased against QFs. The historical data suggests most new projects falling within the current biennial time frame will not be energized until 2021; very few, if any, will be energized on or before January 1, 2019, which is the date assumed by the Utilities. This inaccurate assumption leads to various distortions in the calculations, particularly with respect to fuel costs and the use of zeros in the capacity cost calculations.

The Commission should require a more realistic assumption which would correspond to having roughly half the QFs with an actual in-service date before and half the QFs with an actual in-service date after the assumed date. An even more accurate approach would be for the Commission to require the Utilities to publish a schedule of rates or a formula that varies over time so that each QF signing a contract during the 2019-2020 biennial period will receive the appropriate rate based on its actual in-service date.

The Stipulation filed by Duke and the Public Staff on April 18, 2019 provides a significant

OFFICIAL COPY

Jul 29 2019

improvement to the energy rate design with respect to seasonal and hourly patterns, but I recommend the Commission consider going even further in this direction by requiring the Utilities to calculate separate rates for each hour of each month. These rates can be succinctly displayed in a simple matrix of 12 columns representing months, and 24 rows representing each hour of the day. While this might seem more complex, it would actually be easier for QFs to analyze and respond to this 12 by 24 matrix than the less granular design used in the Stipulation.

Furthermore, the Stipulation does not offer any improvements with respect to avoided capacity costs or with respect to geography and weather fluctuations. The Commission should require movement toward more accurately reflecting geographic cost differences and applying real-time pricing during extreme conditions the relatively small number of hours when system costs are extremely high or extremely low. More specifically, the Commission should require the Utilities to develop detailed plans for implementing geographically granular rates and real-time pricing during a small number of extremely high and low cost hours for the Commission's consideration in a future proceeding.

OFFICIAL COPY

Jul 29 2019

Finally, I recommend the Commission reject the seasonal allocation factors used in the Stipulation which would almost entirely eliminate capacity payments during the summer, despite the fact that DEC and DEP are both primarily summer peaking utilities. In fact, usage in excess of 95 percent of the annual peak occurs 958 percent more frequently in the summer than in the winter, while usage in excess of 90 percent of the annual peak occurs 929 percent more frequently in the summer than in the winter. Common sense and economic theory both suggest that a large share of capacity costs should be allocated to the summer.

The need for a more appropriate seasonal allocation approach is particularly strong in the case of existing solar QFs that invested in North Carolina on the understanding and expectation they would be paid for the capacity they provide. If the proposed seasonal allocation is applied to renewal contracts signed by existing QFs, Duke will continue to fully benefit from the existing QF capacity, but the QFs will no longer be paid for their capacity once their existing contracts end. This is fundamentally unfair and inconsistent with the requirements of PURPA and the FERC rules. Regardless of how the seasonal allocation, in-service date, and

OFFICIAL COPY

Jul 29 2019

capacity need issues are resolved with respect to new QFs, I recommend the Commission include language in its final order which acknowledges that QFs with contracts expiring between now and 2028 are fulfilling an existing capacity need, and they will continue to be fully compensated for the capacity costs they are helping the Utilities avoid if they sign a renewal contract.

MR. SMITH: Thank you, Dr. Johnson. Madam Chair, Dr. Johnson is now available for cross examination.

CHAIR MITCHELL: Thank you.

MR. DODGE: Madam Chair, the Public Staff originally did request some time to cross examine Mr. Johnson, but we're going to pass on that time today.

CHAIR MITCHELL: Okay. Thank you, Mr. Dodge. Any other Intervenor wishing to -- okay. Mr. Breitschwerdt.

MR. BREITSCHWERDT: Thank you.

CROSS EXAMINATION BY MR. BREITSCHWERDT:

Q Good afternoon, Dr. Johnson.

A Good afternoon.

Q So a couple of questions for you. I'm going to start with where you ended with the discussion of renewing QFs and the capacity value they provide. In

OFFICIAL COPY

Jul 29 2019

page 12 of your testimony you speak to the point that -- this is starting on line 12 -- that making capacity payments to existing QFs contingent upon a finding that additional new capacity is needed is inconsistent with -- well, you say this structure, which I think you're referencing the general PURPA framework. Is that a fair characterization?

A Yes.

Q And the Duke Companies' position in this proceeding is that any QF that makes a legally enforceable commitment to sell its output should be recognized at providing capacity for the specified term of that contract. Do you agree with that?

A I don't think they dispute the fact that the QF should be compensated.

COMMISSIONER GRAY: Sir, could you pull that microphone up some?

THE WITNESS: Sure.

MR. BREITSCHWERDT: Yes, sir.

A If I'm understanding correctly --

MR. BREITSCHWERDT: It wasn't me this time.

A If I'm understanding your question correctly, I don't think Duke disputes the fact that QFs are entitled to be paid for the capacity they provide over a

OFFICIAL COPY

Jul 29 2019

contractual commitment period.

Q And then at the conclusion of that contractual commitment period Duke's position is that QFs, like all other wholesale customers, are no longer considered capacity resources for purposes of IRP planning and have the opportunity to enter into a new contract at the Utilities' most current updated avoided cost; is that correct?

A I don't think that accurately states the effect of what Duke seems to be proposing. The way I would state it is Duke is proposing a mechanism and a system which would preclude the QF from being fully compensated for the capacity they have been providing in the future time period, or put another way, it systematically prevents the QF from being paid for the capacity benefits they're providing going forward.

Q Is there anything in PURPA that differentiates -- and you speak to PURPA, so hopefully we're not getting into legal conclusions that you can't answer, but that differentiates between a new QF and an existing QF in terms of providing capacity value when they establish a legally enforceable obligation? Are you familiar with that term?

A I am familiar with the term. And your question

OFFICIAL COPY

Jul 29 2019

is, is there something in PURPA that distinguishes between old and new QFs? I don't think it goes to that question, so there may be some language in PURPA or in the FERC rules that indirectly touch on this issue, but I don't recall seeing anything that explicitly distinguishes.

But on the other hand, the FERC rules in PURPA doesn't, for example, explicitly say anything about demanding that the QF continue to provide capacity, but has two or three or four years in which they're not paid anything because of a provision that Duke is interpreting in a state law, just as one example.

Similarly, there's nothing in the FERC rules that say what should happen if a large block of QF capacity is providing summer capacity and deferring the need for capacity in the summer, and it reaches the point a consultant prepares a study in which they claim that all the loss of load risk is now in the winter, just doesn't go down to that level of detail, that the correctness or appropriateness of those kind of interpretations is precisely why these issues are being disputed here at this proceeding.

Q And you reference a state law. Which state law are you referring to specifically?

OFFICIAL COPY

Jul 29 2019

A 589.

Q Okay. And would you agree that that's -- the state law is 62-156 of the North Carolina General Statutes, which is North Carolina's implementation of PURPA which was amended in House Bill 589?

A I -- I don't recall the exact number as it's listed in a statute, but it sounds similar to something I recall seeing. I certainly have no reason to dispute the number you just said to me. I just don't remember it.

Q That's all right.

MR. BREITSCHWERDT: May I approach, Chair Mitchell?

CHAIR MITCHELL: Yes, you may.

Q So what I have provided to you, Mr. Kirby -- strike that. You're not Mr. Kirby. Spent a lot of time with Mr. Kirby the last day, so -- Dr. Johnson, is House Bill 329; do you see that?

A Yes.

Q And this is a ratified bill which has been passed by both houses of the General Assembly, and has been presented to the Governor. Would you accept that, subject to check?

A If you'll tell me how to check it, sure.

Q Well, I think you could check it by going to

OFFICIAL COPY

Jul 29 2019

the General Assembly's website and punching in 329 and it would be there, so I'll --

A And this is currently -- currently at a stage of pending the Governor's signature?

Q That's correct.

A Okay.

Q And so to -- to the conversation we were having about the obligation to pay QFs for capacity when the Utility has a capacity need, if you would turn to page 5 of this legislation, please. I'm sorry. Strike that. Page 4. It's the last page.

A Okay.

Q So Section 3.(a) of the legislation amends 62-156(b)(3), and it specifically speaks to the availability and reliability of power. And if you would accept that that section was modified through House Bill 589, which is the legislation spoken of in your testimony, it provides as a matter of state law that "A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to 62-110.1(c) has identified a projected capacity need to serve system load and the identified need could be met by the type small power producer based upon its availability and reliability of

OFFICIAL COPY

Jul 29 2019

power..." Do you see where I read that in the middle of that --

A Yes.

Q -- section?

A Yes.

Q And would you agree with me that the manner in which Duke Energy has quantified its avoided capacity rates for purposes of this proceeding are reflective of that?

A Not necessarily. I would agree that Duke's position claims that their proposed approach is consistent with state law, including the way you've just read this, but the meaning of these provisions is something that I don't think is totally unambiguous. So whether or not that is an appropriate interpretation is a question to be determined.

Q Well, is it fair to say that Duke has identified its next capacity need in Duke Energy Progress in 2020 and Duke Energy Carolinas in 2028? Would you agree with that?

A I would agree that those are the claims they're making or the -- the way they are articulating it. Ultimately, the question for the Commission is twofold, the factual question of whether there's -- all those

OFFICIAL COPY

Jul 29 2019

capacity needs in the intervening years are appropriately dismissed and not used in arriving at the final conclusion as to the timing of the capacity need, giving an example being the upgrade to the pump storage units. That -- that clearly goes beyond simply routinely replacing existing facilities and its upgrading the capacity of those. That would suggest to me there is a capacity need, but the Commission may ultimately conclude, no, that that is not indicative of a capacity need. That's one issue in terms of the facts of whether or not the need is there.

Q Okay.

A The second issue being if a QF is meeting an existing capacity need, how does that play into this language?

Q That's -- excellent point, and that's right where I wanted to take you, so thank you for that, so --

CHAIR MITCHELL: Mr. Breitschwerdt, I'm going to interrupt you just briefly. Dr. Johnson, please speak into your microphone. We're having a hard time hearing you up here, and I imagine the folks in the back of the room cannot hear you at all.

THE WITNESS: Okay. Thank you.

Q So you mentioned how to quantify it for an

OFFICIAL COPY

Jul 29 2019

existing QF that's providing an existing capacity need. If you'll accept that the structure of this legislation is that underlined language is amending state law, and the language that's not underlined or struck through is state law as it exists today. Do you see that, or will you accept that?

A Yes.

Q Thank you. So on that basis, the underlined language at the end of Section 3 speaks to hydro power small power producers with power purchase agreements in effect on July 27, 2017, which you'll accept, subject to check, is the date that House Bill 589 was enacted into law, and the renewal of such power purchase agreements, if the hydroelectric small power producer's facility is equal to 5 MW or less. Did I read that generally correctly?

A Probably. I'm sorry. I --

Q That's all right.

A I didn't quite follow how your discussion of this sentence related to the earlier preface to --

Q So --

A -- your question, but --

Q So the -- the concept here being that under state law we've established that a projected capacity

OFFICIAL COPY

Jul 29 2019

need determines how you quantify avoided capacity costs for all QFs, and this amends that language to provide that a small hydro power producing QF that is renewing its Power Purchase Agreement would be able to continue to be receiving the capacity value that you ascribe should be provided to all small power producers.

MR. SMITH: I'm going to object. The bill, as far as I know, hasn't been signed by the Governor. It's not current law in North Carolina.

MR. BREITSCHWERDT: I'll -- I'll accept that to be the case, and I think the material point is that in terms of renewing a PPA, this contemplates what -- the capacity value that is expected for small power producers, separate and apart from a special class of small power producers which are hydro facilities that are legacy facilities 5 MW or less.

CHAIR MITCHELL: Okay. I'm going to overrule the objection, but I'm going to ask that you break that -- break that question up into smaller questions so that Dr. Johnson understands the question and then can answer them serially.

MR. BREITSCHWERDT: Yes, ma'am.

Q So this exception to the general rule provides for hydro QFs effectively what your policy position would

OFFICIAL COPY

Jul 29 2019

be for all small power producers, meaning that they have the right to continue to receive capacity value in the year their contract renews because they're, as a matter of state law, not subject to the Utility's IRP's determination of the next avoidable capacity need.

A Well, I don't agree with that statement, in part because I think you're misinterpreting my testimony, so I don't want to agree to a statement that implies an interpretation of my testimony that isn't valid.

Q Okay. Well, would you agree with me that Section 3.(b) further clearly states that this exception for small hydro small power producers shall not be construed to affect the applicability of the general provisions for any other type of small power producer?

A I think it's reasonable to assume -- I'm not sure, but it's reasonable to assume, just looking at this language, that if there is a special provision for hydro power, that that special provision doesn't apply to cogenerators or solar or wind or whatever.

Q And --

A I -- I get that, but that's sort of not the question. There's these other questions that are still up in the air as to what is the meaning of the underlying language about a future capacity need when you're

OFFICIAL COPY

Jul 29 2019

applying it to the context of existing capacity needs. The language in the law that I'm familiar with deals with future capacity needs, and until that's ultimately resolved, which may take years of thinking about it and working through it and possibly litigation or whatever, eventually that may become very clear, but at least for me as a non-lawyer, looking at it, saying that's not clear what the Legislature had in mind because they added the word future. And so it's future, and yet we're talking -- in the context of your question we're talking about existing QFs that are meeting an existing capacity need.

A similar example would be back to the pump storage units, those pump storage units are meeting both an existing and a future need. The existing capacity meets the existing need. The upgrade that you've gotten authorization to put in rate base will meet a future need. To me, in my mind, there's a distinction there, and in that case the facility is meeting both of them. Again, you've got the renewal of the existing capacity and the upgrade. Analogously, you have a distinction of existing QFs that are meeting an existing need. What the Commi--- what the Legislature had in mind when adding the word future is not clear to me.

OFFICIAL COPY

Jul 29 2019

Q Would you agree with me that this provides that a renewal of an existing PPA for a small power producer will enable them to obtain that capacity value under a new PPA, and that's not contemplated for other types of small power producers?

MR. LEVITAS: Objection. Madam Chair, I'm -- I'm not sure why Mr. Mr. Breitschwerdt is being allowed to pursue this line of questioning, but Section 3.(b) of this bill was added at the specific request of the solar industry to be sure that the amendment and the underlying language added for hydro was not interpreted to -- to resolve or influence the issue before you in this case, and Mr. Breitschwerdt is trying to make exactly that point and to bootstrap that language into answering the question that's before you about how existing solar QFs should be treated.

MR. BREITSCHWERDT: I think the legislation speaks for itself, and that's all the questions that I have.

CHAIR MITCHELL: Dominion?

MR. DANTONIO: No cross from Dominion.

MR. SMITH: No redirect.

CHAIR MITCHELL: Any questions by the Commission?

OFFICIAL COPY

Jul 29 2019

(No response.)

CHAIR MITCHELL: Thank you, Dr. Johnson, for coming.

THE WITNESS: Thank you.

CHAIR MITCHELL: You're dismissed.

MR. BREITSCHWERDT: Chair Mitchell, I will move this as Duke Energy Johnson Cross Exhibit Number 1, please.

CHAIR MITCHELL: So let's -- let's mark it first. You'd like to mark it as Duke -- DEC/DEP --

MR. BREITSCHWERDT: -- Johnson Cross Exhibit 1, please.

CHAIR MITCHELL: The exhibit will be so marked. You want to move it into --

MR. BREITSCHWERDT: I would.

CHAIR MITCHELL: Okay. Without objection --

MR. SMITH: I would like to object because I -- I'm still failing to see the relevance of it in terms of the fact that it's not current law, so that's -- that's my objection.

MR. BREITSCHWERDT: I'll move it as a ratified bill that is not current law.

MR. SMITH: All right. That's sufficient for me.

OFFICIAL COPY

Jul 29 2019

CHAIR MITCHELL: Okay. The record will reflect that this ratified bill has not yet been executed by the governor.

MR. BREITSCHWERDT: That's correct.

CHAIR MITCHELL: So with that, the motion is allowed.

(Whereupon, DEC/DEP Johnson Cross Exhibit 1 was marked for identification and admitted into evidence.)

MS. BOWEN: Madam Chair, the Southern Alliance for Clean Energy would now like to call Devi Glick to the stand.

CHAIR MITCHELL: Good afternoon, Ms. Glick. Let's go ahead and get you sworn in.

DEVI GLICK: Having been duly sworn, Testified as follows:

DIRECT EXAMINATION BY MS. BOWEN:

Q Good afternoon, Ms. Glick. Please state your name and your business address for the record.

A Devi Glick, 485 Massachusetts Avenue, Cambridge, Massachusetts.

Q Thank you. And did you cause to be prefiled in this proceeding direct testimony?

OFFICIAL COPY

Jul 29 2019

A I did.

Q And do you have any changes or corrections to your prefiled testimony?

A I do. I have one typo correction on page 11, line 4. It reads rate, and it should say rare.

Q Okay. Other than that correction, if the questions put to you in your testimony were asked at the hearing today, would your answers be the same?

A They would be, yes.

Q Okay. And was the exhibit to your testimony prepared by you or under your direction?

A Yes.

MS. BOWEN: Madam Chair, I would move Ms. Glick's prefiled direct testimony be entered into the record as if given orally from the stand and have the exhibits attached to her testimony identified as premarked exhibits, Glick Exhibit A.

CHAIR MITCHELL: Hearing no objection, the motion is allowed.

OFFICIAL COPY

Jul 29 2019

(Whereupon, the prefiled responsive testimony of Devi Glick, as corrected, was copied into the record as if given orally from the stand.)

(Whereupon, Glick Exhibit A was identified as premarked.)

OFFICIAL COPY

Jul 29 2019

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address for the record.

A. My name is Devi Glick. I work at Synapse Energy Economics, Inc., located at 485 Massachusetts Avenue in Cambridge, Massachusetts.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and natural gas industry regulation, planning, and analysis. Our work covers a range of issues, including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, the U.S. Department of Energy, the U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 30 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan; a bachelor's degree in environmental studies from Middlebury College; and more than six years of professional experience as a consultant, researcher, and analyst.

At Synapse, and previously at Rocky Mountain Institute, I have focused on a wide range of energy and electricity issues, including: utility resource planning, distributed energy resource valuation, energy efficiency program impact analysis, and rate design effectiveness. For this work, I develop in-house models and perform analysis using industry-standard models.

OFFICIAL COPY

Jul 29 2019

On topics related to the costs and benefits of distributed generation, I have submitted written testimony and appeared in person before the Public Service Commission of South Carolina in a number of dockets relating to the avoided costs associated with solar photovoltaics ("PV"). Additionally, I have co-authored two studies reviewing valuation methodologies for solar PV. These studies continue to be frequently cited in public utility proceedings for their recommendations around distributed energy resource pricing and rate design.

My CV is attached as Glick Exhibit A.

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

A. I am testifying on behalf of Southern Alliance for Clean Energy ("SACE").

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

A. No.

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

A. On June 14, 2019, the Commission issued an *Order Requiring Supplemental Testimony and Allowing Responsive Testimony*. The order requested that parties address the avoided cost rate schedule and contract terms and conditions that an existing Qualifying Facility ("QF") proposing to add battery storage to its electric generating facility would receive under North Carolina's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The primary purpose of my testimony is to respond to Duke Energy Carolinas' ("DEC") and Duke Energy Progress' ("DEP"; together "Duke Energy" or "the Companies") joint supplemental testimony. Dominion has not proposed any changes to rates or

OFFICIAL COPY

Jul 29 2019

terms of existing QFs seeking to add battery storage, therefore I will not specifically respond to Dominion's supplemental testimony.[1]

II. BACKGROUND AND SUMMARY

Q. Please summarize your reaction to Duke Energy's proposed "material modification" language and the Companies' position on the avoided cost rate that should apply.

A. Duke Energy's proposed language on "material modification" to existing QFs grants Duke Energy "sole discretion" to deny the addition of energy storage if the QF seeks to retain its pre-existing standard offer Power Purchase Agreement ("PPA").[2] By doing so, this proposal actively discourages the addition of battery storage, a capacity resource that would add significant value to the system. This outcome is undesirable for ratepayers and grants the utility unnecessary and unwarranted control over a QF.

Duke Energy has stated that the production profiles of solar QFs do not coincide with system demand peaks.[3] Battery storage firms up solar PV capacity and allows the output from solar QFs to shift to align with these system peaks. Duke Energy claims that the ability of battery storage to shift the profile of production under a QF's existing avoided cost rate increases payments to the QF and therefore increases costs to ratepayers, due in part to the shift in peak time periods over the years. However, if the peak time periods in the QF's existing contract do not align with Duke Energy's current system peaks, the Companies should propose new peak time periods for QFs that add battery storage.

---

[1] Dominion's position on the avoided cost rate schedule and contract terms and conditions is very similar to the position expressed by Duke Energy.

[2] Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits at p. 35, Docket E-100 Sub 158 (hereinafter "Duke Energy Initial Statement").

[3] Duke Energy states that Solar QFs lack coincidence with customers highest demand periods. Duke Energy Initial Statement at p. 24.

Specifically, the Companies' proposal should: (1) pay QFs their existing rates and (2) shift the premium pricing time periods to align with current system peak.

By shifting production to align with current system peaks, the utility avoids greater cost and receives greater value from the QF. The utility can lower operational costs by not running its most expensive peaking resources and by gaining the ancillary services provided by battery storage.[4] Additionally, the utility can lower system costs by deferring or eliminating the need to build new peaking capacity resources, and even transmission or distribution infrastructure. Therefore, the Companies' claim that allowing existing QFs to add storage while maintaining their PPA would disadvantage ratepayers and violate PURPA is unsupported.

Q. Please provide additional context for battery storage compensation as a QF under PURPA.

A. In *Luz Development and Financial Corp.*, the Federal Energy Regulatory Commission ("FERC") clarified that battery storage is eligible for QF status if its primary energy source is "one of those contemplated by the statue…e.g., biomass, waste, renewable resources, geothermal resources, or any combination thereof."[5] Solar PV is a renewable resource, therefore battery storage added to an existing solar QF is QF eligible under PURPA.

Q. Can the utility restrict operation of a solar QF that adds battery storage under PURPA?

A. So long as the QF discharges power onto the grid (1) consistent with PURPA and the QF's interconnection agreement, and (2) at a level that does not surpass its current AC generating capacity, the QF should be permitted to operate with storage under its existing contract. By adding a DC-coupled battery storage

[4] The utility does not have direct control over the battery under typical QF system design, however rate designs can incent operators to provide ancillary services rather than just energy to the grid.

[5] 51 FERC ¶ 61,078, at 61,172 (1990).

OFFICIAL COPY
Jul 29 2019

274

OFFICIAL COPY

Jul 29 2019

system to the existing QF, the QF does not increase its AC capacity, and the battery should be considered part of the QF. Therefore, the utility has no reasonable basis to regulate the operation of individual components on the operator side of the meter.

The QF should also be entitled to reasonably modify operations within the terms of its existing contract. To understand why, consider an example from a different QF resource: a waste-steam plant. If a manufacturing plant changed its factory hours to produce waste steam at a higher-valued generating time, Duke Energy would have no basis to require the factory to shift operating hours back to the original timeframe. A solar QF seeking to add battery storage and shift its generation profile should be treated no differently.

III. MATERIAL MODIFICATIONS LANGUAGE IN THE PPA TERMS AND CONDITIONS

Q. Please summarize the material modifications language Duke Energy has proposed adding to the standard offer PPA contracts as it relates to the integration of battery storage to an existing QF.

A. Duke Energy proposed new language to its Schedule PP Terms and Conditions which allows the Companies to "either terminate the Agreement or suspend purchases of electricity from the Seller" based on "any material modification to the Facility without the Duke's consent or otherwise delivering energy in excess of the estimated annual energy production of the facility."[6]

Additionally, Duke Energy provided that "any material modification to the Facility, including without limitation, a change in the AC or DC output capacity of the Facility or the addition of energy storage capability shall require the prior written consent of the Company, which may be withheld in the Company's sole

[6] Duke Energy Initial Statement, DEC Exhibit 4 at p. 2; Duke Energy Initial Statement, DEP Exhibit 4 at p. 2.

discretion, and shall not be effective until memorialized in an amendment executed by the Company and the Seller."[7]

Finally, Duke Energy provided an Energy Storage Protocol in the Companies' Reply Comments to provide clarity on how battery storage integrated with QFs is allowed to interact with the grid.[8]

Q What is the Companies' position regarding the avoided cost rate that an existing QF adding battery storage should receive?

A. Witness Snider states that an existing QF that adds battery storage should be required to enter a new or modified PPA at the Companies' current avoided-cost rate.[9] The Companies' current avoided cost rates are lower than previous avoided cost rates for existing QFs.[10]

Q. How does Duke Energy seek to justify the Companies' position that an existing QF adding battery storage should be subject to a lower, new avoided cost rate?

A. The Companies claim that it will be "inequitable and inconsistent with PURPA" to allow QFs with existing contracts to: (1) increase their generators' size; (2) increase their capability to produce energy in more hours of the day; or (3) shift their energy production to make additional or modified sales at rates that are much higher than the Companies' current avoided cost rates.[11]

Duke Energy goes on to state that allowing QFs to integrate battery storage (or other technology) that alters a QF's energy output or shifts its power production under existing avoided cost rates would result in increased payments

---

[7] Duke Energy Initial Statement, DEC Exhibit 4 at 5; Duke Energy Initial Statement, DEP Exhibit 4 at p. 4.

[8] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC. Reply Comments at p. 150, Docket No. E-100, Sub 158 (hereinafter "Duke Energy Reply Comments").

[9] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. E-100, Sub 158, Supplemental Testimony of Glen A. Snider at p. 5 ("hereinafter "Supplemental Testimony of Glen Snider").

[10] *Id.* at pp. 7-8.

[11] *Id.* at p. 7.

OFFICIAL COPY
Jul 29 2019

OFFICIAL COPY

Jul 29 2019

to QFs that exceed current avoided cost rates.[12] According to Duke Energy, this in turn would burden customers with the incremental charges.

Q. How do you respond to Duke Energy's concerns?

A. The Companies' claims are unfounded and unsupported by Witness Snider's testimony. There is no change to the avoided cost *rates* that apply to a QF with battery storage capability. Only the total payments would increase, in line with increased value provided by the battery storage addition. The addition of DC-coupled battery storage does not increase the AC capacity of a QF. Additionally, shifting production to different hours in the day can actually benefit the system by enabling QF production to align with the hours of highest system need. Finally, QFs are receiving higher avoided cost payments for the energy provided during premium pricing windows because they are offering higher value to the system and lowering system costs during those hours. If the existing premium pricing periods do not fully align QF generation with peak system demand, the utility should propose updated pricing periods for QFs that add battery storage that award the highest payments during current peak hours.

I will explore each of these three main points regarding (1) generation quantity; (2) generation profile; and (3) and system impacts, including generation payments, in detail in the sections that follow.

IV. GENERATION QUANTITY AND PROFILE

Q. Please explain how battery storage paired with a solar QF will alter a QF's energy output.

A. If a QF is sized at or below contract capacity specified in the PPA,[13] the addition of battery storage will generally decrease the total quantity of electricity

---

[12] Supplemental Testimony of Glen Snider at p. 8.

[13] *See* Duke Energy Joint Initial Statement, DEC Exhibit 1 at p. 1; Duke Energy Joint Initial Statement, DEP Exhibit 1 at p. 2.

OFFICIAL COPY

Jul 29 2019

dispatched to the grid. The round-trip efficiency of a battery, or the fraction of energy put into the battery that can be retrieved, is typically around 80–90 percent for a lithium-ion battery.[14] This means that 10-20 percent of energy is lost in the process of charging and discharging the battery (additionally, the battery storage system might have additional parasitic load for cooling). This lost electricity is no longer available to sell to the grid. Thus, for a QF sized at or below contract capacity, the addition of battery storage will generally decrease the QF's overall electricity output, though it does enable the shift in electricity to better align with peak demand.[15]

Q. Please explain how battery storage paired with a solar QF will shift the profile of power production.

A solar QF *without* battery storage will send electricity to the grid whenever the sun is shining. A QF *with* battery storage can easily shift output and will likely discharge some or all of the electricity generated to the grid during the hours when it receives premium pricing, set at times of peak demand. If there are multiple pricing tiers, the operator will act to co-optimize across multiple time periods to maximize its profit. As long as the pricing tiers are properly aligned with peak demand, the QFs should be driven to discharge during peak hours when electricity is most needed and otherwise most expensive for the utility to generate.

Q. Does system peak sometimes falls outside of the premium pricing window in the QF's contract?

A. QFs on contracts that are more than a few years old may have premium pricing windows that do not completely align with current system peaks. This shift in the peak is in part because the QFs are providing capacity during the periods that

---

[14] The range varies depending on the battery's chemistry and the QF's operation.

[15] QFs that currently clip electricity and are not able to dispatch all electricity to the grid under current rates will be able to use the battery storage to store the clipped electricity for sale to the utility at a later time, and thus may be able to maintain existing generation output levels rather than decreasing total output.

OFFICIAL COPY

Jul 29 2019

would be peaks were it not for the deployment of solar PV, much of which has occurred because PURPA has provided a pathway for QF development.

Q. Can more granular pricing and rate design help the system maximize the value provided by battery storage?

Yes, as mentioned above, updated time periods, or other more granular price signals or incentives, can further align QF premium pricing windows with current system peaks. Duke Energy treats the rate options for existing QFs as binary: either stay on the previous contract rates without storage or enter into new PPAs on the current avoided cost rate if seeking to add storage.[16]

In reality, the Companies have the opportunity to offer QFs modified contracts that (1) pay QFs their existing rates; (2) shift the premium pricing time periods to align with current system peak.

QFs should be amenable to considering such a change in contract provided they know the pricing periods in advance and can size their batteries to maximize revenue from their QF systems during the new pricing windows. Failure by the utility to explore different terms with existing QFs that could harness storage options to lower overall system costs ultimately disadvantages ratepayers.

[16] Supplemental Testimony of Glen Snider at p. 8.

OFFICIAL COPY

Jul 29 2019

V. SYSTEM IMPACTS AND GENERATION PAYMENTS

Q. How does Duke Energy support its argument that adding battery storage to solar QFs on their existing rates will increase system costs?

A. Duke Energy's argument regarding increased system costs from adding battery storage to existing QFs can be broken down into two parts: (1) current system peaks may not align with system peaks from existing QF contracts; (2) the avoided cost rate for existing QFs is higher than the Companies' current avoided cost rates, therefore existing QFs will be overcompensated. On the first issue of system peak, I have clearly outlined above how new premium pricing periods can align existing QF generation with current system peaks.

On the second issue regarding the avoided cost rates for existing QFs, Duke Energy has not demonstrated that an existing QF rate exceeds the incremental cost to the electric system of the utility providing the capacity and energy that would be needed but for the QF with integrated battery storage. Specifically, the Companies have not demonstrated that the current avoided cost rate captures all values (including ancillary services, transmission and distribution capacity, and even energy and generation capacity) provided by a solar QF with battery storage.[17]

Q. How will the addition of battery storage to an existing solar QF impact the utility?

A. Battery storage impacts operational and planning decisions for the utility. First, the peaking capacity provided by battery storage will decrease operational costs by reducing the need to run the most expensive resources during peak times. Second, battery storage can provide ancillary services that the utility needs to

[17] Given the short timeframe for response comments we were not able to quantify the net benefits from adding battery storage to solar QFs.. However, the impacts are quantifiable though production cost and capacity expansion modeling, as well as a close examination of how well the current avoided cost rates capture the values provided by a QF with battery storage, including ancillary services, avoided transmission and distribution capacity, and other environmental benefits.

OFFICIAL COPY

Jul 29 2019

operate the grid. These values are not currently included in Duke Energy's avoided cost rates. Finally, battery storage has the potential to obviate, reduce, or defer the need for the utility to invest in large, expensive, capital generation projects that are driven by the need to meet peak demand (particularly rate winter peaking events), or even certain distribution and transmission investments (which once again are not fully captured in current avoided cost rates).

Currently, the Companies compensate solar QFs a small amount of their capacity contribution based on the argument that: (1) the utility systems are currently dual or winter peaking and; (2) solar generation does not align with winter peaks, which begin in the morning before the sun rises. However, a QF with battery storage can contribute capacity during winter mornings, and therefore the capacity contribution value should be significantly higher for solar QFs with storage for planning purposes.

Q. How will the integration of battery storage with existing QFs impact ratepayers?

A. As mentioned above, battery storage paired with a solar QF can increase the value provided by the QFs. When the utility operates an expensive peaking resource or invests capital in a new peaking resource (or even new transmission and distribution equipment), the costs and any associated future risks are typically passed on to the ratepayers. However, when battery storage is added to existing QFs, the ratepayers gains peaking capacity for at most the incremental cost of the peak versus off-peak avoided cost rate.[18]

Q. Will there be any negative impacts on grid reliability from the integration of battery storage with existing QFs?

A. Battery storage paired with a solar QF will increase grid reliability by (1) allowing a solar QF to store electricity when need is lower and dispatch to the

---

[18] The additional services and values provided by battery storage reduces the incremental cost. Additionally, the contract length for a QF is significantly less than the 25–30 year typical amortization period for a new peaking plant.

OFFICIAL COPY

Jul 29 2019

grid when need is higher; and (2) allowing the operator to limit and control the QF's ramp rates in accordance with an Energy Storage Protocol when operating the battery.

Duke Energy performs its System Impact Studies assuming a QF is operating at maximum Physical Export Capability during the entire study period (i.e., daylight hours of 9:00 am–5:00 pm). These studies determine whether the addition of a QF will impact the grid under the most extreme output conditions. As long as the QF is dispatching power during this same time block studied in the System Impact Study (and in accordance with ramping requirements), the QF is safely operating according to the utility's own system impact studies.[19]

In almost every case, a QF producing power during system peak reduces system cost. However, if the system peak load is outside of the study window, the QF may not be permitted to operate due to the limits of its System Impact Study. It is in the best interest of the ratepayers for the utility to expedite a study of system impacts with an expanded study window when a QF requests to add battery storage to its contract so that QFs can provide power during times of the system's highest need.

Finally, the Companies have proposed an Energy Storage Protocol which outlines measures that affect reliability and system performance. These measures include ramp rates, discharge profile, installation location in relation to the inverter, and curtailment requirements, which control certain aspects of battery operation. This protocol, if my concerns described below are addressed, provides an opportunity for QFs to provide a higher net value to the grid by avoiding fast ramps that could otherwise cause grid integration challenges.

[19] Reliability and system impact concerns were the subject of NC Docket E-100, Sub 101, Revision to Interconnection Standards.

OFFICIAL COPY

Jul 29 2019

Q. What specifically are your concerns with Duke Energy's Proposed Energy Storage Protocol?

A. I have two main concerns with the protocol. First, the protocol should constrain the operation of the QF, not its sub-components. In Items 4, 5, and 6 of the protocol,[20] it should be immaterial to the Companies where the power is coming from. Additionally, Duke Energy's metering currently cannot tell which part of the facility is supplying power so it unclear how this could be enforced.

Second, the requirement in Item 7 to maintain output level at the highest possible output level is inappropriate.[21,22] The QF compensation and operation structure should be fair to any QF that an operator wants to propose, whether that is a 1-hour battery to control ramping and avoid a solar integration charge, a 4-hour battery to discharge during premium period, or any other design. With Item 7 in place, the Protocol effectively favors particular system designs, rather than simply ensuring that the QF is fairly compensated for its output, regardless of its design.

This requirement also will sub-optimally limit system discharge at low levels. During a winter morning when winter peak system demand begins before sunrise, for example, the battery can begin to discharge at the beginning of a morning premium peak period. However, before the sun comes up system discharge will likely be limited by the highest sustained level of battery discharge. Depending on battery size, the protocol as it stands today could require the QF to curtail its solar generation as the sun rises in order to keep system output flat during the premium peak. This is the case regardless of whether the system will benefit from an increased level of generation from the QF as the sun comes up and can generate more electricity.

---

[20] Duke Energy Reply Comments, Exhibit 6 at p. 1.

[21] *Id.*

[22] PURPA does not grant the utility control over when a QF produces electricity, how much to produce, or what the production profile should look like (except in certain emergency situations).

OFFICIAL COPY
Jul 29 2019

VI. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions regarding Duke Energy's proposed language on material modifications.

A. My conclusions are as follows:

1. Duke Energy's proposal actively discourages the addition of battery storage, a capacity resource that would add significant value to the system and to ratepayers by firming up solar PV variability and allowing the shifting of output from solar QFs to further align with system peak. This shifting can address the criticism of solar PV, expressed by Duke Energy, that the typical solar generation profile is not coincident with certain peak demand periods.[23]

2. The Companies' claim that allowing QFs to integrate battery storage will increase costs to customers is inaccurate and ignores the significant potential increased value to the system provided by storage that can both firm capacity and align QF power output with system-wide capacity needs.

3. The proposed Energy Storage Protocol is imprecisely targeted at QF system sub-components, and it imposes a constant output requirement that could unnecessarily limit generation output during high demand, premium periods.

Q. Please summarize your recommendations for the Commission.

A. I recommend that the Commission do the following:

1. Reject Duke Energy's current proposed material modification language in the terms and conditions.

2. Require that Duke Energy honor existing contracts with QFs that integrate battery storage, for all capacity in their contract.

---

[23] Duke Energy Initial Statement at p. 24.

OFFICIAL COPY

Jul 29 2019

3. Require that Duke Energy develop a modified rate design proposal for existing QFs that seek to integrate battery storage, to be approved by the Commission, that will: (1) pay QFs their existing rates; (2) shift the premium pricing time periods to align with current system peaks.

4. Require that Duke Energy allow QFs that integrate battery storage to shift the profile of generation and discharge at the discretion of the operator, so long as the QFs dispatch in accordance with the final Commission-approved Energy Storage Protocol and during a time period that the Companies have evaluated with a System Impact Study.

5. Require that Duke Energy amend the Energy Storage Protocol to (1) only regulate output of the QF, not operation of the subcomponents; and (2) remove the requirement of constant output during the premium peak hours.

6. Require that Duke Energy expedite System Impact Studies for existing QFs that want to integrate battery storage to understand the grid impacts from the integration of a solar QF in all hours when the utility thinks there could be a system peak (not just during the hours that fall within current study window).

7. Require that Dominion Energy follow all the above outlined recommendations if any QFs in Dominion Energy's territory seek to integrate battery storage into an existing QF.

Q. Does this conclude your testimony?

A. Yes

OFFICIAL COPY

Jul 29 2019

BY MS. BOWEN:

Q And Ms. Glick, did you prepare a summary of your testimony?

A I did, yes.

Q And would you please give your summary to the Commission?

A Yes. Madam Chair and members of the Commission, my name is Devi Glick. I am a Senior Associate at Synapse Energy Economics. Synapse is a research and consulting firm specializing in electricity and natural gas industry regulation, planning, and analysis, located at 485 Massachusetts Avenue in Cambridge, Massachusetts. I hold a bachelor's degree in environmental studies from Middlebury College and master's degrees in environmental science and public policy from the University of Michigan, and I have over six years of professional experience as a consultant, researcher, and analyst.

At Synapse, and previously at Rocky Mountain Institute, I focused on a wide range of energy and electricity issues, including utility resource planning, distributed energy resource valuation, energy efficiency program impact analysis, and rate design effectiveness. On topics related to the costs and benefits of

OFFICIAL COPY

Jul 29 2019

distributed generation I've submitted written testimony and appeared in person before the Public Service Commission of South Carolina in a number of dockets relating to the avoided cost associated with solar photovoltaics. Additionally, I have co-authored two studies reviewing valuation methodologies for solar photovoltaics.

I appreciate the opportunity to participate in these important proceedings. I'm here to testify on behalf of the Southern Alliance for Clean Energy. In my testimony I respond to the supplemental testimony filed by Duke Energy Carolinas, Duke Energy Progress, and Dominion Energy North Carolina regarding the Terms and Conditions that should apply to existing qualifying facilities that seek to integrate battery storage. Specifically, I respond to Duke Energy's proposal that any QF, qualifying facility, attempting to integrate battery storage should be required to forfeit its Power Purchase Agreement and operate in accordance with the Company's proposed storage protocols.

In my testimony I discuss how Duke Energy's proposed language granting the Companies the sole discretion to deny requests by existing QFs to add battery storage while retaining preexisting standard

OFFICIAL COPY

Jul 29 2019

offer Power Purchase Agreements is bad policy that harms ratepayers. Duke Energy's proposal actively discourages the addition of battery storage, a resource that firms solar PV capacity, allows QFs to shift production to align with system peaks, and lower systems' cost by deferring or eliminating need to build new peaking capacity resources. Furthermore, Duke Energy's witnesses claim, without justification, that existing QFs seeking to add battery storage while retaining their preexisting PPAs would be inequitable and inconsistent with PURPA, while ignoring the opportunity that battery storage creates to alter QF energy output and shift power production toward the hours when the system has the highest needs.

I respectfully urge the Commission to reject Duke Energy's proposal regarding the Terms and Conditions applicable to existing QFs seeking to add storage. I recommend the Commission adopt an order that encourages the addition of battery storage, an important capacity resource that can benefit the grid and ratepayers. I recommend that the Commission reject Duke Energy's proposed material modification language in the Terms and Conditions, require that Duke Energy honor existing contracts with QFs that integrate battery storage for all

OFFICIAL COPY

Jul 29 2019

capacity in their contract, and develop a rate design -- a modified rate design proposal for existing QFs that seek to integrate battery storage, to be approved by the Commission, that will pay QFs their existing rates and shift premium time periods to align with current system peaks. Thank you.

Q Thank you, Ms. Glick.

MS. BOWEN: Madam Chair, Ms. Glick is available for cross examination.

CHAIR MITCHELL: Thank you. At this point we're going to take a break. We'll return at 3:45. Thank you. Let's go off the record.

(Recess taken from 3:27 p.m. to 3:47 p.m.)

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

MS. BOWEN: Madam Chair, just -- as I said just before the break, Ms. Glick is now available for cross examination.

CHAIR MITCHELL: Mr. Dodge, do you have questions for Ms. Glick?

MR. DODGE: We do not.

CHAIR MITCHELL: Okay.

CROSS EXAMINATION BY MS. FENTRESS:

Q Good afternoon, Ms. Glick. My name is Kendrick

OFFICIAL COPY

Jul 29 2019

Fentress. I'm an attorney with Duke Energy. How are you this afternoon?

A I'm good. How are you?

Q I'm -- I'm great. Thank you. You indicate in your testimony on page 2 of your -- of your responsive testimony that the primary purpose of your testimony was to respond to Duke Energy's joint supplemental testimony which was filed on July 3rd; is that correct?

A Yes. That's correct.

Q And turning to your testimony on page 3, you first take issue with Duke Energy's proposed language on material modification; is that correct?

A The language in the -- in the PPA -- in the -- that -- that is -- I'm just talking about what was addressed in the specific supplemental testimony that was filed. I understand that there is a difference between material modifications and material alterations that I might have confused, and I hope that doesn't become the main topic of this whole conversation right now.

Q It -- it is, actually, the main topic --

A Okay.

Q -- of this conversation. In Footnote 6 and -- Footnotes 6 and 7 you mention the proposed language in your testimony that you're contesting was filed in the

OFFICIAL COPY

Jul 29 2019

Joint Initial Statement; is that correct?

A If that's what it says, that's correct.

Q Yes. And that Joint Initial Statement was filed November 1st, 2018; is that correct?

A Yes.

Q And am I correct, then, that your prefiled testimony does not address or cite to the changes that Duke made to its proposed language in response to concerns from the Public Staff and NCSEA in its reply comments filed March 27th?

A Can you repeat that?

Q Sure. Your prefiled testimony does not address the changes that Duke Energy made to its -- you say material modification language; it's now material alteration language -- in -- in its reply comments. In other words, you have not cited any language from Duke in your -- in Duke's -- from Duke's reply comments in your prefiled testimony; is that correct?

A If that's -- if there's nothing cited, that's correct. My -- my testimony is responding to the supplemental testimony, and insofar as that supplemental testimony is addressing issues from that -- that -- the testimony, then it does address it, but if it does not directly cite it, then, no, it doesn't directly cite it.

OFFICIAL COPY

Jul 29 2019

Q And you haven't specifically cited the changes to Duke's testimony -- I mean, I'm sorry -- to Duke's material modification language in your testimony anywhere, have you, your prefiled testimony?

A If there's no citations, I take your word for it that I did not cite it.

MS. FENTRESS: That's all I have.

CROSS EXAMINATION BY MR. DANTONIO:

Q Hi, Ms. Glick. I'm Nick Dantonio representing Dominion. Hope you're doing well.

A (Nods affirmatively.)

Q All right. You have your supplemental testimony there in front of you, correct?

A I do, yes.

Q Okay. I just have a couple of clarifications, and this could take almost no time at all. So as Ms. Fentress just pointed out, on page 2 towards the bottom of your testimony you talk about how the primary purpose of this testimony is to respond to Duke's supplemental testimony, correct?

A That's correct.

Q But then there's the sentence that is at the end of page 2 and continues on to page 3 where you say that you were not looking to respond to Dominion

OFFICIAL COPY

Jul 29 2019

specifically, but you do add the little footnote there that says Dominion's positions in its supplemental testimony are pretty similar to Duke's, correct?

A Yeah. That's correct. It's hard to respond to something that's not specifically proposed.

Q Right. And did you have a chance to review the supplemental -- I know the way this worked out procedurally you didn't have a chance to respond again, but did you have a chance to review Dominion's supplemental rebuttal testimony?

A Yeah. I believe I looked at it quickly.

Q Okay. So if we'll turn to the very end of your testimony now --

A All right.

Q -- page 14, starting at line 18 you list out different recommendations, and that continues on to the next page, page 15. And those first six recommendations are specific to Duke, right?

A That's correct.

Q And then the reason we're talking today is for recommendation 7 is just all of the above should apply to Dominion as well. Is that a fair characterization?

A It's -- I believe so. I mean, insofar as something is referred as specific provisions of Duke, no,

OFFICIAL COPY
Jul 29 2019

but in the -- the spirit of it, yes.

Q That's perfect. Okay. That will save us all the time instead of going through all six of these. So that was going to be my now last question, is you're willing to caveat that statement a bit to say that only to the extent that some of these recommendations would logically apply to Dominion?

A Well, yes. Like I don't expect Duke's -- I don't expect Dominion to make changes to Duke's system impact studies. The -- the point of bullet point 7 is that if there are changes that can be made to allow battery storage to be integrated that benefits both ratepayers and benefits the QFs, there is no reason why the Utility should not be open to negotiating that, and the Commission should require that the Utilities do that because it will benefit ratepayers. And without the Commission requiring that, that's leaving value on the table for ratepayers.

Q Okay. Great. But to the extent like Condition or Recommendation 1, talking about material modification language that Dominion did not propose in this proceeding or the language about the battery storage protocols that Dominion did not propose, we're okay to state for the record that Recommendation 7 would not relate back to

OFFICIAL COPY

Jul 29 2019

those types of recommendations, right?

A Yeah. So when I -- I'll clarify. When I say require that Dominion follow the above outlined recommendations, to the extent that Dominion proposes an energy storage protocol, for example, in the future, my recommendation is in -- my recommendation would be that they follow what I've outlined here for the energy storage protocol. So to the extent that certain things are not currently developed or proposed by Dominion, when they are developed, when they are proposed, my recommendations that I laid out for Duke should be applied to Dominion.

Q Perfect. All right.

MR. DANTONIO: No further questions from me. Thank you.

MS. BOWEN: I don't think I have any redirect. Thank you.

CHAIR MITCHELL: Okay. Questions from the Commission?

EXAMINATION BY CHAIR MITCHELL:

Q Ms. Glick, I do have a question for you. You provide testimony on value provided by QFs, and specifically you -- you testify that a solar QF paired with energy storage can increase the value provided by

OFFICIAL COPY

Jul 29 2019

the QF. Just talk for a minute about specifically what you mean by that statement.

A Yeah. So when you add --

Q And -- and hang on one second. Let me finish my question. Explain what you mean by increase value, and then also respond to the indifference principle that Mr. -- that Duke witnesses and specifically Duke Witness Snider has -- has testified to in this proceeding, to the extent that you're in a position to do.

A So I'm happy to answer your first question. I haven't been here for the previous days, so you'll probably have to give me a little more information about the principle that you're referring to for the second part of your question.

For the first part of your question, the value that -- the additional value that --

MS. BOWEN: Ms. Glick, sorry. Just one second. Madam Chair, if it's helpful, yeah, Ms. Glick had a date certain of today and tomorrow, but if you would like me to clarify, I can do it at the question responding to Commission questions, I'm happy to clarify for Ms. Glick I think what I understand you're referring to.

CHAIR MITCHELL: Okay. Let's handle it that way. Thank you.

OFFICIAL COPY

Jul 29 2019

MS. BOWEN: For the second part, yeah.

CHAIR MITCHELL: Okay.

A So the first part of your question, which I believe you said what is the additional value that is provided by the solar -- the QF when you add battery storage to it, so I understand that in the existing -- in the existing PURPA rate there is avoided energy, avoided capacity, and so the -- the claim is that there's already energy and capacity value being provided in the current rate. So when you add battery storage to the existing QF, you add additional capacity.

And so the -- the capacity that's being provided firms up the solar, so it means that -- and it can control ramping, it can control -- provide ancillary services, so frequency regulation, voltage regulation. It can provide deferred transmission capacity and distribution capacity. It can provide deferred environmental benefits that are not currently captured, for example, coal ash disposal. You're no longer disposing and having to build and take care of coal ash that's down the road when ratepayers are having to pay for new pits that are lined and properly taken care of.

So all of those things are provided when you provide the capacity from battery storage with solar

OFFICIAL COPY

Jul 29 2019

because you don't have to build new peaking plants. You don't have to run the existing fossil-fired generation plants as much. You don't have to run the existing generation plants to provide the ancillary services. You don't have to build new transmission networks that you were providing just to meet additional load because the transmission network is built out when you have to move generation from the central plants to the load centers. When you have more generation coming out of the distributed areas, the load centers, you don't have to move it over that same area, especially at peak hours.

The impacts in the distribution network can be a little bit trickier, and generally you'd need to do, you know, feeder level studies to figure out exactly the distribution system impact, so those are distinct from the transmission system impacts.

But all of those values are not captured under the current avoided cost energy and capacity values under PURPA.

CHAIR MITCHELL: Thank you. Any additional questions from the Commission? Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yeah. A follow up on the Chairman's question, though.

EXAMINATION BY COMMISSIONER CLODFELTER:

OFFICIAL COPY

Jul 29 2019

Q Would you agree, though, that the ability to realize some of those values that you listed in your articulation depends on how the storage is managed and perhaps indirectly, therefore, who controls management of the storage?

A So with ancillary services, that's definitely a concern. With some of the others, though, with, for example, capacity value, that's not the case. If you set the -- the rate correctly, if you set the peak periods to align with when the system actually needs that capacity, the QFs will act economically rationally and dispatch the electricity during those hours, so you do not need the Utility to be controlling the battery to get the firm capacity from the battery storage. The QF is going to act economically rationally and dispatch if it has the right rates and the right time period windows, which is why my recommendation is to realign the time period windows.

Q But some of the values do depend upon how it's managed and who controls it --

A Some of the --

Q -- correct?

A -- ancillary services can -- can depend on that.

OFFICIAL COPY

Jul 29 2019

CHAIR MITCHELL: Questions on Commission questions?

MS. BOWEN: So I can attempt to -- to clarify for Ms. Glick the second part of your question, Chair Mitchell, which is Glen Snider, a witness for Duke Energy in these proceedings, has testified to the fact that if you're talking about the value that adding storage to a solar facility, for example, provides, that under the PURPA framework you're really talking about costs that are being avoided, so the ratepayer is sort of indifferent as to whether that's, you know, power being provided by a QF or power being provided by the Utility, at least in terms of the values that are captured sort of under the PURPA framework as it's currently implemented in North Carolina. And so I -- I think, and the Chair -- Chair Mitchell can correct me if I'm wrong on this, but I think she is looking just for your response or input on -- on, you know, I guess do you agree with that or do think there are values that are not being captured or -- or anything else to -- to comment on in terms of keeping the ratepayer indifferent on the -- the cost of the values of adding storage.

Do I have that right, Chair Mitchell? Did I explain that okay?

OFFICIAL COPY

Jul 29 2019

CHAIR MITCHELL: Yes.

MS. BOWEN: Okay.

A Yeah. So, I mean, yes, I agree that the -- the point of PURPA is to make the ratepayers indifferent. I would say that right now if you are forcing a -- if you're telling a qualifying facility that the only way they can add battery storage is if they go onto a new rate, and there is so many different permutations on how the rates would -- how the QFs would have to be compensated based on when they signed the contract, so it's not clear. I think as -- as Witness Norris said, exactly how it might pencil out for the QFs, whether they would really add battery storage if they had to forfeit their contract and go onto a new one. That battery storage is actively increasing the value to the ratepayer.

So that's not -- it's not a matter of keeping the ratepayers indifferent. That battery storage actually will increase the value to the ratepayers and increase the value to the QFs, so it's a -- it's a total net positive for both parties, and that value is being left on the table.

So I -- I agree that the -- I -- I'm not disagreeing that the -- the role of PURPA is to make the

OFFICIAL COPY

Jul 29 2019

-- is -- the ratepayer should be indifferent between purchasing from the Utility or from the QF, but right now there is value being left on the table that can add more value to the ratepayers for the -- for the service being provided by the QFs. So the QFs are currently operating the hours that solar is available, and when you add battery storage, that -- that can offset the need to install new capacity and to pay for other services that are not captured under PURPA.

CHAIR MITCHELL: Thank you. Any additional questions on the Commission's questions?

(No response.)

CHAIR MITCHELL: Okay. Ms. Glick, appreciate your coming. You may step down. Thank you.

MR. DODGE: Chair Mitchell, the Public Staff calls the Panel Bob Hinton, Dustin Metz, and Jeff Thomas forward. If we could have just a moment to arrange the room for the Panel.

CHAIR MITCHELL: Good afternoon, gentlemen. Let's get you sworn in.

JEFF T. THOMAS, DUSTIN R. METZ, JOHN R. HINTON;

Having been duly sworn,

Testified as follows:

MR. DODGE: Thank you. While Ms. Cummings is

OFFICIAL COPY

Jul 29 2019

distributing copies of the summary, we can go ahead and get started with Mr. Hinton.

DIRECT EXAMINATION BY MR. DODGE:

Q Mr. Hinton, could you please state your name and address for the record.

A (Hinton) My name is John Robert Hinton.

COMMISSIONER GRAY: I'm sorry. You'll have to speak into the mic.

A (Hinton) My name is John Robert Hinton. I work at 430 North Salisbury Street, and I'm Director of Economic Research Division for the Public Staff.

Q Mr. Hinton, did you cause to be prefiled on June 21st, 2019 in this docket testimony consisting of 18 pages and an appendix?

A Yes.

Q Do you have any changes or corrections to your testimony at this time?

A Yes, I do.

Q Would you please share that correction?

A On page 17 of my testimony, the two changes are on lines 7 and 8. On line 7 I want to add the word the capacity and a comma after the word increase. On line 8 I just want to add a comma after the number 5 percent. That's all.

OFFICIAL COPY

Jul 29 2019

Q Other than that change, if I asked you the same questions today, would your answers be the same?

A Yes, they would.

Q Thank you.

MR. DODGE: Madam Chair, at this time I move that the prefiled testimony of Bob Hinton be entered into record as if given orally from the stand.

CHAIR MITCHELL: Hearing no objection, the motion is allowed.

(Whereupon, the prefiled testimony of John R. Hinton, as corrected, was copied into the record as if given orally from the stand.)

OFFICIAL COPY

Jul 29 2019

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of		
Biennial Determination of Avoided Cost	)	TESTIMONY OF
Rates for Electric Utility Purchases from	)	JOHN R. HINTON
Qualifying Facilities – 2018	)	PUBLIC STAFF – NORTH
	)	CAROLINA UTILITIES
	)	COMMISSION

OFFICIAL COPY

Jul 29 2019

Q. PLEASE STATE FOR THE RECORD YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is John R. Hinton. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Director of the Economic Research Division of the Public Staff - North Carolina Utilities Commission. My qualifications are included in Appendix A to this testimony.

Q. WHAT ARE YOUR DUTIES AT THE PUBLIC STAFF?

A. My duties with the Public Staff are to review the funding involved for nuclear decommissioning plans, weather normalization of energy sales, electric utility meter sampling plans, the electric utilities' long-range peak demand and energy forecasts, and the integration aspect of the electric utilities' Integrated resource plans (IRPs). I also review electric utilities' avoided cost biennial filings, as well as avoided cost issues for fuel cases and annual rider proceedings involving renewable energy and demand-side management and energy efficiency (DSM/EE). I also conduct financial studies on the investor-required rate of return for water, natural gas, and electric utilities.

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

306

OFFICIAL COPY

Jul 29 2019

A. The purpose of my testimony is to present the Public Staff's position on proposed modifications to the avoided cost rates of Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC) (collectively, "Duke"), pursuant to the Commission's April 24, 2019, *Order Scheduling Evidentiary Hearing and Establishing Procedural Schedule*. My testimony should be considered in conjunction with that of Public Staff witness Jeff Thomas. Specifically, I will address the following issues identified by the Commission that merit consideration in an evidentiary hearing:

(i) Duke's IRP assumptions regarding expiring wholesale contracts;

(ii) The recommendation of the North Carolina Sustainable Energy Association (NCSEA) to calculate avoided capacity rates based upon a hypothetical December 31, 2021, in-service date for Standard Offer Qualifying Facilities (QFs); and

(iii) Duke's proposed modifications to the Standard Offer Terms and Conditions.

<u>Duke's IRP assumptions regarding expiring wholesale contracts</u>

Q. BRIEFLY DESCRIBE DUKE'S ASSUMPTIONS WITH REGARD TO EXPIRING WHOLESALE CONTRACTS.

307

OFFICIAL COPY

Jul 29 2019

A. As described in Duke witness Glen A. Snider's direct testimony in this docket, Duke's IRPs include for planning purposes the capacity and energy from all wholesale purchase power contracts, including QF and non-QF purchases, for the duration of the contract term.[1] However, Duke does not assume that those contracts continue to provide energy and capacity beyond the expiration of the contract term.[2] Duke indicated that the utilities' IRPs should therefore indicate a reduction in capacity in the year following the contract expiration, which may be met by undesignated resources, including QF contracts (new facilities or renewals), wholesale purchases, or potentially new utility-owned generation.

Based on this assumption, one would expect Duke's IRPs to indicate reductions in capacity from QFs over time. Duke's 2018 IRPs did indicate a reduction in capacity for biomass and hydroelectric generators over the planning period as contracts expire; however, the IRPs indicated an increase in capacity from solar facilities over the planning period. This issue, as discussed in the initial comments of the Small Hydro Group and NCSEA in this proceeding, impacts

---

[1] Direct testimony of Duke witness Glen A. Snider at 5. Docket No. E-100, Sub 158 (May 21, 2019).

[2] As a point of reference, the Public Staff also reviewed the IRP assumptions made by Dominion Energy North Carolina (DENC) with regard to its purchase power contracts with non-utility generating units, and notes that DENC similarly assumes for IRP planning purposes that the contracts do not provide energy and capacity beyond the expiration of the contract term.

OFFICIAL COPY

Jul 29 2019

the first year in which the utilities indicate a capacity need in their IRPs. Pursuant to N.C. Gen. Stat. § 62-156(b)(3), a capacity need in their IRP provides the basis for determining when a capacity payment shall be made to a QF. In response to data requests submitted by the Public Staff and other parties, Duke indicated that for planning purposes, it also assumes that purchase power agreements (PPAs) are expected to be either renewed or replaced in kind.[3] The assumptions as to renewal of wholesale power contracts as opposed to solar PPAs appear to be in conflict and indicate potentially different treatment of QF contracts.

Q. WHY IS THIS ASSUMPTION IN DUKE'S CURRENT IRPs NOT APPROPRIATE FOR DETERMINING THE FIRST YEAR IN WHICH A QF SHOULD BE ENTITLED TO A CAPACITY PAYMENT?

A. While Duke's 2018 IRPs assume that contracts for wholesale generation and QF generation will not be renewed, its IRPs assume that solar generation will be replaced with similar or in-kind generation from other QFs.[4] This may be a reasonable assumption

[3] In response to Public Staff Data Request No. 6-4 in Docket No. E-100, Sub 157, DEC and DEP stated that "[i]n general, compliance and non-compliance qualifying facilities are expected to expire when the purchase power agreement terminates. For planning purposes, QF PPAs are expected to be either renewed or replaced in kind. Importantly, however, there is no explicit or implicit assumption in the IRP of contract renewals with any given existing QF facility owner."
[4] DEC's and DEP's Reply Comments, Docket No. E-100, Sub 158, at 45. (March 27, 2019).

OFFICIAL COPY

Jul 29 2019

for long-term planning purposes, but it is inappropriate for determining the first year in which a QF is entitled a capacity payment. The use of this assumption can lead to situations where the need for additional capacity is pushed out one or more years into the future and could cause certain QFs not to receive a payment for their contribution to the Company's need for capacity.

Q. PLEASE CLARIFY WHEN A CAPACITY NEED WARRANTS A CAPACITY PAYMENT.

A. Pursuant to N.C. Gen. Stat. § 62-156(b)(3), capacity payments should be made when there is a stated need of additional capacity as determined by the IRP. However, as discussed in our initial comments in the 2018 IRP proceeding, the Public Staff does not consider modifications to existing facilities that result in a capacity increase, such as plant uprates, to be a deferrable capacity need.[5] The Public Staff maintains that the utility is expected to continue to make plant uprates where reasonable and prudent, which help improve reliability and dependability and decrease system operating costs. A capacity expansion plan designates when a new generation unit is needed and is often the result of load growth, unit

[5] Initial Comments of the Public Staff, Docket No. E-100, Sub 157, at 90-91. (March 7, 2019).

OFFICIAL COPY

Jul 29 2019

retirements, or, as is the case in DEP's 2018 IRP, the expiration of wholesale power purchase contracts.

Q. HOW DOES THE PUBLIC STAFF PROPOSE TO ADDRESS THESE CONCERNS REGARDING THE ASSUMPTIONS MADE WITH REGARD TO EXPIRING WHOLESALE CONTRACTS?

A. In our initial comments in the 2018 IRP proceeding and in our reply comments in this docket, the Public Staff recommended the inclusion of a statement specifying the assumptions used in the determination of a utility's first year of capacity need, including whether existing QF contracts are assumed to have been renewed, replaced in kind, or terminated.[6] As described in witness Snider's testimony, Duke recognized this lack of clarity in the timing of new capacity additions and deficits, specifically including the treatment of QF projects, and agreed to our recommendation to more clearly address this issue in future IRPs within a new Statement of Need section.[7]

Q. HAS THE PUBLIC STAFF FURTHER INVESTIGATED THIS ISSUE WITH DEC AND DEP?

---

[6] *See* Initial Comments of the Public Staff, at 89, in Docket No. E-100, Sub, 157 (March 7, 2019); Reply Comments of the Public Staff at 12-14, in Docket No. E-100, Sub 158 (March 27, 2019).

[7] Direct testimony of Glen A. Snider at 14.

A. Yes. Since the filing of our reply comments in this proceeding, the Public Staff has engaged in further conversations with DEC and DEP regarding this topic. As a result of these discussions, the Public Staff understands that in order to establish the first year of needed capacity for avoided cost purposes, DEC and DEP utilize a parallel IRP expansion plan that does not include the Company's assumption regarding the replacement of in-kind solar QF generation. This use of two different expansion plans is somewhat similar to the approach taken by DEC and DEP with regard to the treatment of future carbon dioxide (CO_2) cost assumptions. In the 2014 avoided cost proceeding, DEC and DEP discussed the distinction between the development of a long-term resource expansion plan that is robust and accounts for the possibility of future carbon costs, with the intent of the Public Utility Regulatory Policies Act of 1978 (PURPA), which is to calculate avoided costs based on currently known and verifiable costs.[8] In its December 31, 2014, *Order on Inputs*, the Commission held that for the purpose of calculating avoided energy rates, the generation expansion plans used in the avoided production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs, and that CO_2 costs were "not sufficiently certain to be included in avoided costs at this time."[9]

[8] *Order Setting Avoided Cost Input Parameters*, at 44, Docket No. E-100, Sub 140 (December 31, 2014).
[9] *Id.*

311
OFFICIAL COPY
Jul 29 2019

OFFICIAL COPY

Jul 29 2019

Duke does not know with reasonable certainty whether a QF will renew its contract, so the utilization of an IRP expansion plan that does not include this assumption regarding the renewal of existing QF contracts is reasonable to ensure that new and renewing QFs will have an opportunity to receive a capacity payment when the first need is specified in the IRP.

Q. UNDER EITHER APPROACH USED BY DUKE, WOULD THE FIRST YEAR OF CAPACITY NEED HAVE BEEN IMPACTED IN THE CURRENT PROCEEDING?

A. No. It is my understanding based on conversations with Duke that the first year of capacity need indicated in DEC's and DEP's 2018 IRPs would not change, regardless of the assumptions made about wholesale contract renewals.

Q. DOES THE PUBLIC STAFF ACCEPT DUKE'S ASSUMPTIONS WITH REGARD TO EXPIRING WHOLESALE CONTRACTS?

A. Yes. Based on these further conversations with Duke indicating that the year of capacity need would be unchanged in this case regardless of the assumption used for contract renewals, and Duke's agreement to include a statement of need in future IRPs for the purposes of establishing the first year of needed capacity for avoided cost purposes, the Public Staff believes this approach is reasonable.

OFFICIAL COPY

Jul 29 2019

Because the IRP is utilized in various regulatory proceedings,[10] the Public Staff believes that a definitive statement of need, subject to approval by the Commission, would remove uncertainty surrounding the exact year of capacity need and provide a clearer standard for all parties to these various regulatory proceedings.

Q. DO YOU AGREE WITH THE SMALL HYDRO GROUP AND NCSEA'S RECOMMENDATION THAT THE UTILITIES ASSUME ALL QF CONTRACTS RENEW, AND SHOULD THEREFORE BE ENTITLED TO A CAPACITY PAYMENT IN THE FIRST YEAR OF THEIR RENEWED CONTRACT?

A. No, I do not. This does not appear to comport with the requirement that a "future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to N.C. Gen. Stat. § 62-110.1(c) has identified a projected capacity need to serve system load" called for in N.C. Gen. Stat. § 62-156(b)(3), which applies to any QF seeking to enter into a PPA with the utility, whether new or existing. Under the Small Hydro Group's and NCSEA's position, the utilities would be required

[10] In addition to providing the basis for electric power purchases from QFs by a utility, the avoided costs determined by the Commission are utilized in other applications, including the determination of the cost effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs; the determination of the incremental costs of compliance with the Renewable Energy Portfolio Standard (REPS) for cost recovery purposes; and in some ratemaking processes, such as the determination of stand-by rates.

OFFICIAL COPY

Jul 29 2019

to assume that the capacity and energy from existing QF contracts would be available in perpetuity. While the Public Staff acknowledges that many QFs will likely seek to renew their contracts at the end of the term, some QFs do cease operations or find other alternatives for the use of their energy and capacity. In addition, the recommendation by the Small Hydro Group and NCSEA would advantage existing QFs over new facilities, in that they would be entitled to a capacity payment in the first year following their renewal, whether or not the utility's IRP indicated a capacity need existed at the time of renewal.

<u>NCSEA's Recommendation to Calculate Avoided Capacity Rate Based Upon a Hypothetical December 31, 2021 In-Service Date for Standard Offer QFs</u>

Q. **DOES THE PUBLIC STAFF AGREE WITH NCSEA'S RECOMMENDATION THAT THE EXPECTED IN-SERVICE DATE SHOULD BE EXTENDED TO A FUTURE DATE FOR STANDARD OFFER QF CONTRACTS AND NEGOTIATED CONTRACTS?**

A. The Public Staff recognizes that delays in the interconnection queue may be impacting the timeline for many QF projects to come online, but the Public Staff does not support NCSEA's recommendation for using a later presumptive in-service date for a Standard Contract term. The utilities' biennial filing of their avoided cost rates is

OFFICIAL COPY

Jul 29 2019

designed to provide a predictable and certain point in time from which the avoided rates can be calculated for standard offer contracts, and should be reflective of the utilities' current estimate of the inputs in avoided cost calculations at that time. In addition, the rates provided at that time are designed to provide the QF (whether a new facility or an existing facility seeking to renew) with some certainty as to the rates and terms under which they can commit to sell the output of their facility at that time. The Public Staff agrees with Duke witness Snider that to the extent a QF seeks to time its Legally Enforceable Obligation (LEO) closer to its actual in-service date, it retains that right to delay establishing a LEO, and may also choose to negotiate a PPA instead of pursuing a standard offer rate.[11] Any shifting away of the start of the Standard Offer contract from the year immediately following of the new rate schedule will likely result in a mismatch of payments made to QFs and the utility's expected avoided energy costs and avoided capacity costs. In addition, as noted in Duke witness Snider's testimony, the smaller facilities that are eligible for standard offer contracts may be able to take advantage of the Section 3 Fast Track and Supplemental Review Interconnection processes under the North Carolina Interconnection Procedures (NCIP), which would allow facilities to complete the interconnection

[11] Direct testimony of Glen A. Snider at 17.

OFFICIAL COPY

Jul 29 2019

process in a more timely fashion and be able to be placed in service in less than a year.[12]

Q. DOES THE PUBLIC STAFF HAVE ANY RECOMMENDATIONS REGARDING THE IN-SERVICE DATE FOR STANDARD OFFER QF CONTRACTS AND NEGOTIATED CONTRACTS?

A. As stated in our reply comments in this proceeding, for purposes of establishing the term for a standard offer contract, the Public Staff believes that the Utilities' current practice of assuming an in-service date in the year following the November 1 biennial filing date for avoided costs is a reasonable approach that treats existing facilities and new facilities equitably.[13] However, the Public Staff recommends that the Commission direct the Utilities to clarify the point when an existing QF seeking to renew its PPA can establish a new LEO for both calculating rates and determining when the facility will be eligible to receive a capacity payment. This period of time should be long enough to allow the QF to have sufficient information regarding the rates for which it may be eligible in order to determine whether it would seek to renew. Likewise, the period of time should not be so

---

[12] *Id.* at 16.
[13] Reply Comments of the Public Staff at 29, Docket No. E-100, Sub 158. (March 27, 2019).

OFFICIAL COPY

Jul 29 2019

long that a QF could contract for rates that are misaligned with current avoided costs.

With regard to negotiated contracts, the Public Staff agrees with NCSEA that it may be appropriate for a utility and QF negotiating a PPA to agree to a presumed in-service date for rate calculation purposes that takes into account any extended timelines that may affect the project coming online, such as long lead-time equipment or delays in the interconnection process resulting from interdependencies of projects or system upgrade requirements, which are more likely to be triggered by facilities that are not eligible for the standard offer contracts. Consistent with N.C. Gen. Stat. § 62-156(c) and the Commission's March 6, 2015 *Order on Clarification* in Docket No. E-100, Sub 140, it is appropriate for any party, in the course of bilateral negotiations, to identify specific characteristics of a particular QF that merit consideration in the calculation of negotiated avoided cost rates.

<u>DEC's and DEP's Proposed Modifications to</u>
<u>Their Standard Offer Terms and Conditions</u>

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S POSITION ON DEC AND DEP'S INITIAL PROPOSED MODFICATIONS TO THE STANDARD OFFER TERMS AND CONDITIONS.

OFFICIAL COPY

Jul 29 2019

A. In its November 1, 2018 initial statement, Duke proposed a number of amendments to its standard offer terms and conditions. The Public Staff's February 12, 2019, Initial Comments agreed with some of the changes proposed by Duke, but noted concerns with the following changes to the terms and conditions:

(1) Requiring a QF enter into a new PPA for any facility that increases its annual energy output.[14]

(2) Providing Duke with the right to terminate a PPA for any "material modification to the Facility without the Company's consent or otherwise delivering energy in excess of the estimated annual energy production of the Facility."[15]

(3) Including new provisions related to system operator instructions and energy storage protocol in its standard offer contracts in Section 2.(b) of the Terms and Conditions, but not providing definitions for those terms or providing examples of the forms.[16]

(4) Modifying the Utilities' right to terminate or suspend the agreement based on the facility delivering energy in excess of

[14] Public Staff Initial Comments at 73-77.
[15] *Id.* at 77-81.
[16] *Id.* at 78.

OFFICIAL COPY

Jul 29 2019

the estimated annual energy production of the facility, or for changes in contract capacity.[17]

Q. DID DUKE PROPOSE MODIFICATIONS TO THESE PROPOSED REVISIONS TO ADDRESS THE CONCERNS RAISED BY THE PUBLIC STAFF AND OTHER PARTIES?

A. Yes. Duke addressed a number of these concerns in its March 27, 2019, Reply Comments, and further supported these changes in the testimony of Duke witness David B. Johnson. To address the concerns raised by the Public Staff and NCSEA regarding the utility's right to terminate the PPA or require a QF to enter into a new PPA based on changes to the estimated annual energy production or for making a material modification to the facility, Duke supplemented its definition for "material alteration" to clarify what constitutes a material change that would trigger the utility's right to terminate the PPA if the utility's consent is not first obtained. Duke witness Johnson states that:

> This term clarifies that QF owners may not modify the originally certificated Facility that entered into the PPA and has been selling power at the Companies' pre-existing avoided cost rates in such a way as to increase the Existing Capacity of the generating Facility or to reduce the Existing Capacity by more than 5%. This would include the addition of a Storage Resource, as that term is now defined in the Terms and Conditions.

[17] *Id.* at 80-81.

320

OFFICIAL COPY

Jul 29 2019

> Duke has also clarified that material changes to existing Facilities will be evaluated in a commercially reasonable manner.[18]

In response to concerns raised by NCSEA regarding the uncertainty Duke's proposed changes would create for facilities seeking to repair or replace equipment, Duke also indicated that repairs or replacement of equipment at facilities that do not increase or decrease the capacity of the facility by more than 5% would not be considered a material alteration and could be undertaken without obtaining Duke's prior consent.[19]

In response to the concerns regarding the provisions related to system operator instructions and energy storage protocol in its standard offer contracts in Section 2.(b) of the Terms and Conditions, Duke incorporated a definition of system operator instruction and provided a proposed energy storage protocol specific to QFs contracting to sell power under Schedule PP rates. I note that Public Staff witness Jeff Thomas addresses the Public Staff's position related to Duke's proposed energy storage protocol.[20]

---

[18] Direct testimony of Duke witness David B. Johnson at 8. (May 21, 2019).
[19] *Id.*
[20] The Public Staff also notes the Commission's June 14, 2019, *Order Requiring Supplemental Testimony and allowing Responsive Testimony*, in which the Commission directed the utilities to file supplemental testimony addressing what impact, if any, a "material modification" in the context of the North Carolina Interconnection Procedures, as recently revised in the Commission's June 14, 2019, *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony*, has on contested issues in this proceeding, including the appropriate avoided cost rate schedule and contract terms.

OFFICIAL COPY

Jul 29 2019

Q. DOES THE PUBLIC STAFF SUPPORT DUKE'S PROPOSED MODIFICATIONS TO THE TERMS AND CONDITIONS WITH STANDARD CONTRACTS?

A. In general, yes. While I am not an attorney, the changes made by Duke appear to be responsive to the issues raised by the Public Staff and other intervenors. However, as with the utility plant uprates that may result in an increase in nameplate capacity, a degree of reasonableness is appropriate regarding equipment repairs and replacements made by QFs that may impact the capacity of the facilities, so long as the investments do not materially change the output profile of the QF. The Public Staff agrees with NCSEA in that the tariff language should not have the effect of discouraging efficient investments by QFs, but also recognize that material alterations that that are made without reconsideration of the facility's interconnection study, and the avoided cost rates that are applicable to the QF, would be inappropriate.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

---

and conditions that should apply when a QF adds battery storage to an electric generating facility at various stages of project development.

OFFICIAL COPY

Jul 29 2019

QUALIFICATIONS AND EXPERIENCE

JOHN ROBERT HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. Since joining the Public Staff in May of 1985,I have filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989, and 1992, I developed the long range forecasts of peak demand for electricity in North Carolina. I filed testimony on electricity weather normalization in Docket Nos. E-7, Sub 620, E-2, Sub 833, and E-7, Sub 989. I filed testimony on customer growth and the level of funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023 and the level of funding for nuclear decommissioning costs in Docket No. E-7, Sub 1026. I have reviewed numerous peak demand and energy sales forecasts and the resource expansion plans filed in electric utilities' annual Integrated Resource Plans (IRPs). I have filed testimony on the IRPs filed in Docket No. E-100, Subs 114 and 125.

I have been the lead analyst for the Public Staff in numerous avoided cost proceedings. I have filed testimony on the avoided cost of electricity in Docket No. E-100, Subs 106, 136, 140; 148, and I have filed a Statement of Position in the arbitration case involving EPCOR and Progress Energy Carolinas in Docket No. E-2, Sub 966.

OFFICIAL COPY

Jul 29 2019

I have filed testimony on the issuance of certificates of public convenience and necessity (CPCN) in Docket Nos. E-2, Sub 669, SP-132, Sub 0, E-7, Sub 790, and E-7, Sub 791.

I have filed testimony on the issue of fair rate of return in Docket Nos. E-22, Sub 333; E-22, Sub 412; P-26, Sub 93; P-12, Sub 89; G-21, Sub 293; P-31, Sub 125; G-5, Sub 327; G-5, Sub 386; G-9, Sub 351; P-100, Sub 133b; P-100, Sub 133d (1997 and 2002); G-21, Sub 442; W-778, Sub 31; and W-218, Sub 319, E-22, Sub 532, and W-218, Sub 497, W-354, Sub 360. I have filed testimony on credit metrics and the risk of a downgrade in Docket No. E-7, Sub 1146. I have filed Affidavits on the appropriate overall cost of capital and margin on expenses for numerous small water and sewer utilities.

With regard to the 1996 Safe Drinking Water Act, I was a member of the Small Systems Working Group that reported to the National Drinking Water Advisory Council of the U.S. Environmental Protection Agency (EPA). I have published an article in the National Regulatory Research Institute's (NRRI's) Quarterly Bulletin entitled Evaluating Water Utility Financial Capacity.

OFFICIAL COPY

Jul 29 2019

BY MR. DODGE:

Q Mr. Hinton, do you have a -- did you prepare a summary of your testimony?

A Yes, I did.

Q Would you please provide it at this time?

A Yes. The purpose of my testimony is to comment and make recommendations to the Commission on the assumptions regarding expiring wholesale contracts in the Integrated Resource Plans by Duke Energy Carolinas and Duke Energy Progress, collectively Duke, and the first year that a need for additional generation is identified for the purposes of establishing -- establishing a capacity need for -- such that qualifying facilities are entitled to -- to avoided capacity payments. The Public Staff initially expressed concerns in this proceeding and in the 2018 IRP proceeding in Docket E-100, Sub 158, with the assumptions made by Duke that expiring Purchase Power Agreements with solar QFs would be renewed or replaced in-kind, while non-solar QF PPAs were assumed to expire without renewal. As a result of these discussions, Duke clarified that for purposes of avoided costs, it assumes that all QF PPAs do not renew after expiration, which is comparable to Duke's assumptions for other wholesale purchase contracts. This approach also ensures that

OFFICIAL COPY

Jul 29 2019

existing QFs are treated comparably -- comparably with new QFs seeking to sell their output to the Utilities. Duke has also agreed to include a Statement of Need in future IRPs to clearly identify the first need (sic) of needed capacity for avoided cost purposes.

My testimony also addresses the recommendation by the North Carolina Sustainable Energy Association to calculate avoided capacity rates based on a hypothetical in-service date of December 31st, 2021 for standard offer QFs. I indicate that the use of a latter in-service date, rather than in the year immediately following the biennial filing of avoided cost rates, would create a greater mismatch of payments made to QFs in relation to their expected avoided costs. My testimony generally supports the proposed revisions to Duke's standard offer Terms and Conditions.

This concludes my summary.

Q Thank you.

MR. DODGE: Moving to Mr. Metz.

Q Mr. Metz, would you please state your name and address for the record?

A (Metz) My name is Dustin Ray Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

OFFICIAL COPY

Jul 29 2019

Q By whom are you employed and in what capacity?

A I'm employed with Public Staff. I'm a Utilities Engineer.

Q Did you cause to be prefiled on July 3rd in this docket responsive testimony consisting of 20 pages and an appendix?

A Yes, I did.

Q Do you have any changes or corrections to your testimony at this time?

A Yes, I do.

Q Will you please share that with the Commission?

A On page 11 of my testimony, on line 4, the word modification should be replaced with alteration. That is it.

Q Other than that change, if I asked you the same questions today, would your answers be the same?

A Yes, they would.

Q Thank you.

MR. DODGE: Madam Chair, at this time I move that the prefiled testimony of Dustin Metz be entered into the record as if given orally from the stand.

CHAIR MITCHELL: Motion is allowed.

(Whereupon, the prefiled supplemental testimony of Dustin R. Metz, as corrected, was copied into the record as if given orally from the stand.)

OFFICIAL COPY

Jul 29 2019

OFFICIAL COPY

Jul 29 2019

Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff, representing the using and consuming public.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are outlined in detail in Appendix A of my testimony.

Q. MR. METZ, HAVE YOU FILED TESTIMONY PREVIOUSLY IN THIS DOCKET?

A. No, I have not. However, I filed testimony in the 2016 biennial avoided cost proceeding in Docket No. E-100, Sub 148 (Sub 148 Proceeding) and have worked extensively with other Public Staff members in both this avoided cost proceeding and the most recently proposed revisions to the North Carolina Interconnection Procedures (NCIP) in Docket No. E-100, Sub 101. I have also participated in multiple informal disputes and settlements surrounding interconnection and other technical matters.

OFFICIAL COPY
JUL 03 2019

OFFICIAL COPY
JUL 29 2019

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

A. The purpose of my testimony is to address the specific issues detailed by the North Carolina Utilities Commission (Commission) in its June 14, 2019 *Order Requiring Supplemental Testimony and Allowing Responsive Testimony.*[1]

Q. IS THERE SIGNIFICANT BATTERY STORAGE INSTALLED AND OPERATING IN NORTH CAROLINA AT THIS TIME?

A. No. While North Carolina is ranked second in the United States in total solar energy capacity,[2] there is currently only a small amount of battery storage capacity deployed in the State.[3]

Q. DOES BATTERY STORAGE HAVE THE POTENTIAL TO BE AN IMPORTANT RESOURCE WHEN PAIRED WITH INTERMITTENT RESOURCES SUCH AS SOLAR?

---

[1] The Commission requested testimony addressing the following question: "what avoided cost rate schedule and contract terms and conditions apply when a Qualifying Facility adds battery storage to an electric generating facility that has (i) established a legally enforceable obligation (LEO), (ii) executed a power purchase agreement (PPA) with the relevant utility, and/or (iii) commenced operation and sale of the electric output of the facility to the relevant utility pursuant to an established LEO and executed PPA." This order was issued contemporaneously with the June 14, 2019 *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony* issued in Docket No. E-100, Sub 101, (Sub 101 Order) in which the issue of what constitutes a "material modification" was addressed.

[2] Solar Energy Industries Association, North Carolina Solar Fact Sheet, Online at: https://www.seia.org/state-solar-policy/north-carolina-solar. Date accessed: July 1, 2019.

[3] Energy Storage Options for North Carolina, prepared by the North Carolina State University Energy Storage Team, at 4. Online at: https://energy.ncsu.edu/storage/wp-content/uploads/sites/2/2019/02/NC-Storage-Study-FINAL.pdf. Date accessed: July 1, 2019.

OFFICIAL COPY
JUL 29 2019

A. Yes, if it is operated in a complementary function. One of the primary criticisms of intermittent resources such as solar photovoltaic facilities by Duke Energy Carolinas, LLC , Duke Energy Progress, LLC (jointly, "Duke") and Dominion Energy North Carolina (DENC) (collectively, the "utilities") has been the challenges they create for the operation of their grids. Specifically, these resources cause them to have to increase reserves in general; increase spinning reserves; are susceptible to rapid "ramp up" and "ramp down" rates; cause traditional utility generation to operate out of merit dispatch; increase overall fuel and other variable operating expenses; and essentially have little to no firm capacity due to their non-dispatchability and uncertainty of operation.[4]

Solar facilities that add energy storage such as batteries and provide more predictable output may help reduce some of these issues.[5] The challenge for utilities and the Commission is how to allow for this development of paired battery storage with both future and existing solar qualifying facility (QF) generation and provide these benefits in a way that is fair to ratepayers. Some of the positions articulated by the utilities in this docket would, in my opinion, frustrate the addition

[4] *See, e.g.*, the direct testimony of Duke witness John Samuel Holeman III at 9-15,filed on February 21, 2017, in Docket No. E-100, Sub 148.

[5] The Public Staff recognizes that other energy storage systems, such as flywheels and compressed air technologies may also provide similar benefits to battery storage systems, so the discussion in this testimony would equally apply to those technologies should they become commercially viable.

OFFICIAL COPY OFFICIAL COPY

Jul 03 2019 Jul 29 2019

of battery storage,[6] despite storage having the potential to provide "system and retail customer benefits if existing solar facilities were able to use energy storage to shift their output away from those times when the sun is shining, or to smooth the delivery of energy during times of sporadic sunshine."[7]

Q. WHAT AVOIDED COST RATE SCHEDULE DO THE UTILITIES INDICATE SHOULD BE APPLICABLE WHEN A QF ADDS BATTERY STORAGE TO AN EXISTING FACILITY?

A. In the supplemental testimony of Glen Snider, Duke indicates that a "committed" QF proposing to integrate battery storage should: (a) not be allowed to do so without the utility's consent; and (b) be required to enter into a new or modified power purchase agreement (PPA) at the Companies' then-current avoided cost rates.[8] Similarly, DENC witness Billingsley testified that in all three of the scenarios presented by the Commission, the current avoided cost rates and terms would apply, meaning that a QF seeking to add storage to an existing facility would have to establish a new LEO and execute a new PPA

---

[6] *See e.g.*, the March 27, 2019, reply comments of Duke at 137-148; the May 21, 2019, testimony of Duke witness David B. Johnson at 6-8; the June 25, 2019 testimony of Glen A. Snider, at 7-10; and the June 25, 2019 supplemental testimony of DENC witness James M. Billingsley at 7.

[7] Sub 101 Order at 27.

[8] Supplemental testimony of Glen A. Snider at 5-6.

OFFICIAL COPY
Jul 03 2019
OFFICIAL COPY
Jul 29 2019

at the then-current avoided cost rates and terms for the entire output of the facility.[9]

Q. WHAT AVOIDED COST RATE SCHEDULE DOES THE PUBLIC STAFF BELIEVE SHOULD BE APPLICABLE WHEN A QF ADDS BATTERY STORAGE TO AN ELECTRIC GENERATION FACILITY THAT HAS ESTABLISHED A LEGALLY ENFORCEABLE OBLIGATION (LEO), EXECUTED A PPA, OR COMMENCED OPERATION?

A. The Public Staff agrees with the utilities that a QF seeking to add any additional energy output to the grid as a result of the addition of battery storage should be compensated for the additional energy at the most current avoided cost rates approved at the time the QF commits to sell the additional energy from the battery storage to the utility. However, the Public Staff does not necessarily agree with the utilities that a QF should lose its eligibility for the rates it established for the original output (contract capacity and energy) of facility that the QF committed to sell to the utilities.

Q. WHY IS IT APPROPRIATE FOR "ADDITIONAL ENERGY" PUT TO THE GRID TO BE PAID AT THE CURRENTLY APPROVED AVOIDED COST RATE SCHEDULE AND RATES?

---

9 Supplemental Testimony of James M. Billingsley at 2-3.

333
OFFICIAL COPY
JUL 03 2019
OFFICIAL COPY
JUL 29 2019

A. As stated by both Duke witness Snider[10] and DENC witness Billingsley,[11] the avoided cost rate schedules and the rates for energy and capacity established in prior avoided cost proceedings no longer reflect the current avoided costs of each utility. Paying QFs for "additional energy" at old avoided cost rates would be unfair to ratepayers, as they [ratepayer] would no longer be indifferent between energy supplied by a QF and energy generated by the utility.[12]

Q. PLEASE CLARIFY YOUR USE OF THE TERM "ADDITIONAL ENERGY."

A. For the purposes of addressing the Commission's questions in this proceeding, I am characterizing "additional energy" as that energy produced by a generation source (in this case, the QF) and either provided to the grid or stored for future use in another medium (in this case, the battery) that is greater than the energy output of the stand-alone QF facility as designed and studied during the facility's original interconnection request, and that formed the basis for the original LEO.[13] To be clear, it is not the Public Staff's position that a

[10] See Supplemental Testimony of Glen A. Snider at 6-8.

[11] See Supplemental Testimony of James M. Billingsley at 4.

[12] The concept of paying a QF the utility's avoided cost rate is predicated on the ratepayer's indifference between the source of energy and capacity, including whether it is from a QF or from another source, including the utility building and owning its own generation facility.

[13] Deviations from the preliminary estimates of an electric generation facility's output can occur from the commissioned or as-built configuration of an electrical generator without storage or other facility alteration/modification. The intent here is to point out the fact that

OFFICIAL COPY
OFFICIAL COPY
Jul 03 2019
Jul 29 2019

solar QF should be able to increase the contract capacity (alternating current. or AC) of its facility without establishing a new LEO and entering into a PPA at the utility's current avoided cost rates.[14]

Q. IS IT POSSIBLE TO PRODUCE "ADDITIONAL ENERGY," AS YOU ARE CHARACTERIZING IT, WITHOUT ADDING BATTERY STORAGE?

A. Yes. It is generally accepted that solar panel prices have been declining for several years, and technological advances have also increased the energy generation capability of solar modules. Given the uncertainty regarding future module prices, some QFs may decide to "re-panel" and/or "over-panel"[15] a facility to increase its capacity (MW_{DC}). Increasing the MW_{DC} via over-paneling or re-paneling does not necessarily increase the nameplate capacity rating (MW_{AC}), as this is dependent upon the inverter and other equipment limitations (e.g. conductors, transformers, etc.). This increase in DC capacity would, however, increase the facility's DC to

different analytics to establish a QF generation baseline or comparison point will need to occur. For example: if battery storage or other material alteration/modification occurs during the design phase but after the System Impact Study in the NCIP, the output production of the facility would need to be evaluated differently versus a facility that is already built with years of historical operation experience.

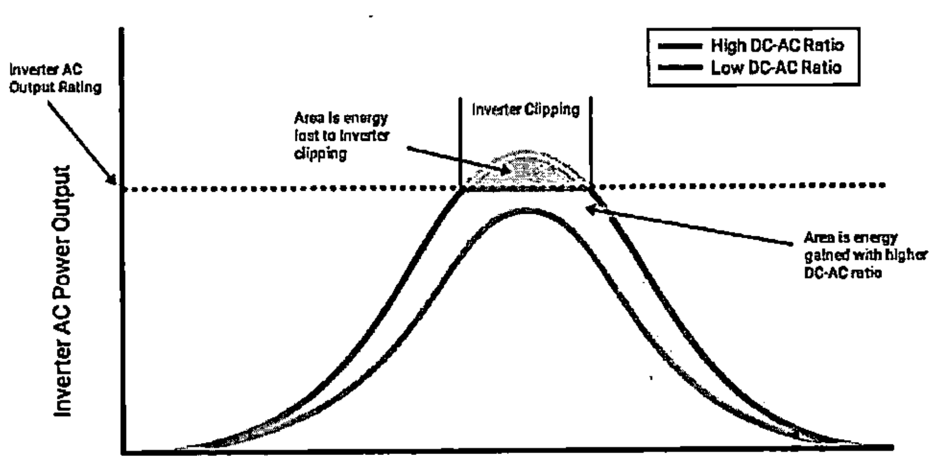
[14] The provision of "additional energy" would however, result in the QF being compensated for both the avoided capacity and energy value, due standard avoided cost rates being paid in North Carolina on a per-kWh basis.

[15] Re-paneling generally refers to the practice of replacing old or damaged solar modules with additional, more efficient modules. Over-paneling generally refers to the practice of increasing the ratio of the facility's direct current (DC) capacity to its alternating current (AC) capacity, typically by installing additional or more efficient modules relative to the inverter size.

OFFICIAL COPY
JUL 03 2019
OFFICIAL COPY
JUL 29 2019

AC conversion ratio,[16] resulting in faster ramp rates and increased "clipped" energy during times of high solar irradiance, as the AC output from the facility is limited by the inverter (see Figure 1 below).[17]

Figure 1: A visual representation of clipped energy.[18]



I have included Figure 1 to demonstrate that the issue of putting "additional energy" to the grid, and the applicable avoided cost rates, demonstrate that the issue at hand of is not limited solely to battery storage. Re-paneling or over-paneling deployed at scale are two other examples of facility changes that can have material impacts on a facility's production profile and the total energy produced.

---

[16] The DC to AC ratio can also be referred to as the inverter loading ratio (ILR).

[17] It is a common practice to install solar panels such that during times of high solar irradiance, the output from the panels exceeds the DC to AC conversion capability of the inverter, resulting in "clipped" energy, but also resulting in a more constant supply of energy to the grid during certain time period.

[18] Source of graphic: https://www.electronicsmedia.info/2017/05/09/solar-inverter-clipping/, June 2019.

OFFICIAL COPY
OFFICIAL COPY

JUL 03 2019
JUL 29 2019

Q. WOULD OVER-PANELING OR RE-PANELING BE CONSIDERED A MATERIAL MODIFICATION TO AN EXISTING PPA ENTERED INTO UNDER EARLIER AVOIDED COST RATES?

A. This is unclear. In its November 1, Application, Duke indicated that modifications to utility-scale solar QFs that could constitute an event of default include "any increase to the AC or DC capacity of the generating facility, such as adding additional solar panels or replacing existing panels with panels with greater DC capacity, increasing inverter capability, or adding batteries or other technologies for the storage and later injection of energy."[19] However, there was not a bright line rule under existing contracts for distinguishing whether or not the replacement or addition of solar modules is a material alteration, or whether or not the QF is addressing aging or damaged equipment by making reasonable continued investments to maintain the operation of the system. Duke therefore included a number of proposed changes to its standard offer PPA and Terms and Conditions going forward to clarify this issue and avoid future disputes over these matters.

NCSEA raised questions about these proposed limitations in the affidavit filed by North Carolina Sustainable Energy Association (NCSEA) witness Benjamin F. Johnson, noting that Duke's proposal

[19] Initial Statement of DEC and DEP at 35.

OFFICIAL COPY OFFICIAL COPY

JUL 03 2019 JUL 29 2019

would not only stifle competition and prevent QFs from experimenting with new technologies, but also potentially prevent QFS from making repairs or replacements to existing facilities.[20]

Q. WOULD OVER-PANELING AND RE-PANELING BE CONSIDERED MATERIAL ALTERATIONS TO A PPA ENTERED INTO PURSUANT TO DUKE'S PROPOSED SCHEDULE PP TERMS AND CONDITIONS?

A. In response to NCSEA's initial comments, the testimony of Duke witness David B. Johnson provided a definition of "material alteration" in its proposed modification to its Schedule PP PPA terms and conditions:

> "Material Alteration" as used in this Agreement shall mean a modification to the Facility which renders the Facility description specified in this Agreement inaccurate in any material sense as determined by Company in a commercially reasonable manner including, without limitation, (i) the addition of a Storage Resource; (ii) a modification which results in an increase to the Contract Capacity, Nameplate Capacity (in AC or DC), generating capacity (or similar term used in the Agreement) or the estimated annual energy production of the Facility (the "Existing Capacity"), or (iii) a modification which results in a decrease to the Existing Capacity by more than five (5) percent. <u>Notwithstanding the foregoing, the repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%) shall not be considered a Material Alteration</u>.[21]

[20] Attachment 1, p. 56, of NCSEA's Initial Comments, filed February 12, 2019.
[21] See Direct Testimony of David B. Johnson at 8 (emphasis added), filed May 21, 2019.

It appears that under this proposed language, over-paneling and re-paneling would not likely be considered a material alteration so long as the Existing Capacity is not increased, and a decrease in Existing Capacity would only be considered a material modification if it decreased by more than five percent.[22] As noted in the June 21, 2019, testimony of Public Staff witness Hinton, a degree of reasonableness should be applied to these thresholds, and the Companies should review these revisions in a commercially reasonable manner.[23]

Q. CAN YOU DESCRIBE THE DIFFERENCE BETWEEN A MATERIAL ALTERATION AND A MATERIAL MODIFICATION?

A. Yes. The Commission's June 14, 2019, *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony* issued in Docket No. E-100, Sub 101, included revisions to NCIP Section 1.5 and extensively discussed material modifications. While the definition of "material alteration," a commercial term applicable to Schedule PP only, is straightforward, the definition of "material modifications" in the NCIP is more extensive. Of particular relevance

[22] I note that the last statement in the Material Alteration definition may be interpreted differently, and as such, recommend that to the extent the Commission adopts the Material Alteration definition proposed by Duke, that it insert commas to clarify the paragraph, as follows:

> "Notwithstanding the foregoing, the repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity, or decrease the Existing Capacity by more than five percent (5%), shall not be considered a Material Alteration."

[23] Testimony of John R. Hinton in Docket No. E-100, Sub 158, at 18. June 21, 2019.

OFFICIAL COPY
Jul 29 2019

OFFICIAL COPY
OFFICIAL COPY
Jul 03 2019
Jul 29 2019

to this discussion, Section 1.5.2.2 provided that to the extent an interconnection customer had not executed a System Impact Study Agreement, the following would not be considered indicia of a material modification:

> 1.5.2.1.1 A change in the DC system configuration to include additional equipment including: DC optimizers, DC-DC converters, DC charge controllers, power plant controllers, and energy storage devices, so long as the proposed change does not violate any of the provisions laid out in Section 1.5.1.1.

In addition, Section 1.5.2.2 found that the following are not indicia of material modification at any time:

> ...
>
> 1.5.2.2.2 A change or replacement of generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying controls, etc. that is a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;
>
> 1.5.2.2.3 An increase in the DC/AC ratio that does not increase the maximum AC output capability of the Generating Facility;
>
> 1.5.2.2.4 A decrease in the DC/AC ratio that does not reduce the AC output capability of the Generating Facility by more than 10%.
>
> 1.5.2.2.5 A change in the DC system configuration to include additional equipment that *does not impact* the Maximum Generating Capacity, daily production profile or the proposed AC configuration of the Generating Facility including: DC optimizers, DC-DC converters, DC charge controllers, power plant controllers, and energy storage devices such that the output is delivered during the same periods and with the same profile considered during the System Impact Study. (emphasis added)

OFFICIAL COPY
OFFICIAL COPY
JUL 03 2019
JUL 29 2019

With regard to the addition of energy storage, two significant differences between these definitions appear to be as follows:

1) Under Schedule PP, the addition of an energy storage resource or a change in the estimated annual energy production would potentially trigger a material alteration; whereas under the NCIP, the addition of an energy storage resource would not trigger a material modification if it were made prior to the System Impact Study Agreement, or after the execution of the System Impact Study Agreement, so long as the output is delivered during the same periods and with the same profile considered during the System Impact Study.

2) Similarly, under Schedule PP, the repair or replacement of equipment with like-kind equipment would not be a material alteration so long as the estimated annual energy production was not increased, or in the event that the repair or replacement decreased the estimated annual energy production, that did not decrease by more than five percent. Under the material modification provision, this determination is based on whether output is delivered during the same periods and with the same profile considered during the System Impact Study.

OFFICIAL COPY
OFFICIAL COPY

Jul 03 2019
Jul 29 2019

Q. DO YOU BELIEVE THAT ADDING BATTERY STORAGE, OR OTHER CHANGES THAT RESULT IN "ADDITIONAL ENERGY" OUTPUT THAT YOU DISCUSSED EARLIER, WHEN APPLIED TO ANY OF THE THREE SCENARIOS OUTLINED BY THE COMMISSION (E.G., LEO, EXECUTED PPA, OR OPERATIONAL FACILITY) CONSTITUTE A MATERIAL MODIFICATION?

A. In regards to a facility that has established a LEO, such determination would be dependent on whether or not any of the criteria listed in Section 1.5 in the NCIP were triggered. As noted above, Section 1.5.2.2.5 of the NCIP contains a condition that uses the subjective word "impact". Unlike the term "material alteration," which establishes clear triggering condition(s), certain aspects of "material modification" would be subject to interpretation by the utility. Given the current language of NCIP Section 1.5.2.2.5, however, I would classify a change such as the addition of battery storage that results in "additional energy" as a material modification only if it changed the facility's daily production profile.

For a QF with an executed PPA or that has commenced operation and wanted to add battery storage, I believe the QF would need to engage with the interconnecting utility and submit documentation to allow the utility to review the changes "in a commercially reasonably manner." In the event that the battery storage or other changes that result in "additional energy" is added beyond the studied state of the facility, or the state of the facility when it commenced operation, the "additional energy" put to the grid should be paid at the most recent avoided cost schedule and rates.

Q. WHAT CHALLENGES EXIST IN DETERMINING WHEN AND HOW TO PAY DIFFERENT RATES TO QFS FOR ITS EXISTING GENERATION OUTPUT AND "ADDITIONAL ENERGY?"

A. There are several issues that the Commission should take into consideration and evaluate in more detail, including engineering and technical challenges, impacts on the interconnection queue, and the applicable commercial terms and conditions.

Q. PLEASE DISCUSS SOME OF THE ENGINEERING CHALLENGES ASSOCIATED WITH ADDING BATTERY STORAGE TO AN EXISTING FACILITY.

A. Throughout the course of the filings in this docket, there has been extensive discussion of whether co-located battery output could be measured by the utilities.[24] Based upon my experience as a system designer and integrator as well as some preliminary research, there are multiple possibilities to measure output of co-located batteries (equivalent to two energy sources being dual monitored). However, engineered solutions will need to go hand in hand in consideration with commercial terms and condition revisions. I would also note that

[24] Duke Energy Reply Comments at 141-144, filed March 27, 2019.

OFFICIAL COPY
Jul 03 2019
OFFICIAL COPY
Jul 29 2019

OFFICIAL COPY
Jul 29 2019

pending the engineered solutions for measuring co-located batteries or further restrictions of commercial terms and conditions, it may prove to be uneconomical due to required capital and risk analysis. Other engineering challenges include the operational requirements to allow the utility to: (a) have sufficient control over the charging, discharging, and operational characteristics of numerous QFs equipped with battery storage with varying manufacturer specifications, and (b) monitor the varying configurations of battery storage on its system over time. Both of these challenges would trigger additional costs and expenses, and would require additional oversight to ensure that costs are properly booked and allocated.

Q. WHY IS THE INTERCONNECTION QUEUE RELEVANT TO THIS DISCUSSION OF AVOIDED COSTS APPLICABLE TO THE ADDITIONAL ENERGY FROM QFs THAT INSTALL BATTERY STORAGE FACILITIES?

A. In the Commission's Sub 148 Order, the Commission explicitly recognized the linkage between the determination of applicable avoided cost rates and the interconnection process by adding a fourth requirement to the Commission standard for the establishment of a LEO requiring a QF to submit a completed interconnection request pursuant to the NCIP, at which time a timetable for establishing a LEO commenced based on the characteristics of the

OFFICIAL COPY

Jul 29 2019

facility and its relative position in the interconnection queue.[25] Because of this linkage between avoided costs and the NCIP, any modifications or revisions to procedures in an avoided cost docket may have cascading impacts on the NCIP and vice versa.[26] In the Commission's Sub 101 Order, the Commission directed the utilities to report back on the development of:

> a streamlined process for efficiently studying the addition of storage at existing generation sites and that builds upon the grouping study approach that is already under development as required by the Stipulation; and (2) details of how the addition of storage to the direct current side of an existing generator would impact the facility's original System Impact Study results.[27]

It is unclear at this time how the Utilities will evaluate these requirements, following the completion of the report, what further consideration of commercial terms and conditions on impacts and implementation will be necessary.

Q. DO YOU PROPOSE ANY SPECIFIC MODIFICATIONS TO THE COMMERCIAL TERMS AND CONDITIONS?

A. Other than the recommendation to slightly modify the definition of "material alteration" discussed earlier in my testimony, I do not have further recommendations to modify the terms and conditions at this

[25] Sub 148 Order at 104-106.

[26] The Commission recognized this linkage in the Sub 101 Order and its June 14, 2019 *Order Requiring Supplemental Testimony and Allowing Responsive Testimony* in this Docket.

[27] Sub 101 Order at 28.

OFFICIAL COPY

Jul 29 2019

time. The complexity of allowing a QF to put "additional energy" to the grid while still requiring it to also meet its original contract capacity and energy commitments, however, should be further evaluated. While I am not an attorney, I have worked on and reviewed several performance guarantee terms and conditions, and have some understanding of the complexity involved. Commercial terms for performance guarantees necessarily have some degree of engineering/technical evaluation to ensure that a milestone or goal can be properly validated. Any implementation of controls to monitor system operations will potentially increase costs to the overall system. Therefore, if a change did occur to allow battery storage to be added to an existing project, the terms and conditions of the PPA and the Interconnection Agreement may need modification from their current state to ensure consistency and compliance.

For example, if an existing facility sought to add battery storage and took the position that the output from the battery storage could be separately measured, a methodology would have to be created to establish the criteria for calculating a baseline generation from the existing facility for comparison purposes.[28] Other commercial terms

[28] Methodologies for calculating a baseline could involve a single year generation average, use of a PV Watts© model run of a similar facility at another site, a three to five year average of historical operation, or even a hybrid calculation using multiple approaches. It is also possible that no base line may need to be created if the site is using the battery only to remove intermittency from the non-battery portion of the facility (no energy shifting or price arbitrage). Because there are multiple iterations of how additional energy could be put to the grid, adopting a one size fits all approach would be problematic.

OFFICIAL COPY

Jul 29 2019

and conditions may also need to be modified, as the circumstances of each facility may be different.

Another possibility that may be considered is to allow all output from the battery, inclusive of system losses as required, to be paid at the most recent avoided cost rates. Even this simplified approach, revisions to the existing PPA is a possibility and or linkage of a new PPA to the term of the old PPA will need to be taken into consideration.

Q. DO YOU HAVE ANY FURTHER COMMENTS OR RECOMMENDATIONS FOR THE COMMISSION TO CONSIDER AT THIS TIME?

A. The topics and specific items identified in my testimony are not an exhaustive list of all potential issues. The Public Staff continues to evaluate potential "what if" scenarios and avoided cost design considerations associated with the potential large-scale implementation of battery storage added to existing QFs. Due to the complexity of this topic, it may be appropriate for the Commission to consider forming a working group between the developers, meter manufacturers, system design/integrators, and the Utilities to look at technology implementation of measuring co-located battery output. The dynamic nature of technology changes coupled with regulatory challenges and commercial terms and conditions create challenges,

OFFICIAL COPY

Jul 09 2019

most of which have not been precisely communicated between the stakeholders. I believe that some of these challenges could be overcome by further focused discussion between stakeholders with a relatively truncated timeline. The timeline of this working group should be started within 60 days of the Commission's order on this proceeding and seek within a reasonable timeframe to develop: (a) a potentially deployable solution; or b) further identify specific challenges that would prevent the commercial viability of adding energy storage to existing facilities.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, this concludes my testimony.

OFFICIAL COPY

Jul 29 2019

APPENDIX A

Dustin R. Metz

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, 2008 and 2009 respectively. I graduated from Central Virginia Community College with Associates of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude), 2011 and 2012 respectively, and an Associates of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management.

I have over 12 years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical & electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on general rate cases, fuel cases, applications for certificates of public convenience and necessity, customer complaints, nuclear decommissioning, power plant performance, and other aspects of utility regulation.

OFFICIAL COPY

Jul 29 2019

BY MR. DODGE:

Q Mr. Metz, did you prepare a summary of your testimony?

A Yes, I did.

Q Would you please provide it at this time?

A Good afternoon. The purpose of my testimony is to address specific issues detailed by the North Carolina Utilities Commission in its June 14th, 2019 Order Requiring Supplemental Testimony and Allowing Responsive Testimony. In that Order the Commission required testimony -- correction -- requested testimony from the Public Staff to address what avoided cost rate schedule and contract terms and conditions apply when a qualifying facility adds battery storage to an electric generating facility.

The complementary function of energy storage, when paired with intermittent generation, can reduce needed system reserves by improving predictability of energy output, alleviate other challenges to the electrical grid, and increase overall dependable capacity. Therefore, energy storage coupled with solar generation has the potential to provide benefits to ratepayers and should be appropriately encouraged and fairly treated.

OFFICIAL COPY

Jul 29 2019

Any additional energy put to the electrical grid from an already existing QF, whether commercially operational or studied as part of the facility's original interconnection request, should be compensated at the most current avoided cost rates and schedules.

Duke proposes to modify its Schedule PP standard offer PPA contract to include the definition of material alteration as a commercial term to be applicable to QF facilities establishing a legally enforceable obligation under this docket. While material alteration is specific only to the projects which qualify for Schedule PP under this docket, the broader definition of material modification in the context of the North Carolina interconnection procedures is more extensive and applies to new and existing facilities. A material alteration allows some degree of flexibility to the QF for facility life cycle planning, but as proposed by Duke, would not allow energy storage to be added. A material modification, on the other hand, is triggered if the output of the generation facility, i.e., production profile, is modified from the profile considered during the system impact study. In summary, the addition of energy storage would definitely trigger a material alteration, and more likely than not trigger a material

OFFICIAL COPY

Jul 29 2019

modification due to the changes in the facility's daily production profile.

While not intended to be exhaustive, throughout my testimony I have attempted to bring attention to the Commission certain specific topics to address the challenges and complexities in implementing a policy that would allow existing QFs continue to earn their previously established avoided cost rates for the original output of the facility, but earn the most current avoided cost rates for the additional energy output of the facility resulting from the addition of energy storage. The dynamic nature of technology changes in the energy storage arena, coupled with regulatory challenges and established commercial terms and conditions, create challenges that have not been precisely communicated between the stakeholders. In my testimony I have proposed a focused stakeholder discussion with a truncated timeline to explore and develop a deployable solution and to identify specific challenges that prevent the commercial viability of adding energy storage to existing facilities.

This completes my summary.

MS. CUMMINGS: Thank you, Mr. Metz.

DIRECT EXAMINATION BY MS. CUMMINGS:

OFFICIAL COPY

Jul 29 2019

Q And now turning to Mr. Thomas, would you please state your name and address for the record?

A (Thomas) Good afternoon. My name is Jeff Tyler Thomas.

Q And your address, for the record?

A 430 North Salisbury, Raleigh, North Carolina.

Q By whom are you employed and in what capacity?

A I'm a Utilities Engineer with the Public Staff Electric Division.

Q Did you cause to be prefiled on June 21st, 2019 in this docket testimony consisting of 44 pages, one appendix, and six exhibits?

A Yes.

Q And at this time do you have any changes or corrections to your testimony?

A Yes. I have a few minor changes. On page 32, line 3 of my testimony, please strike the second not so that the sentence should read "Therefore, I do not believe it is appropriate to enforce the energy storage protocol." In addition, on page 9, line 4, please change the word wind to solar. And in a related change on page 10, Footnote 12, change the word between Idaho Power and 2016 from wind to solar.

Q Thank you. And other than those changes, if I

OFFICIAL COPY

Jul 29 2019

asked you the same questions today, would your answers be the same?

A Yes, they would.

Q Thank you.

MS. CUMMINGS: Madam Chair, at this time I move that the prefiled testimony and appendix of Jeff Thomas be entered into the record as if given orally from the stand, and that his exhibits be marked for identification as premarked in the filing.

CHAIR MITCHELL: The motion is allowed.

(Whereupon, the prefiled testimony of Jeff Thomas, as corrected, was copied into the record as if given orally from the stand.)

(Whereupon, Thomas Exhibits A through G were identified as premarked.)

OFFICIAL COPY

Jul 29 2019

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of		
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	))))))	TESTIMONY OF JEFF THOMAS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

OFFICIAL COPY

Jul 29 2019

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

A. My name is Jeff Thomas. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Exhibit A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's position on proposed modifications to the avoided cost rates of Duke Energy Progress, LLC ("DEP"), Duke Energy Carolinas, LLC ("DEC") (collectively, "Duke"), and Dominion Energy North Carolina ("DENC") (collectively, "the Utilities"). Specifically, I will address the following issues identified by the Commission as meriting consideration at an evidentiary hearing:

I. Duke's quantification of ancillary services cost of integrating Qualifying Facility ("QF") solar;

II. Duke's proposed solar integration charge "average cost" rate design and biennial update;

OFFICIAL COPY

Jul 29 2019

III. DENC's proposed re-dispatch charge ("RDC");

IV. NCSEA's and Public Staff's proposals related to differing ancillary services costs for innovative QFs;

V. Duke's Proposed Modifications to the Standard Terms and Conditions as related to the Energy Storage Protocol;

VI. The stipulation between Duke and the Public Staff filed on April 18, 2019, related to energy and capacity rate design.

I will also propose rule changes to R8-64 and R8-71 that are related to the rate design stipulation. My testimony should be considered in conjunction with that of Public Staff witness Bob Hinton.

I. Duke's Quantification of Ancillary Services Cost of Integrating QF Solar

Q. WHAT IS THE PURPOSE OF DUKE'S PROPOSED SOLAR INTEGRATION SERVICES CHARGE?

A. Duke asserts that the purpose of the Solar Integration Services Charge ("SISC") is to quantify and recoup the costs it incurs from to the injection of power from intermittent QFs into its electric grid. The general argument is that the intermittent and non-dispatchable nature of renewable technologies, such as standalone solar photovoltaics ("PV"), results in additional system costs to integrate these sources of energy. This issue is exacerbated because the

OFFICIAL COPY

Jul 29 2019

majority of the solar PV on the Utilities' grids are "must-take" facilities under the federal Public Utilities Regulatory Policies Act of 1978("PURPA"), with limited ability for the Utilities to curtail or dispatch these facilities outside of emergency situations.

Public Staff witness Dustin Metz testified on the issue of integrating significant solar QF capacity in the 2016 biennial avoided cost proceeding, Docket No. E-100, Sub 148 ("Sub 148"). Mr. Metz explained that as solar QF capacity increases under PURPA, Duke faces "increasing operational challenges as they seek to maintain the proper amount of contingency reserves that can be 'ramped up' and 'ramped down' in real time to meet resulting demand/supply imbalances."[1]

Q. DOES THE PUBLIC STAFF AGREE WITH THE GENERAL ARGUMENT PUT FORTH BY DUKE TO JUSTIFY THE PROPOSED SISC?

A. Yes. The Public Staff agrees that integrating intermittent, non-dispatchable energy sources cause system operators to make decisions and deploy the fleet of Utility-owned generation assets in ways that can increase costs to ratepayers. This concept is generally uncontroverted within this proceeding. These increased system

[1] *See* March 28, 2017, testimony of Dustin R. Metz in Docket No. E-100, Sub 148, at 6-7.

OFFICIAL COPY

Jul 29 2019

costs, reflecting increased fuel consumption and operations and maintenance expenses, are ultimately passed on to ratepayers through base rates and annual fuel rider adjustments.

Q. PLEASE PROVIDE AN EXAMPLE OF THE INCREASED COSTS THAT ARE PASSED ON TO RATEPAYERS.

A. As noted in the testimony of Duke witness Glen A. Snider, Duke's SISC is designed to recoup costs stemming from the increased ancillary services required to have sufficient on-line generation ramping capabilities to meet intra-hour unplanned fluctuations in solar output (such as cloud cover). These increased system costs are due to (1) thermal units operating outside their optimal output range, and (2) additional dispatchable units operating in standby mode, ready to respond within minutes to meet applicable North American Electric Reliability Corporation ("NERC") balancing requirements.[2]

Q. PLEASE DESCRIBE THE METHODOLOGY USED BY DUKE TO QUANTIFY THESE COSTS.

A. Duke contracted with Astrapé Consulting ("Astrapé"), which utilized a proprietary reliability-based probabilistic model to determine the level of frequency regulation reserves necessary to meet load in five

[2] Direct Testimony of Glen A. Snider at 36-37.

OFFICIAL COPY

Jul 29 2019

minute increments. As solar PV penetration increases in iterative model runs, the amount of frequency regulation reserves are increased to maintain the same level of system reliability as in the base case with no solar.

Q. DID THE PUBLIC STAFF IDENTIFY ISSUES WITH DUKE'S QUANTIFICATION OF THE SISC?

A. Yes. We identified four technical concerns with the Astrapé study in our initial comments.[3] As described in our reply comments, we later withdrew some of these concerns based upon additional discovery and communication with Duke.[4] The Public Staff also supported the analysis of Southern Alliance for Clean Energy ("SACE") witness Kirby of the reliability standards imposed on the model by Duke and Astrapé.

Q. PLEASE BRIEFLY SUMMARIZE YOUR CONCERNS WITH THE ASTRAPÉ STUDY.

A. The Public Staff's initial technical concerns regarding the SISC focused on the following items:

[3] One additional concern related to the biennial update, which is addressed later in this testimony.

[4] Reply Comments of the Public Staff at 17.

OFFICIAL COPY
Jul 29 2019

- The Astrapé model portrayed DEC and DEP as load islands, unable to rely on each other or neighboring utilities and regional transmission organizations ("RTOs") to meet the intra-hour fluctuations in demand and solar output.[5]
- The justification for the "base case", which included no solar capacity, excluding even utility-owned solar resources.[6]
- The limited amount of data used to quantify solar volatility on five minute intervals, and the potential for inaccuracy of the study's estimates of solar volatility, and therefore the integration costs, due to the geographical diversity of future solar generation facilities.[7]
- The modeler's addition of "load following up" reserves and the exclusion of other types of ancillary services that are capable of meeting intra-hour fluctuations in real time.[8]
- The assertion, based on the analysis of SACE witness Kirby, that if Duke used a reliability standard that was too stringent, it would drive up the amount of ancillary reserves required to meet intra-

[5] Initial Statement of the Public Staff at 39. DEP and DEC were able to rely on market purchases to meet capacity shortfalls (i.e., load exceeds demand with all generation units at maximum production), but not ramping shortfalls (i.e., demand increases faster than on-line generation units can ramp up output).
[6] Id. at 39-40.
[7] Id. at 40-41.
[8] Id. at 42.

OFFICIAL COPY

Jul 29 2019

hour fluctuations in solar output, thus resulting in integration cost estimates that are higher than actual costs incurred.[9]

Q. HAS DUKE WORKED WITH THE PUBLIC STAFF TO RESOLVE THESE CONCERNS?

A. Yes. Both Duke and Astrapé made technical staff available for multiple conference calls, responded to multiple data requests, and provided additional analysis, some of which is included in Duke's Reply Comments.[10]

Q. IS THE PUBLIC STAFF AWARE OF ANY OTHER INTEGRATION STUDIES UTILIZED BY OTHER UTILITIES?

A. Yes. The Public Staff performed a brief review of integration studies from several other utilities to compare methodologies, assess how the studies were conducted, whether the utilities were modeled as load islands, and what metrics were used to evaluate the system impact of intermittent resources. The studies, a summary of which is included as Exhibit B, are listed below by utility, generation technology, and study year:

- Xcel Energy (Public Service Company of Colorado), wind, 2011;
- Arizona Public Service, solar, 2012;

[9] Reply comments of the Public Staff at 18.
[10] Duke Reply Comments at 92-94.

OFFICIAL COPY

Jul 29 2019

- Xcel Energy (Public Service Company of Colorado), solar, 2013;
- Idaho Power, wind, 2013;
- Xcel Energy (Public Service Company of Colorado), solar, 2016;
- Idaho Power, wind, 2016;
- South Carolina Electric & Gas Company, solar, 2019.

While every approach taken in the integration studies was different, the Public Staff's review indicated that Duke's proposed SISC is generally reasonable and within the range of the other studies.

Q. WHY DOES THE PUBLIC STAFF NO LONGER BELIEVE THAT MODELING DEC AND DEP AS LOAD ISLANDS IS INAPPROPRIATE?

A. The Public Staff had a conference call with Duke system operators, who spoke in detail about the process for scheduling the load following reserves necessary to respond to intra-hourly fluctuations in solar output and load. This process does not incorporate any data from other utilities; that is, when DEP sets its required ancillary services for a particular day or hour, it does not consider the state of the DEC system. In addition, Duke's reply comments and the testimony of witness Nick Wintermantel provide a reasonable rationale as to why the utilities are modeled as load islands for the purposes of intra-hour regulation reserves – specifically, the discussion that while the Joint Dispatch Agreement between DEC

OFFICIAL COPY
Jul 29 2019

and DEP allows for excess energy transfers of non-firm energy, it does not support the firm capacity that would be required to provide the intra hour ancillary services needed to manage the variability in solar output.[11]

Finally, the Public Staff reviewed intermittent generation integration cost studies from several other states, and found that modeling utilities as load islands with limited or no ability to rely upon neighboring utilities for real-time solar and wind output fluctuations is not uncommon.[12] Several of these studies allowed the utility to purchase energy and capacity from neighboring utilities, but not for the purposes of maintaining reserves – similar to how the Astrapé model portrayed DEC and DEP.[13]

Q. WHY DOES THE PUBLIC STAFF BELIEVE THAT IT IS APPROPRIATE TO MODEL A BASE CASE WITH NO SOLAR?

A. By removing all solar from the base case and then studying the integration cost of all solar, Duke effectively aggregates the system costs imposed by both QF solar and utility-owned solar. Solar QFs

[11] *Id* at 86-91; Direct Testimony of Nick Wintermantel, at 27.

[12] The Public Staff found that the following studies modeled their utilities as "load islands" for the purposes of real time operations (utility, generation technology, study year): Arizona Public Service, solar PV, 2012; Idaho Power, wind, 2013; Idaho Power, wind, 2016; SCE&G, solar, 2019.

[13] Market purchases at costs above a gas combustion turbine were included in both DEC and DEP systems to provide enough capacity to meet demand. Market purchases were not permitted when enough capacity existed but intra-hour ramp rate constraints caused an LOLE_{FLEX} violation. See Astrapé Solar Ancillary Service Study at 8-10.

OFFICIAL COPY

Jul 29 2019

are then charged the average SISC, while ratepayers pay for the integration of utility-owned solar. Under this methodology, ratepayers and solar QFs pay the same average cost for the integration of utility-owned and QF-owned solar.

If utility-owned solar had been included in the base case, that would result in a higher solar integration cost assigned to solar QFs than to utility-owned solar, because the incremental cost of integrating solar resources increases as solar penetration increases. If utility-owned solar had not been included in the calculation of the average service charge, the result would be higher integration costs assigned to utility-owned solar (and therefore ratepayers) than those assigned to solar QFs. I believe that the most equitable result is for the SISC to be the same for both QF and utility-owned solar.

Q. WHY DOES THE PUBLIC STAFF BELIEVE THAT THE VOLATILITY DATA USED IS REASONABLE?

A. The Public Staff's concerns regarding data volatility were primarily centered around the integration costs calculated for higher levels of solar penetration, such as 3,020 MW in DEC and 4,610 MW in DEP.[14] The Public Staff still has concerns about how volatility is modeled in these scenarios, as addressed in our initial comments.

[14] See Astrapé Solar Ancillary Service Study at 47-52.

365
OFFICIAL COPY
Jul 29 2019

However, the estimated integration costs associated with these high levels of solar penetration are only projections, and are not being used by Duke to assess any charges in this proceeding. As Duke continues to update their integration cost studies, new solar facilities are constructed and connected to the grid, and additional granular solar output data is collected, the Public Staff expects this issue to generally resolve itself. Duke acknowledges this, stating that they, "... do not dispute that use of more current solar volatility data can impact assumptions over time ... for this reason, the Companies advocate for updating the historic volatility data biennially in future avoided costs proceedings...."[15]

Q. WHY DOES THE PUBLIC STAFF BELIEVE THAT THE FORCED SELECTION OF 'LOAD FOLLOWING UP RESERVES' IN THE ASTRAPÉ MODEL IS REASONABLE?

A. The Public Staff acknowledges that, as Duke identified in their reply comments,[16] Astrapé modeled several different types of ancillary services, such as quick start reserves, regulation requirement up and down, and load following up and down.[17] While only one type is increased to integrate solar (load following up), the number of different services modeled is more granular than several other

[15] Duke Reply Comments at 104.
[16] *Id.* at 113.
[17] *See* Astrapé Solar Ancillary Service Study, Table 18, at 43.

OFFICIAL COPY

Jul 29 2019

integration studies reviewed. While future improvements could be made to the model in order to better optimize the available ancillary services used to meet load as the penetration of renewables increases, it is reasonable for Duke to utilize the load following up reserves at this time.[18]

Q. WHY DOES THE PUBLIC STAFF BELIEVE THAT THE RELIABILITY STANDARDS ADHERED TO IN THE ASTRAPÉ MODEL ARE REASONABLE?

A. Duke and Astrapé provided information to the Public Staff that used post-processing techniques to estimate the impact of increasing the $LOLE_{FLEX}$ metric from 0.1 to both 0.3 and 1.0. Increasing the allowed frequency of events in which load could not be met due to ramping constraints by 10-fold (in the case of a 1.0 $LOLE_{FLEX}$) reduced the average Solar Integration Services Charge by 6.2% in DEC and 1.9% in DEP, due to a reduction in total load following capacity required. The additional analysis provided to the Public Staff is attached heretofore as Exhibit C.

The Public Staff's primary concern was that the change in the average SISC would be significant due to the increasing marginal

[18] Many of the various ancillary services offer similar capabilities and are often comprised of overlapping generation units (i.e., the same unit may be able to provide both 10-minute and 60-minute reserves). In addition, the integration cost studies from other states previously discussed generally only utilized one type of ancillary service.

OFFICIAL COPY

Jul 29 2019

cost of integrating intermittent resources. However, it appears that the loosening of the reliability standard does not have the significant effect that was anticipated by the Public Staff. In addition, the quantity of incremental load following reserves appears to be reasonable compared to the capacity of solar generation resources on the system. As a result of this further analysis, I believe that the substantive concerns the Public Staff had with the quantification of the SISC have been resolved without the need for revisions to the Astrapé study.

Q. OVERALL, DO YOU BELIEVE THAT DUKE HAS MADE A REASONABLE ATTEMPT TO QUANTIFY THE INCREASE IN SYSTEM COSTS DUE TO INTERMITTENT RESOURCES?

A. Yes, I believe that the methodology used to quantify the SISC is reasonable and that assessing this charge on solar QFs is appropriate. This position is supported in more detail by the Stipulation of Partial Settlement between DEC, DEP, and the Public Staff, filed May 21, 2019 ("SISC Stipulation").

II. <u>Duke's Proposed SISC "Average Cost" Rate Design and Biennial Update</u>

Q. PLEASE DESCRIBE HOW DUKE HAS PROPOSED TO ADMINISTER THE SISC.

OFFICIAL COPY

Jul 29 2019

A. Duke plans to apply the charge to all new solar facilities that establish a Legally Enforceable Obligation ("LEO") under the avoided cost rates filed in this proceeding, and to any solar facilities that seek to renew their expiring contracts. Thus, all QF solar facilities will eventually pay the SISC. Duke proposes to charge each solar facility the average integration cost based on the aggregate capacity of solar connected to the grid at the time they establish a LEO, as opposed to the incremental cost associated with a particular block of solar studied by Astrapé. For the SISC included in Schedule PP for DEC and DEP, this represents a charge of $1.10/MWh and $2.39/MWh, respectively, and would reflect the existing plus HB 589 transition ("Existing Plus Transition") solar capacity in DEP (2,950 MW) and DEC (840 MW),

Q. DOES DUKE PLAN TO UPDATE THE CHARGE PERIODICALLY?

A. Yes. Duke proposes to re-run its Astrapé study with updated inputs and levels of solar penetration in each biennial avoided cost proceeding. This recalculated SISC would then apply to all solar facilities subject to the charge; that is, the charge would be refreshed every two years.

Q. DO YOU HAVE ANY CONCERNS WITH THE UPDATE PROCESS?

OFFICIAL COPY

Jul 29 2019

A. Yes. Similar to the Public Staff's position in Sub 148, we have concerns with the uncertainty QFs would face with rates refreshing every two years.[19] In the Astrapé study, Duke calculated the average SISC for higher levels of solar penetration, indicating that the charge could reach as high as $9.75/MWh in DEC and $14.91/MWh in DEP.[20] While Duke has committed to performing this analysis in all future updates to the SISC "to reduce uncertainty,"[21] it does not consider the effect of natural gas price volatility. Fluctuations in the cost of natural gas could cause the projected SISC to be substantially different in future studies, because the majority of units providing regulation reserves are natural gas fired and the study only encompasses one year and does not project natural gas prices into the future. Thus, projecting the SISC at higher solar penetration levels does not address a significant source of uncertainty. The forecast of the higher SISC at higher levels of solar penetration and the additional uncertainty due to the impact of fluctuating natural gas prices may make it difficult to finance solar projects subject to the charge.

[19] Public Staff Initial Comments at 37-39.

[20] *See* Astrapé Solar Ancillary Service Study, Table 20 (DEC) and Table 21 (DEP). These estimates reflect no reduction in solar volatility with the addition of 1,500 MW of solar capacity in addition to existing, transition, and CPRE Tranche 1 capacity.

[21] Duke Reply Comments at 121.

OFFICIAL COPY

Jul 29 2019

Q. DID THE PUBLIC STAFF PROPOSE ANY ALTERNATIVE OPTIONS FOR CONSIDERATION?

A. Yes. We recognize that integration costs can change over time, particularly if Duke's system characteristics or natural gas prices change significantly. As such, we proposed two possible options: (i) charge solar facilities the incremental SISC (which is higher than the average[22]) and eliminate the refresh; or (ii) charge solar facilities the average SISC, and allow a refresh, but implement a reasonable cap on the amount by which the SISC could change to provide certainty to QFs.

Q. HOW DOES THE SISC STIPULATION ADDRESS THIS ISSUE?

A. On May 21, 2019, the Public Staff and Duke filed a Stipulation of Partial Settlement Regarding the Solar Integration Services Charge ("SISC Stipulation"). Section VI of the SISC Stipulation applies a cap on potential future increases of the SISC, stating that the cap is "reasonable and appropriate to mitigate the risk for Sub 158 Vintage solar generators of currently-unquantifiable potential future increases" in the SISC. The cap is calculated by the Astrapé model to determine the incremental integration cost of the last 100 MW of

[22] The average SISC is calculated by dividing the total increase in system costs by the total amount of generation from all solar capacity added to the model. The incremental SISC is calculated by dividing the incremental increase in system costs by the total amount of generation, from the last "block" of incremental solar capacity added to the model.

OFFICIAL COPY

Jul 29 2019

solar expected to be interconnected by the end of the current Sub 158 biennial period (2020), using projections from DEC's and DEP's Integrated Resource Plans ("IRPs"). Under this methodology, the SISC would be capped for Sub 158 Vintage QFs at $3.22/MWh in DEC and $6.70/MWh in DEP.

Q. DOES A CAP ON THE SISC EXPOSE RATEPAYERS TO UNDUE RISK?

A. No. As stated in Duke witness Wheeler's testimony, the inclusion of a cap might result in some level of subsidization of QFs by general ratepayers if the average cost of integrating solar resources exceeds the cap.[23] However, the Public Staff believes that an important aspect of these proceedings is to ensure that the majority of costs imposed by intermittent solar QFs is recovered from intermittent solar QFs. The cap provides a reasonable balance between reducing uncertainty for QFs and refunding ratepayers for the costs of integrating intermittent QFs.

Q. DOES IMPOSING THE CAP WHILE ALLOWING THE REFRESH PROVIDE ANY BENEFITS TO RATEPAYERS OR QFs?

A. I believe so. As discussed in Section I of my testimony, several of the Public Staff's concerns with the Astrapé study, such as the load

---

[23] *See* Direct Testimony of Steven B. Wheeler at 7.

OFFICIAL COPY

Jul 29 2019

volatility data and the use of a variety of ancillary services, would be allayed with additional opportunities to improve the available data and the Astrapé model. For example, Duke may discover over the next several years that, due to the geographical diversity of new solar facilities, solar volatility is less than expected, resulting in a decreased SISC to the benefit of QFs. Future updates to the ancillary services study will improve the data and modeling used to determine the SISC, resulting in more accurate recovery of integration costs from QFs.

In addition, imposing the cap grants more certainty to QFs who are seeking interconnection to sell their energy and capacity at avoided cost rates. As the Commission summarized in its October 11, 2017, *Order Establishing Standard Rates and Contract Terms* in Docket No. E-100, Sub 148:

> [A] QF's legal right to long-term fixed rates under Section 210 of PURPA is addressed in FERC's J.D. Wind Orders. Order No. 69 establishes the appropriateness of a fixed QF contract price for energy and capacity at the outset of the QF's obligation because fixed prices are necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore, its financial feasibility before beginning the construction of a facility.[24]

[24] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 34, Docket No. E-100, Sub 148 (Oct. 11, 2017).

OFFICIAL COPY

Jul 29 2019

While the cap does not provide a single, fixed contract price for the duration of the PPA, it does provide the QF with reasonable certainty as to the maximum SISC charge it could be responsible for during the pendency of its obligation, limiting its potential exposure as it seeks financing.

III. DENC's Proposed Re-Dispatch Charge (RDC)

Q. WHAT IS DENC'S RDC?

A. DENC's RDC reflects the deviations from the optimal dispatch order of DENC's fleet of dispatchable generation units due to fluctuations in the output of intermittent, non-dispatchable resources. Similar to the changes in dispatch order caused by load uncertainty, the uncertainty of intermittent, non-dispatchable energy resources causes units to be dispatched out of the least cost dispatch order on an hour-to-hour basis, leading to increased fuel and purchased energy costs, which are passed on to ratepayers.

Q. HOW DOES DENC CALCULATE ITS RDC?

A. DENC utilizes a simulation analysis with a production cost model to determine the impact on total system costs under various levels of solar PV penetration, and calculates an average weighted re-dispatch cost over various scenarios and cost categories. DENC's analysis incorporates approximately 85 model runs and a differential

OFFICIAL COPY

Jul 29 2019

analysis between the results of each run to isolate the increase in costs associated with solar output fluctuations from the increase in costs associated with load fluctuations – both of which cause the incurrence of re-dispatch costs, but only one of which should be assigned to intermittent QFs.

The result of each differential analysis is an RDC for that specific scenario. DENC then averaged the RDCs of each scenario, choosing to assign equal weight to each combination of solar penetration and cost inclusion scenarios,[25] ultimately arriving at a RDC of $1.78/MWh, which it proposes to apply to any intermittent QF that signs a contract under its Sub 158 tariff. Unlike the methodology Duke employs to calculate its SISC, the DENC method is not probabilistic and does not measure system reliability.

Q. IS THE PROPOSED RDC A REASONABLE ATTEMPT TO QUANTIFY THE COSTS INCURRED BY INTERMITTENT GENERATORS?

A. Generally, yes, although we have identified concerns with the weightings applied to the various scenarios. In our reply comments, we suggest an alternate set of weightings that result in an RDC of

[25] Solar penetration scenarios consist of total solar capacity of: 80 MW, 2,000 MW, and 4,000 MW. Cost inclusion scenarios consist of: "all costs", "No PJM", "No Pumped Storage", and "generation costs only."

OFFICIAL COPY

Jul 29 2019

$0.78/MWh, which we believe is more reflective of the DENC system and actual costs incurred. Further, including cost scenarios such as the "No PJM" scenario[26] would inappropriately exclude the benefits provided by solar QFs due to DENC's membership in PJM.

Q. DO THE INTERVENORS IN THIS CASE SUPPORT DENC'S RDC?

A. Generally, no, for the same reasons they oppose Duke's SISC. SACE witness Kirby identifies similar concerns with scenario weightings as those identified by the Public Staff.[27]

Q. DOES DENC ACCEPT THE PUBLIC STAFF'S PROPOSED REVISIONS TO ITS RDC?

A. Yes. While DENC maintains that the weightings it originally assigned to each solar penetration and cost inclusion scenario were appropriate, it is willing to recalculate the RDC with the recommended weightings the Public Staff proposed in its reply comments.[28]

Q. IS THERE ANY OVERLAP BETWEEN DENC'S RDC AND DUKE'S SISC?

---

[26] The "No PJM" scenario reflects model runs in which DENC's system interacts with PJM, but the net revenue from market transactions is ignored.
[27] Initial Comments of SACE, Attachment C, at 1-2.
[28] *See* Reply Comments of the Public Staff at 21.

OFFICIAL COPY

Jul 29 2019

A. Yes. While the two charges attempt to quantify different aspects of integrating intermittent generation and use different approaches, both methods are based on the principle that increased costs are generally derived from higher fuel consumption due to each Utility's fleet operating outside of optimal ranges and out of optimal dispatch order. As such, there is likely some overlap in the increased costs the Utilities incur under the two approaches. Based on the review of the RDC and the SISC, I believe that the two charges are not mutually exclusive.

IV. <u>NCSEA and Public Staff's Proposals Related To Differing Ancillary Services Costs For Innovative QFs</u>

Q. AS IT RELATES TO ANCILLARY SERVICES, PLEASE DESCRIBE THE FINDINGS OF THE ASTRAPÉ STUDY.

A. The Astrapé model identified a need for additional ancillary services in order to respond to the intra-hour fluctuations of solar generation facilities interconnected to the grid.

Q. WHICH ANCILLARY SERVICES ARE IDENTIFIED BY THE MODEL?

A. As previously discussed, the Astrapé model used "load following up reserves," which are identified as a "60 minute product served by

OFFICIAL COPY

Jul 29 2019

units who have minimum load less than maximum load,"[29] to meet the intra-hourly fluctuations of solar output. While the model identified other types of ancillary services, only load following up reserves were added as solar penetration levels increased.

Q. **WHAT QUANTITY OF LOAD FOLLOWING UP RESERVES DID THE ASTRAPÉ STUDY IDENTIFY AS NECESSARY TO INTEGRATE SOLAR RESOURCES?**

A. For DEC, 26 MW of additional load following up reserves were required to integrate a total of 840 MW of solar. For DEP, 166 MW of additional load following up reserves were required to integrate a total of 2,950 MW of solar. These solar capacity totals reflect the Existing Plus Transition solar capacity for each of the utilities.

Q. **WHAT DO YOU MEAN BY 'ADDITIONAL' LOAD FOLLOWING UP RESERVES?**

A. Astrapé performed a model run without any solar on the grid, and due to load fluctuations and generator outages, the model required a certain amount of "baseline" ancillary services to reliably meet demand. In subsequent model runs, as Astrapé increased the amount of solar penetration, the reliability of the grid (as measured by the $LOLE_{FLEX}$ metric) decreased. In order to keep grid reliability

[29] Astrapé Ancillary Services Study at 43.

OFFICIAL COPY

Jul 29 2019

constant as additional intermittent solar is added, the amount of load following up reserves was increased. This increase represents the additional ancillary services that are attributable to the intermittency of solar generators on the grid.

It is the Public Staff's understanding that the Duke-owned generation fleet has sufficient available capacity currently to meet this additional ancillary services requirement, and that at this time there is no need for Duke to build additional generation facilities solely to provide this additional ancillary services requirement.

Q. DOES PURPA REQUIRE UTILITIES TO PURCHASE ANCILLARY SERVICES FROM QFs?

A. I am not a lawyer, but it is my understanding that PURPA generally requires a utility to purchase the energy and capacity output from a QF at the utility's avoided costs. PURPA does not, however, obligate the utility to purchase ancillary services from QFs.[30]

Q. COULD THE NEED FOR ANCILLARY SERVICES IDENTIFIED BY THE ASTRAPÉ MODEL BE SERVED BY THE IMPLEMENTATION OF AN ANCILLARY SERVICES MARKET IN NORTH CAROLINA?

[30] 18 CFR § 292.303(a), Electric Utility Obligations Under This Subpart.

OFFICIAL COPY

Jul 29 2019

A. Potentially, yes. In our reply comments, the Public Staff agreed with NCSEA witness Johnson's assertion that certain QFs have the technical ability to provide ancillary services, and we stated that, "a market or competitive solicitation for a limited quantity of ancillary services into which third party generators could bid has the potential to reduce costs to ratepayers and facilitate the cost-effective integration of intermittent resources."[31]

More importantly, the Astrapé study identified a methodology for Duke to quantify the "avoided cost" of ancillary services. This information could be useful in future proceedings and in negotiated contracts where technologically capable QFs might be compensated for ancillary services provided to the grid.

Q. ARE THERE ANY SPECIFIC CHALLENGES TO IMPLEMENTING A MARKET FOR ANCILLARY SERVICES IN NORTH CAROLINA?

A. Yes, there are several. First, Duke is not a member of an RTO, and as such, no organized competitive market for third-party services exists. In RTOs such as PJM, there is a specifically defined ancillary services market into which any generator may bid.

Second, as previously stated, PURPA does not require utilities to purchase ancillary services from QFs. With the responsibility for

[31] Reply Comments of the Public Staff at 23.

OFFICIAL COPY

Jul 29 2019

reliable grid operation falling on the utility, a market for such services would face significant regulatory challenges. For a QF to provide ancillary services for reliability, a responsibility borne solely by the utility, the utility may assert that it would need complete control over the QF's operations, raising complex questions of ownership and control in the traditional relationship between a utility and a QF under PURPA.

Finally, the additional ancillary services need identified by the Astrapé study is not large – a total of 192 MW in DEC and DEP combined to integrate the combined 3,790 MW of Existing Plus Transition solar. While this need will grow as solar penetration increases, the costs to conduct a competitive solicitation to procure this amount of ancillary services from third parties might exceed the savings actually realized.

Q. DOES THE PUBLIC STAFF AGREE WITH NCSEA THAT INNOVATIVE QFs MAY REDUCE THE NEED FOR ADDITIONAL ANCILLARY SERVICES IN A WAY THAT MAKES THE SISC UNNECESSARY?

A. Yes. The Public Staff believes that certain technologies, such as energy storage, could, if operated appropriately, reduce or eliminate the intermittency of the output from solar generators. To the extent a QF can materially demonstrate that it does not impose additional

OFFICIAL COPY

Jul 29 2019

ancillary service costs on the system, it should not be subject to the SISC or, to a lesser extent, the RDC.

Q. DO QFS NOT ELIGIBLE FOR THE STANDARD OFFER HAVE THE ABILITY TO MITIGATE THE SISC?

A. Yes. Section II.A of the SISC Stipulation specifically grants a QF that enters into a negotiated contract the ability to mitigate the SISC by demonstrating and contractually obligating itself to operate in a manner that materially reduces or eliminates the need for additional ancillary service requirements.

V. <u>Duke's Proposed Modifications to the Standard Terms and Conditions as related to the Energy Storage Protocol</u>

Q. PLEASE BRIEFLY SUMMARIZE THE ENERGY STORAGE PROTOCOL PROPOSED FOR QFs SELLING UNDER SCHEDULE PP.

A. The energy storage protocol provides a standardized set of operating instructions to QFs utilizing energy storage devices that wish to sell power under Duke's Schedule PP. Broadly, it includes provisions: (i) mandating the storage device be charged exclusively from the renewable energy resource; (ii) limiting the maximum output of the facility; (iii) limiting the ramp rate for the storage device and the combined ramp rate for the entire facility; (iv) prescribing time

OFFICIAL COPY

Jul 29 2019

windows, aligned with premium peak hours, during which the storage device can be discharged; (v) requiring that during discharge windows, the storage device discharge in such a way as to hold the total facility output constant; and (vi) permitting Duke the right to add or modify operating restrictions to the extent necessary to comply with NERC standards. The energy storage protocol for Schedule PP facilities is attached as Exhibit D.

Q. HOW DOES THE ENERGY STORAGE PROTOCOL PROPOSED IN THIS PROCEEDING DIFFER FROM THE ENERGY STORAGE PROTOCOL USED IN TRANCHE 1 OF THE COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY ("CPRE") PROGRAM?[32]

A. The terms of the energy storage protocol included as part of the Tranche 1 CPRE purchase power agreement ("PPA"), require the QF and Duke to communicate more frequently about the state of charge of the energy storage device and allowable bulk discharge windows for the QF. Duke's proposal in this proceeding has modified that communication requirement to require levelized total facility output during premium peak windows, reflecting that the Schedule

[32] Docket Nos. E-2, Sub 1159, and E-7, Sub 1156.

OFFICIAL COPY

Jul 29 2019

PP facilities will likely be smaller and more numerous than CPRE facilities.

In addition, the ramp rates have been modified. For example, the CPRE energy storage protocol restricted ramp rates for the storage resource to 5% of the facility's nameplate capacity per minute; in Schedule PP, the ramp rate for the storage resource is restricted to 10% of the storage resource's capacity per minute. As different facilities may have different energy storage to solar capacity ratios, it is difficult to determine if these changes constitute a more or less restrictive policy than that in the CPRE proceeding.[33] The energy storage protocol for Tranche 1 of the CPRE is attached as Exhibit E.

Q. DOES THE PUBLIC STAFF HAVE A POSITION AS TO WHETHER THE ENERGY STORAGE PROTOCOL PROPOSED FOR QFs SELLING UNDER SCHEDULE PP IS REASONABLE?

A. While the Public Staff does not have the expertise to determine whether or not the proposed energy storage protocol is reasonable, we recognize that some operational guidelines for facilities incorporating energy storage devices are appropriate to ensure that the facilities are operated in a safe, reliable, and efficient manner,

[33] In subsequent discovery (presented as Exhibit F), Duke has indicated that it chose the ramp rate constraints in an attempt to accommodate an industry standard of ramping to full output over a 10-minute period.

OFFICIAL COPY

Jul 29 2019

and that the criteria addressed in the Duke's proposed energy storage protocol are relevant factors in providing information to system operators on how the storage facilities would operate in parallel with the utilities system.

Due to the complexity of Duke's system and the need to consider the aggregate effect of potentially large quantities of third-party energy storage connected to the grid, we generally defer to Duke on how to best maintain system reliability. However, we understand that intervenors representing solar developers have raised concerns about the energy storage protocol, and support a technical conference or stakeholder proceeding to comprehensively address energy storage.

Q. **WILL LARGER QFs NOT ELIGIBLE FOR SCHEDULE PP BE SUBJECT TO THE SAME ENERGY STORAGE PROTOCOL IN THE FUTURE?**

A. At this time, Duke has only provided the energy storage protocol for facilities that commit to sell under its standard offer avoided cost tariffs. However, Section II.A of the SISC Stipulation specifically allows QFs that enter into negotiated contracts the ability to operate in a manner that reduces or eliminates the need for ancillary services, thereby reducing or waiving the SISC. It is likely that such operation would be substantially different than the manner of

OFFICIAL COPY

Jul 29 2019

operation allowed pursuant to the energy storage protocol proposed in this proceeding.[34]

Therefore, I do not believe it is not appropriate to enforce the standard energy storage protocol on a solar QF that is attempting to avail itself of the provisions of Section II.A of the SISC Stipulation; rather, such facilities should be given an opportunity to modify the energy storage protocol in such a way to obligate the facility to operate in a manner that materially reduces or eliminates the need for additional ancillary service requirements.

Q. WILL QFs WITH STORAGE PARTICIPATING IN FUTURE TRANCHES OF THE CPRE BE SUBJECT TO THE SAME ENERGY STORAGE PROTOCOL?

A. It is not clear. The Independent Administrator has submitted a list of "Storage Products and Attributes."[35] Most of these features of energy storage would be prohibited if the energy storage protocol proposed for Schedule PP were applied to CPRE projects. Further,

[34] For example, a solar QF that wishes to use an energy storage device to smooth its output profile and eliminate any unplanned fluctuations could be eligible to waive the SISC. However, such operation might require the energy storage device to discharge periodically throughout the day to compensate for intermittent cloud cover, which would violate the requirement for levelized output during premium peak hours. Ramp rate constraints contemplated in the proposed energy storage protocol might also be too restrictive to allow the battery to fully smooth the output profile in response to cloud cover.

[35] *See* "IA Stakeholder's Meeting Report" filed March 15, 2019, in Docket Nos. E-2, Sub 1159, and E-7, Sub 1156, Attachment A.

OFFICIAL COPY

Jul 29 2019

as the CPRE PPAs have 20-year terms, there is some concern that requiring CPRE projects with storage to exclusively charge from the renewable energy facility could unnecessarily restrict the ability of a solar plus storage facility to provide tangible and quantifiable grid benefits in the future. The CPRE stakeholders could not reach consensus on other areas of importance related to storage,[36] and this issue will likely be the subject of further discussion for future CPRE Tranches.

Q. DOES THE PUBLIC STAFF HAVE ANY SPECIFIC RECOMMENDATIONS FOR MODIFICATIONS TO THE ENERGY STORAGE PROTOCOL PROPOSED IN THIS PROCEEDING?

A. No. The Public Staff anticipates that other intervenors may submit specific concerns and proposed modifications to the energy storage protocol in their testimony, and will review and consider them as appropriate.

The Public Staff acknowledges that several stakeholders in the CPRE dockets have expressed concerns about the restrictions in the energy storage protocol. Although the protocol has been updated in this proceeding, we still anticipate that solar developers will see the proposed protocol as barrier to solar plus storage facilities. The

[36] *Id.* at 6-7.

OFFICIAL COPY

Jul 29 2019

Public Staff would like the concerns of the development community addressed in this Docket by both the Utilities and those intervenors who have experience operating renewable energy facilities coupled with energy storage. The Public Staff anticipates that, depending on the service the storage is providing, it may be appropriate to develop multiple protocols to address different services.[37]

VI. <u>The Stipulation Filed April 18, 2019, Related To Energy And Capacity Rate Design ("Rate Design Stipulation").</u>

Q. HOW DID THE PUBLIC STAFF AND DUKE REACH THE AGREEMENTS OUTLINED IN THE STIPULATION?

A. In its initial comments, the Public Staff requested additional granularity in the energy rate design beyond that proposed by Duke and DENC in their initial filings, and solicited feedback from intervenors and the Utilities on possible refinements. The Rate Design Stipulation represents the significant collaborative effort that went into reaching a compromise that met the Public Staff's basic core objective that, "to the extent possible, avoided energy costs should reflect each utility's actual avoided production cost."[38]

---

[37] Examples of potential energy storage services are presented in the "IA Responses to Technical Session Questions", filed May 31, 2019 in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156.

[38] Initial Comments of the Public Staff at 54.

OFFICIAL COPY

Jul 29 2019

The Public Staff believes the objective methodology presented as Attachment B of the Rate Design Stipulation will promote a more consistent approach to compensating solar facilities during the hours when energy is most needed in this proceeding and future biennial avoided cost proceedings.

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN THE RATE DESIGN STIPULATION AND DUKE'S ORIGINAL PROPOSED RATE DESIGN.

A. Broadly, the Rate Design Stipulation and Duke's original proposal both present similar improvements to the granularity of the on- and off-peak hours found in Duke's Option A and Option B rate designs approved in Sub 148. Both propose using load data to determine on- and off-peak energy hours, and both use Loss of Load Expectation ("LOLE") data based on the Astrapé Capacity Value of Solar study presented in Duke's 2018 IRPs[39] to determine capacity hours.

The Rate Design Stipulation largely incorporates the Public Staff's suggested additional granularity in energy hours. Specifically, the proposed rate design adds a shoulder season in a shift towards a three-season classification system; it also includes a "premium peak"

[39] 2018 Integrated Resource Plan and 2018 REPS Compliance Plan, filed by DEC and DEP in Docket No. E-100 Sub 157. (September 5, 2018).

OFFICIAL COPY

Jul 29 2019

designation, with energy rates higher than on-peak rates, for a limited number of hours where Duke's average marginal cost is in an upper percentile. Finally, it adopts a series of guidelines that should help Duke more objectively determine the appropriate rate design and seasonal classification of months in future avoided cost proceedings.

The Rate Design Stipulation is the result of significant give and take between Duke and the Public Staff, as both parties sought to balance the more administratively complex rate design proposed in the Public Staff's initial comments with the anticipated benefits to ratepayers from additional granularity.[40]

Q. DID THE PUBLIC STAFF SUGGEST ANY CHANGES TO THE RATE DESIGN FOR CAPACITY PAYMENTS?

A. The Public Staff largely agreed with Duke's proposed capacity payment hours and seasonal allocation for the reasons discussed in our initial comments,[41] and did not propose any significant changes to the capacity rate design. We believe that to prevent overpayment to QFs for capacity that is not needed, it is most appropriate to pay capacity payments only during hours where there is a loss of load risk.[42] As Duke's IRPs reflect winter planning, utility-owned capacity

[40] A more detailed discussion of the adjustments made by Duke and the Public Staff can be found in Duke Reply Comments at 70-73.

[41] Initial Comments of the Public Staff at 57.

[42] Loss of load risk was calculated on an hourly and monthly basis by Astrapé in its Capacity Value of Solar Study, filed in Docket No. E-100, Sub 157.

OFFICIAL COPY

Jul 29 2019

is only deferred when QFs can provide capacity during the winter hours when capacity is needed the most – specifically, the early morning hours.

The proposed use of the LOLE metric to determine the hours and seasons in which capacity is most needed is reasonable and protects ratepayers from overpaying for QF capacity. In addition, the proposed capacity rate design sends the appropriate price signals to QFs, providing price incentives to developers who design their facility to provide capacity when it is most valuable to the utility.

Q. WHY DO YOU BELIEVE THE RATE DESIGN STIPULATION IS IN THE BEST INTERESTS OF RATEPAYERS?

A. Generally, more granular avoided energy and capacity rates will send more accurate price signals to QFs. If there is enough of a differential between pricing in high value hours and low value hours (i.e., premium peak vs. off-peak hours), this differential may lead to developers investing in technology and energy generation facilities that best meet the needs of the electric grid.

The Public Staff believes the Rate Design Stipulation offers a rate design which pays QFs the highest rate for energy put on the grid when it is needed the most (such as early morning winter hours), and thus can bring ratepayers' and private developers' interests into

OFFICIAL COPY

Jul 29 2019

alignment. This Rate Design Stipulation would provide innovative QFs with a rate design granular enough so that they can identify the periods of system need and be properly compensated for contributing to meet that need.

Q. HAS THE PUBLIC STAFF INVESTIGATED THE POTENTIAL IMPACT OF THE RATE DESIGN STIPULATION ON RATEPAYERS?

A. Yes. An analysis of the original Sub 158 rates filed by Duke on November 1, 2018, and the proposed Rate Design Stipulation rates is presented below in Figure 1.

A comparison of the impact of as-filed rates and the Stipulation rates (hatched yellow bars) on the expected revenue[43] for a solar-only facility shows that the proposed changes in the Stipulation are effectively revenue-neutral; that is, a solar-only facility would be expected to earn approximately the same revenue under the original Sub 158 rate design proposed by Duke as it would under the rate design in the Rate Design Stipulation.[44] This "revenue neutrality" was an important element for the Public Staff, as the Public Staff did not want to propose changes that would provide additional

[43] The effect of a solar integration services charge is not included in this analysis.

[44] Adopting the Stipulation rate design would increase payments to a DEC solar-only facility by 1.7%, and decrease payments to a DEP solar-only facility by 0.4%.

OFFICIAL COPY

Jul 29 2019

compensation to a solar-only QF that did not modify its output to meet the needs of the grid.

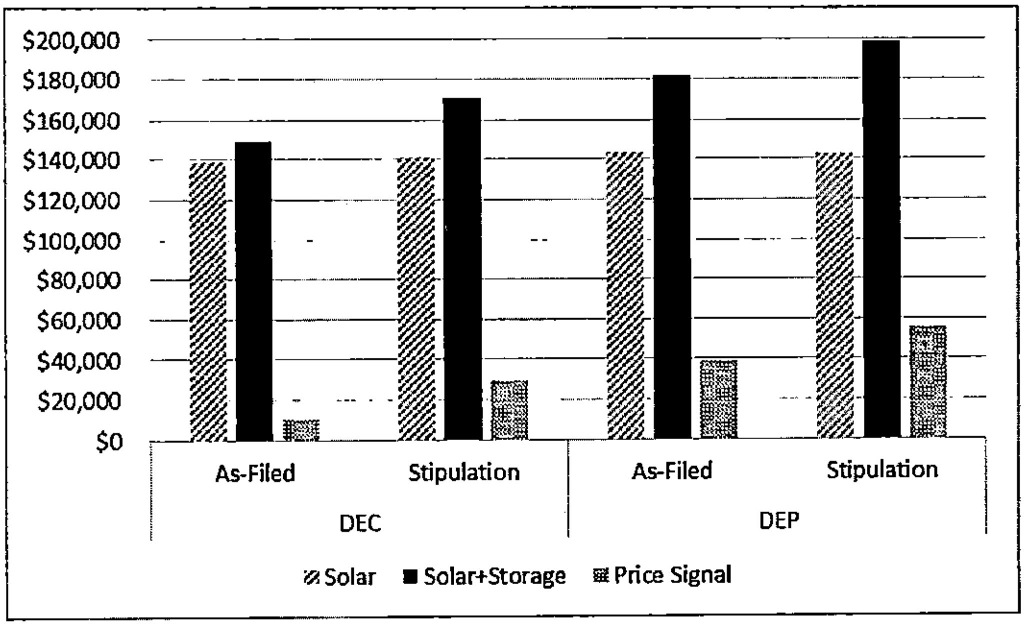
An estimate of the revenue that could be expected for a solar plus storage facility under the as-filed rates and the Stipulation rates is shown by the solid green bars of Figure 1. The difference between the solar and the solar plus storage revenue under the same rate design can be thought of as the "price signal" for the addition of storage[45] (displayed as a dotted blue bar) – it represents the increase in revenue that could be expected if a battery were added to the facility and dispatched in an optimal manner. By providing more granular rates that closely align with the actual avoided costs of the utility, the Stipulation has the effect of increasing this price signal by 185% in DEC and 45% in DEP.

[45] While the Public Staff discusses energy storage in this example, there are other modifications that could be made to a solar facility to better align with more granular energy rates, such as east or west facing panels, single or dual axis tracking, increased inverter loading ratio through over-paneling the facility, etc.

OFFICIAL COPY

Jul 29 2019

Figure 1: Comparison of first-year revenue for a 2 MW_{AC} solar QF without and with 1 MW/4MWh of battery storage. The "Price Signal" bar refers to the modeled increase in revenue associated with the addition and optimal operation of the battery storage device. Revenue includes energy and capacity payments.



In summary, compared to Duke's original proposed rate design, the Rate Design Stipulation provides rates that are revenue neutral to QFs that do not design their facilities to meet the more granular price signals, and provides stronger price incentives to QFs that produce more energy in the premium peak hours. It better aligns the utility's true avoided costs with the rates paid to QFs under PURPA, and restricts capacity payments to QFs only in hours where there is a loss of load risk, incentivizing QFs to provide capacity and energy at times when the system needs are greatest.

The Public Staff also believes that the methodology utilized to reach the Rate Design Stipulation could help streamline future avoided cost

OFFICIAL COPY

Jul 29 2019

proceedings by simplifying the energy and capacity rate designs proposed by the Utilities.

Q. HAS THE PUBLIC STAFF ENGAGED DENC OR OTHER INTERVENORS IN ITS DISCUSSION OF RATE DESIGN?

A. Yes. The Public Staff and DENC discussed similar modifications to its avoided cost rate design. DENC and the Public Staff have largely reached agreement on the details of a proposed rate design, and DENC indicated in its reply comments that it would be willing to accept the Public Staff's proposal, with certain modifications.[46] The Public Staff agrees with DENC's proposed modifications, which include: (i) the inclusion of September as a summer month; and (ii) the expansion of the premium peak hours to encompass four hours in the summer and four hours in the winter (two in the morning and two in the evening). The Public Staff notes that as modified, our proposal for DENC is nearly identical to the Duke Stipulation; however, we support the consideration of unique characteristics for individual Utilities in rate design.

In addition, the Public Staff reached out to NCSEA and NCCEBA to discuss the more granular rate design proposed in our initial comments. Although NCSEA and SACE generally supported the

[46] Reply Comments of DENC at 23-24.

OFFICIAL COPY

Jul 29 2019

concept of more granular rates in their reply comments, they declined to become parties to the Stipulation.

Q. ARE THERE ANY CHANGES TO COMMISSION RULES THAT WOULD AID IN ACCOMMODATING THE RATE DESIGN STIPULATION?

A. Yes. The avoided cost rate design proposed in the Rate Design Stipulation recommends changes to the on-peak and off-peak hours, adopts new "premium peak" hours, and presents guidelines for evaluating energy hours and seasons in future avoided cost proceedings that could result in gradual changes of premium peak, on-peak, and off-peak hours over time. Therefore, the Public Staff believes that it is appropriate for the Commission to consider two minor changes to Commission Rules R8-64 for applications for a Certificate of Public Convenience and Necessity ("CPCN") and R8-71 for the expedited review of CPCN applications for utility-owned projects selected by the CPRE Program.

Q. PLEASE DESCRIBE THE RELEVANT PARTS OF THE CURRENT RULES FOR WHICH YOU ARE REQUESTING MODIFICATIONS.

A. Commission Rule R8-64(b)(6)(iii)(a) requires, in part, that CPCN applications for solar PV facilities entering into a contract of five years or more and of a size greater than 25 MW include "[a] detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year."

For utility-owned renewable projects that successfully bid into the CPRE program, R8-71(k)(2)(iii)(6) similarly requires the "projected annual production of the renewable energy facility in kilowatt-hours, including a detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year."

Q. PLEASE DESCRIBE THE CHANGES YOU ARE REQUESTING.

A. The Public Staff suggests that these requirements be streamlined to request an hourly production profile from the applicant for one year, whether it be a QF or a utility-owned facility. The information requested in the existing rules originates from hourly production profile data created by readily available solar PV modeling software, but the data requires additional processing to meet the existing rules' requirements. Thus, our proposed change should reduce the administrative burden on applicants by eliminating the additional processing. In addition, the Public Staff believes that its review of CPCN applications would benefit from an understanding of the

OFFICIAL COPY
Jul 29 2019

OFFICIAL COPY

Jul 29 2019

production profile and factors which influence its shape, rather than simply monthly summaries.

A proposed revision to the rules is presented in Exhibit G.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

OFFICIAL COPY

Jul 29 2019

BY MS. CUMMINGS:

Q Mr. Thomas, did you prepare a summary of your testimony?

A I did.

Q Can you please share it at this time?

A Yes. The purpose of my testimony is to make recommendations to the Commission regarding the proposed avoided cost rates filed by DEC, DEP, and DENC. I address (1) Duke's quantification of ancillary services cost of integrating qualifying facilities, or QFs, solar; (2) Duke's proposed solar integration services charge, or SISC; (3) DENC's proposed re-dispatch charge, or RDC; (4) ancillary service costs for innovative QFs; (5) the energy storage protocol included in Duke's proposed Terms and Conditions; and (6) the Rate Design Stipulation filed April 18, 2019.

Duke's Quantification of Ancillary Services Cost and SISC Rate Design

My testimony reiterates the Public Staff's agreement with Duke's assertion that the integration of increasing amounts of intermittent QF generation has resulted in increased costs to ratepayers that are not currently captured in the calculation of avoided energy rates. Duke has attempted to quantify these costs by

OFFICIAL COPY
Jul 29 2019

hiring Astrapé Consulting to perform reliability-based probabilistic modeling of DEC's and DEP's system operations. In the current modeling, as solar penetration increases, reliability is held constant and the observed increase in system costs is distributed over all solar generation to calculate the SISC. My testimony describes these costs which are currently borne by ratepayers through the annual fuel rider adjustments and base rates. As a ratepayer advocate, my testimony emphasizes that the recovery of solar QF integration costs from the cost causers, solar QFs, is appropriate and not unprecedented. I also discuss some of the related technical issues that the Public Staff identified with the Astrapé study in our initial and reply comments.

While quantifying solar integration costs is a complex challenge, I believe that the Astrapé study provides a reasonable framework to do so. I identify concerns with the proposed biennial refresh of the SISC, namely, that QFs would face uncertainty as to their future costs, similar to that contemplated by the Commission in the 2016 avoided cost proceeding. The Stipulation of Partial Settlement, or SISC Stipulation, filed May 21, 2019, accomplishes several goals that appropriately balance the interests of ratepayers with

OFFICIAL COPY

Jul 29 2019

the rights of QFs under PURPA. The SISC Stipulation: (1) acknowledges the SISC as a reasonable method to recover integration costs from solar QFs; (2) enables QFs that can design and operate their facilities in a way that does not increase costs to ratepayers by materially reducing the ancillary services required to integrate their facilities to avoid the SISC; and (3) uses an established methodology to set a cap on the SISC to reduce uncertainty faced by QFs.

DENC's RDC

My testimony also discusses the purpose of the RDC proposed by DENC and finds that it is a reasonable approach to collect costs caused by intermittent generation from QFs. I also state my understanding that even though the RDC and Duke's SISC are calculated using different methodologies, some overlap is likely between the costs quantified by each charge. In addition, the Public Staff's review of the proposed RDC led us to recommend that the RDC be reduced significantly, based upon the scenario weights applied to DENC's differential analysis. DENC stated its willingness to accept our recommendations regarding the scenario weighting, as well as our proposed RDC recalculation of $0.78 per MWh.

Innovative QFs

OFFICIAL COPY

Jul 29 2019

My testimony also addresses the potential for innovative QFs to provide ancillary services to the grid and to receive compensation for these services. I propose that the Astrapé study could also be used to quantify the avoided cost of certain ancillary services. While I generally agree with the concept that some QFs are technically capable of providing ancillary services to the grid, I identify several logistical, economic, and regulatory challenges to this approach. While I do not support the creation of an ancillary services market at this time, I do believe that innovative QFs have the ability, under Section II.A of the SISC Stipulation, to reduce or eliminate the SISC by operating in a certain manner.

Energy Storage Protocol for Standard Offer QFs

My testimony addresses the inclusion of an energy storage protocol in Duke's proposed Terms and Conditions, which is itself a modified version of a similar protocol used in Tranche 1 of the Competitive Procurement of Renewable Energy, or CPRE program. I also briefly address the potential conflict between the energy storage protocol proposed by Duke and the ability of a QF to avail itself of the provisions of Section II.A of the SISC Stipulation in an attempt to reduce or eliminate the

OFFICIAL COPY

Jul 29 2019

applicability of the SISC.

Rate Design Stipulation

My testimony briefly summarizes the agreement reached between Duke and the Public Staff regarding rate designs for avoided energy and capacity payments. The stipulated rate design attempts to move to more granular rates that will compensate QFs for -- for providing energy during periods of high demand and for providing capacity when the Utility faces loss of load risk. I believe that the Stipulation will serve to align the interests of both ratepayers and developers, as it will send more accurate price signals and may incent QFs to be designed and operated in a way that best meets the needs of the electric grid. My testimony also addresses DENC's in-principle agreement with the Public Staff on rate design.

Finally, my testimony proposes specific changes to Commission Rules R8-64 and R8-71 to aid in accommodating the proposed rate design.

This concludes my testimony.

MS. CUMMINGS: Thank you, Mr. Thomas. And one piece of housekeeping, if the Public Staff could move to have the initial -- our Initial and Reply Comments moved into the record as well.

OFFICIAL COPY

Jul 29 2019

CHAIR MITCHELL: Hearing no objection, the motion is allowed.

(Whereupon, the Initial Statement of the Public Staff and the Reply Comments of the Public Staff were admitted into evidence. The confidential versions were filed under seal.)

MS. CUMMINGS: Thank you. Our witnesses are available for cross examination.

CHAIR MITCHELL: Thank you. Mr. Levitas.

MR. LEVITAS: Good afternoon, gentlemen. Excuse me. I'm Steve Levitas, counsel for NCCEBA. Nice to be with you this afternoon. I believe most, if not all, of my questions will be addressed to Mr. Thomas as they primarily concern the integration charge.

And let me say at the outset that we, on the Intervenor side, appreciate the effort that the Public Staff has made to try to improve the charge, as originally proposed by Duke and Astrapé, and to work to include some -- some safeguards in the implementation of that charge. As you know from the testimony you've heard over the last several days, we don't think you've gotten it quite right, but I did want to express my appreciation for the work that you've done to date.

OFFICIAL COPY

Jul 29 2019

CROSS EXAMINATION BY MR. LEVITAS:

Q So Mr. Thomas, if I can begin, let me ask you, do you consider yourself to be an expert on the subject of the integration of intermittent resources into electrical grids?

MR. DODGE: Madam Chair, I'd -- I'd like to object just right from the start on this question. I think Mr. Thomas' testimony speaks for itself, and his statement of qualifications is included. His testimony is designed to respond to the specific questions the Commission asked the Public Staff to file testimony on and represents the position of the Public Staff in response to those matters.

MR. LEVITAS: And if I may, I'm not -- certainly not seeking to exclude Mr. Thomas' testimony, but to inquire as to its probative value. We have in this case a very significant disagreement between experts, and I want to understand the extent to which Mr. Thomas is able to act as a peer reviewer of the work of those experts on this subject.

CHAIR MITCHELL: Mr. Levitas, I'm going to sustain the objection. We understand Mr. -- we understand his -- his background and his credentials, so please move forward with another line of questioning.

OFFICIAL COPY

Jul 29 2019

MR. LEVITAS: All right.

Q Well, let me turn, then, Mr. Thomas, to some process issues. I believe at page 8 of your testimony you indicate that -- that you had -- had numerous phone calls with representatives of Duke and Astrapé concerning the integration study; is that correct?

A (Thomas) Yes. We had phone calls and in-person meetings to discuss the details of the model and the study results.

Q And were Intervenors or any of their technical experts included in any of those meetings?

A I know that the Public Staff did reach out to Intervenors to discuss their concerns with the integration study and that we did review their testimony, but the Intervenors were not on every one of these calls with Duke Energy.

Q Do you -- do you think it's best practice in a matter of this sort to try to get all of the stakeholders in one room and to see if you can reach consensus among the -- the various parties?

A I think for the purposes of this proceeding we were trying to analyze the integration cost proposed by Duke, and I believe that we took the stakeholders' and all Intervenors' points of view under consideration in

OFFICIAL COPY

Jul 29 2019

the Initial and Reply Comments and -- as well as the supplemental testimony, so I -- I believe we considered all Intervenors' points of view when we were discussing this charge.

Q Well, I do want to clarify, without regard to your qualifications, just an understanding of your role in this matter. In your -- in your summary you described yourself as a ratepayer advocate, correct? That's the role of you and the Public Staff?

A That is correct.

Q So it -- it -- it's not your role to serve as a neutral arbiter or decision maker in resolving disputes between competing points of view, is it?

MR. DODGE: Madam Chair, I'd -- I'd like to repeat the objection I made earlier. Mr. Thomas is testifying, presenting the testimony of the Public Staff on the -- the five items that were identified in the Commission's Order and listed in his summary. I think -- I think he's provided -- I think the testimony itself, if Mr. Thomas is allowed to talk about the substance of it, will be helpful for the Commission, and the Commission can weigh the sufficiency or the credibility of his testimony at that time.

MR. LEVITAS: Well, again, it's a little bit

OFFICIAL COPY
Jul 29 2019

different question to clarify the role of the Public Staff in this matter and, you know, we -- we have suggested that this process would have benefited from a neutral independent peer review of the competing points of view, and I just want to make clear that that has not been provided by the Public Staff.

CHAIR MITCHELL: Mr. Levitas, the Commission understands that the Public Staff represents the Using and Consuming Public pursuant to Chapter 62, so we're going -- I'm going to sustain the objection and -- and leave it at that. Thank you.

MR. LEVITAS: Okay. Thank you very much.

Q Mr. Thomas, I believe at page 6 of your testimony you indicated that in conducting your review of the Astrapé study and comments -- I'm just going to quote here in the middle of the page -- it says "The Public Staff also supported the analysis of SACE Witness Kirby of the reliability standards imposed on the model." Is that correct?

A Yes. That is what -- that is an accurate summary of the testimony.

Q And you go on to say and identifying at page 7 the -- the concerns that you had based on the analysis of the Kirby -- based on your review of the Kirby analysis,

OFFICIAL COPY

Jul 29 2019

that the concern that that raised, as you've heard from Mr. Kirby in these proceedings, is -- went to the reliability standard or metric that was applied and whether it was too stringent, correct?

A Upon reviewing Mr. Kirby's affidavit and the comments filed by SACE, we had originally supported that concern, as I identify and discuss in my testimony, but upon further review of both the Idaho study that Mr. Kirby relied heavily upon to make the comparison and working and understanding the Astrapé model at -- at a more deeper level, we decided that those concerns were no longer legitimate.

Q So could you be more specific? I mean, as we've heard up here over the last day and a half, the -- the principal issue or certainly one of the principal issues in dispute regarding the -- the accuracy and validity of the integration charges goes to whether the -- the study calls for an excessive measure of -- of imbalance events or holds that to -- holds -- establishes too -- too stringent a standard, so my -- my question is what exactly caused you -- if you could be more specific, what caused you to conclude that the LOLE FLEX Metric of 0.1 utilized by Astrapé is not overly stringent?

A So to begin the review of the Astrap--- of the

OFFICIAL COPY

Jul 29 2019

Astrapé study results, I -- as part of the task force of Public Staff that reviewed this filing, we looked at several other integration studies in different jurisdictions and generally reviewed these studies to see how they align with the Astrapé study in certain factors such as treating the DEC and DEP as load islands, and how they modeled uncertainty and variability, and also what the results were. And -- and when we're talking about results, I'm mostly interested in what is the number of additional ancillary reserves required to integrate a certain capacity of -- of intermittent generation.

And -- and what I found was that upon on my review of studies, which I did include the Idaho solar study that's been much discussed in this testimony, that the amount of additional reserves that Duke quantified was well in line with the results of the other studies that I had reviewed. So that was kind of where we began, and -- and that was before going more in depth into reviewing the LOLE study or -- I'm sorry -- the Idaho study to determine that the comparison Mr. Kirby was making between the 99 percent metric using the Idaho study and the .01 LOLE FLEX metric using Astrapé study are simply not comparable due to the different methodologies that each study used to arrive at very

OFFICIAL COPY

Jul 29 2019

similar conclusions.

Q Let me just ask you one more question in this vein. Do you have any basis for determining the correlation, to use Commissioner Clodfelter's term, between the -- the achievement of the metric in the Astrapé study and compliance with the NERC balancing standards?

A We did. Upon investigation of the SISC charge, we did ask Duke to provide some comparison of historical balancing reserves, and -- and we compared those to the balancing reserves that were predicted by the Astrapé model, and -- and I believe it's Exhibit C of my -- let me flip to it here real quick -- I believe Exhibit C of my testimony provides that summer at the top there where 1,663 MW were on the actual Duke system compared to 1,600 MW that were predicted by the model, and to my -- to the best of my knowledge, Duke met all NERC -- had no NERC violations in the year 2015, subject to check.

Q Understood, but, again, the -- the question is whether that may have been sufficient, but whether it was necessary. And just looking at your Exhibit C, the fact that -- that relaxing the metric produces somewhere between, I think, a 3 and 12 percent increase in the required reserves doesn't really tell you anything about

OFFICIAL COPY

Jul 29 2019

how --

MR. DODGE: Objection, Madam Chair. Is there a question?

MR. LEVITAS: Can I finish the question? Can I finish the question?

Q -- it doesn't really tell you anything about how that correlates with actual compliance with the NERC standards, does it?

A (Metz) Well, I think one thing that's been extensively discussed in here of how the 0.1 LOLE FLEX is not a NERC requirement, standard, or balance. I think as Commissioner Clodfelter very well noted, that the NERC standards are an absolute. The 0.1 LOLE FLEX is not that absolute factor being modeled.

A (Thomas) And if I can just add to Witness Metz, so the point of engineering models is not to perfectly simulate reality. And my experience with energy models is that any metric that you use is going to approximate reality, and the best you can do is to check that model's results against historical results and -- and see if you align, and if you align, great; if not, you need to make some changes to the model. So while LOLE FLEX is not comparable, you can't point out an LOLE FLEX violation and -- and say that that constitutes a NERC violation,

OFFICIAL COPY

Jul 29 2019

using the LOLE FLEX as a reliability metric to model DEC and DEP's system and then calibrating the actual reserves quantified to known reserves that are historically proven that did not result in NERC violations tells me that the -- tells me that the model is -- is adequately calibrated.

As I point out in my testimony, there's always room for improvement with models, and we hope that in future years as Duke refines its inputs and refines the -- any modeling techniques and input data, that this will become more accurate, but for the purposes of this proceeding we've found it to be a reasonable quantification of the charge.

Q All right. Let me move on to some other areas. I want to talk about the -- the cap that you have agreed to as part of the Stipulation. And as I understand the way that that works, you've got a -- the affected facilities are paying an average value, which starts at $1.10 in the case of DEC and -- and 2.39 in the case of DEP, correct?

A That is correct.

Q And -- and on a biennial basis, those facilities will be under this proposal subject to an upward adjustment of that amount based on recalculated

OFFICIAL COPY

Jul 29 2019

charges, correct?
A The --
Q Subject to the cap.
A The adjustment is -- is not predetermined. The adjustment could go down as the system becomes more flexible, or if gas prices fall, or if variability is found to be less than originally anticipated, or the cost could go up. But the point is, is the update is intended to refine the charge, not simply to increase it.
Q No. I understand that. I appreciate that. But let's -- let's take the example of a new QF facility that contracts in Year 1, this year. So in the case of that facility, it would -- and -- and it being a new, let's say, nonstandard offer QF, it would have a five-year --
A Right.
Q -- PPA term, correct? So under the proposal it would begin with -- and let's take the DEC example -- with a charge of $1.10 per MWh, and if I understand it correctly, two years into the agreement it would face the possibility of an upward adjustment, correct?
A It would face a revision to the charge, yes.
Q Right. But -- which includes a possibility of an upward adjustment. But --

OFFICIAL COPY

Jul 29 2019

A (Metz) But to add to that, I mean, it's a possibility it can go down as well.

Q I understand that. I'm just asking if there's a possibility it can go up.

A Right. As we're dealing with absolutes --

Q Yeah, yeah.

A -- I think it's --

Q Right.

A -- important to note that there --

Q Sure.

A -- can be ups or downs --

Q Sure. Fair enough.

A -- and we're not painting a picture in one direction.

Q Understood. So correct me if I'm wrong, but my understanding is that that -- whether it goes up or down, that new charge two years into the five-year contract will also be the recal--- it will be the recalculated average charge at that point in time, correct?

A (Thomas) Yes, it would.

Q All right. So in a five-year contract, more -- I think I'm more or less correct that there's only going to be one adjustment. So there's a rate at Year 1, it's adjusted at Year 3, Year 5 the contract is over. So

OFFICIAL COPY

Jul 29 2019

there will be one -- a one-time adjustment based on the then applicable average integration charge, correct?

A Yes.

Q So that being the case, what is the basis for utilizing a cap that is based on the incremental charge of the last 100 MW block in that two-year period, given that that is not the charge that would apply -- that would apply to that -- to any QF? It would still be charged the average.

A Sure. So just as a little bit of background, in our initial comments, when we were looking at the biennial update we proposed two different solutions. One was to charge the average and impose a cap, and the other was to simply charge each vintage of QF, subject to the 158 or the next avoided cost rates, to the incremental charge for that vintage, that block of -- of solar. That charge would be higher than the average. So we ended up with Duke, working with them to calculate a cap and -- and decided that that would be -- it would be easier to charge that -- that average cost to all QFs than impose a cap specific to the vintage.

Now, the calculation of the vintage was we tried to -- to decide, okay, so this block of solar, this vintage of solar being added under the 158 rates, from

OFFICIAL COPY

Jul 29 2019

the IRP we can determine that there's an approximate quantity of solar that -- that would be added under that 158. And so we said what is the highest cost that this block of solar could be directly responsible for? And that is the -- the incremental cost of -- of that block. And we looked at that last 100 MW because, first, that 100 MW block is similar to the 100 MW block that's used to calculate the avoided energy rates, and also just simple mathematics as you -- in order to separate the average from the incremental cost, you have to have separate blocks. As you can see from the results of the study, the first block of solar, the average and the incremental costs are the same.

So we determined that the QF that connects under the 158 rates should only be responsible up to the maximum incremental charge that would be associated with that vintage, and we -- we decided that would be an appropriate cap.

Q Well, I understand that -- that was your decision, Mr. Thomas, but the point that I'm getting at is that the -- the value of the cap is a value that the QF would never be charged because they're going to be charged, by your own admission, an average rate, not an incremental rate, correct?

OFFICIAL COPY
Jul 29 2019

A (Metz) Well, to put it in context, maybe the first question you asked of whether a negotiated contract would only have a refresh of one, that may be -- a one refresh period, that may be true, but, however, as we were solving here not only for negotiated contracts, but also a standard offer contract that was good for 10 years, so it would have multiple refreshes.

And we're also trying to look ahead at whether or not this charge -- and how it will be implemented through the CPRE process, so then we start talking about a 20-year term, so, therefore, we're solving for multiple time periods.

Q Well, I understand that, and that kind of leads to another question I have, which it appears to be the case that you're setting the cap at the same value for a five-year contract, a 10-year contract, and a 20-year contract, and that seems problematic on its face.

MR. DODGE: Objection. Is there a question?

MR. LEVITAS: Yeah.

Q Would you agree that -- that that is not equitable treatment of facilities, to -- to impose the same cap, apply the same cap to facilities with different contract lengths?

A (Thomas) I do not -- I do not agree that it is

OFFICIAL COPY

Jul 29 2019

inequitable to apply the same cap to all generators of a certain avoided cost vintage.

Q I'm sorry. My --

A (Metz) I mean -- I mean, add on to that, because it's looking at the average and the incremental component, so it's at a point where we look at existing plus transition. That is that group of -- that amount of solar that's identified through the IRP that we think is going to be incorporated within that time period.

Q Is it -- did I misunderstand you? I thought you said that the same cap -- if this Commission adopts what you're proposing, the same cap would be in place with respect to all contracts executed in the next two -- two years, whether they are five-year contracts, 10-year contracts, or 20-year contracts; is that correct?

A (Thomas) I can only speak in this cap to the stipulated -- to the negotiated and the standard offer contracts. The cap here is explicitly laid out for those contracts that apply for the Sub 158 vintage. While my testimony discussed that I believe the SISC should be considered in the CPRE proceedings with those 20-year contracts, it has not yet been determined how the SISC will be considered or how the cap will be applied, so --

Q Well, I'll ask you some further questions about

OFFICIAL COPY

Jul 29 2019

CPRE, but let me go back to my question about the new nonstandard offer PPA. And my -- my question is, how is it the case that a cap -- well, let me strike that for a second. Would you agree that the cap, as proposed in the Stipulation for both DEC and DEP, is, roughly speaking, two and a half to three times the initial average charge?

A The cap in DEC is 3.22 a MW and the cap in DEP is 6.70 a MW.

Q. And isn't that roughly two and a half to three times --

A I believe it's about that, yes.

Q Okay. And so my -- my question is, do you have any basis for believing that the average charge applicable to QFs under this approach indicate over a -- over a two-year period is going to go up threefold because that -- that's the impact of having this cap? Do you have any reason to believe that when this one adjustment is made in a five-year contract, that it's going to be a threefold increase in the average charge? Do you have any reason to believe that?

A I am -- I -- all I know is that the Astrapé model will be updated every two years. I know that the charges will reflect the average cost of the solar that's being studied on the system. Whether it goes up or --

OFFICIAL COPY

Jul 29 2019

that much in that time period, that was not the determining factor that we used in -- in deciding on the cap. We first decided how much solar should be studied in the Astrapé model, what made sense under the -- just a -- a logical approach, and then we used that amount of solar to calculate the cap. So we didn't start with a number and then work backwards from there. We started with a -- a target solar quantity and then used that to calculate the cap.

Q Well --

A (Metz) May I? Then there's another component of this, is not only are we talking about just the negotiated contract, say, new negotiated contract, but we're also looking at older contracts that are falling off and going into renegotiation. Again, it is -- part of SISC is to phase in these elements over a multiple time period, so they could be coming in at different update periods.

Q I understand that. The -- the question that I have is do you recognize that if the cap is set too high relative to an accurate assessment of how that charge may increase, that that has the potential to deter the formation of new contracts because they will become more -- less remunerative to the QF if the -- if the QF has to

OFFICIAL COPY

Jul 29 2019

account for a cap that is set at an excessive level?

A (Thomas) I'm sorry. Can you -- can you just repeat that question?

Q Sure. So I'm suggesting with this line of questioning that I think you've set the cap too high, at least with respect to a five-year contract, and what I'm asking you is do you understand that a QF, whether it's a renewing QF or a new QF, when it's making a decision whether it has a financially viable project, will have to account for the potential exposure to pay a charge up to that cap? So if you set the cap too high relative to what would actually be expected, you have the potential to deter QF development.

MR. DODGE: Objection. I think that's going beyond the -- the scope of what Mr. Thomas and our Panel has testified on here with regard to the QF financing. They're -- they're not experts on QF financing, and I believe your -- exceeds the scope of his testimony.

MR. LEVITAS: Well, I -- I'm not asking about the details of QF financing. I'm asking this question because I want to know whether the -- the Staff has adequately considered the -- both the accuracy of this cap and the potential for an inaccurate cap to deter QF development.

OFFICIAL COPY

Jul 29 2019

CHAIR MITCHELL: Mr. Thomas, I'm going to -- I'm going to overrule the objection. Again, we understand Mr. Thomas' credentials and qualifications, so please answer the question.

A So like I said, I cannot speak to the ability of QFs to -- to obtain financing with or without the cap, but there is a certain amount of risk in any business transaction, and I don't believe that the purpose of the PURPA rates is to remove all risk from a financial transaction. So to be clear, the -- the original proposal had no cap, which we identified and I think appropriately as violation of the rights of QFs under PURPA, so to establish that cap we approached it from what we believe to be a reasonable methodology, to use the Astrapé model to calculate that, and to the extent that this causes some risk to a QF, that is prob--- that is most likely true, but I -- I don't know what that will do to financing, the ability of it to be financed. But like I said, there's -- there's very little that is risk free.

Q Well, I appreciate that, and my goal is not to eliminate all risk; it's simply to be sure that the cap accurately reflects reality so that we don't have the unintended consequence of deterring QF development

OFFICIAL COPY

Jul 29 2019

inappropriately.

Let me move on to -- and let's talk about CPRE. I'm -- I want to start by trying to understand how the -- how the charge will work in the case of CPRE projects. So as an initial matter, is it your expectation that the -- the charge would be paid by the market participant or by the ratepayers directly?

A At -- at this time my testimony has simply stated that the SISC is -- is a component of avoided cost, and I believe the language of HB 589 caps the Utility's procurement obligation at the then determined avoided cost. So the CPRE Tranche 2 certainly needs to, pending Commission action on this SISC and -- and the rates and Tranche 2, we believe that if the SISC is approved, that the CPRE Tranche 2 should consider the SISC.

That can be implemented in a number of ways, which would require discussions with market participants, with the Utility, and particularly with the Independent Administrator.

Q Well, let me -- I want to, I think, correct or ask if -- if you want to correct something that you just said, because you described the -- the charge as a component of avoided cost, and I believe the Public Staff

OFFICIAL COPY

Jul 29 2019

has gone to great lengths in its testimony and negotiations with the parties to make clear that the integration charge is a separate charge that would be paid by the QF and it is not a decrement to avoided cost; isn't that right?

A Can -- can you just point me to the aspect of my testimony or comments that refers to that, because my understanding is different than yours.

Q Well, maybe some -- one of my colleagues can help me find the exact language, but the point that I'm referring to, maybe it will refresh your recollection, is that Duke and Dominion proposed different approaches in that Duke had clearly, throughout all -- all of the testimony and conversation, is proposing a charge, an incremental charge that doesn't change the avoided cost rate, but is a line item that is a charge paid by the QF that -- that reduces its net revenues because it's offset against avoided cost. Dominion initially proposed to do it the other way and roll its charge into avoided cost and would thereby reduce the avoided cost rate. Public Staff, I think correctly, disagreed with that and encouraged Dominion to conform to the Duke approach, and I believe they have agreed to do so.

A Yeah. So I -- I think we're talking here about

OFFICIAL COPY

Jul 29 2019

starting on page 29 through 32 on my -- on the Public Staff's initial comments, and you're partially correct in a summary of -- of what our statement there is. We had objected to including the SISC as a component of the avoided energy rate. We supported the SISC as a component of the avoided cost for solar facilities, but that would mean that it would be a separate avoided energy, separate avoided capacity, and a separate solar integration services charge.

What we had objected to was to folding that SISC into the avoided energy charge, for the reasons that we discussed in our -- our comments.

Q But, I mean, just to be clear, avoided costs are a value paid as a purchase price to the QF or to the market -- not to the market participant, but to QFs -- or other market participants have contract prices. What we're talking about here is a charge, not a payment, so it's -- it accomplishes at one level the same thing because it reduces the value to the -- to the seller, but as I'll elucidate a minute, it makes a difference which way you treat it. So you would agree with that, right?

A I -- I'm not sure I would agree with that statement. What -- what we stated there is that PURPA allows for the inclusion of certain charges, decrements,

OFFICIAL COPY Jul 29 2019

and -- and increments to the avoided cost that follow a variety of principles that have been outlined in the CFR.

So as to the avoided energy and the avoided capacity components, those are calculated using ProSim and the avoided -- the peaker methodology, but the avoided cost comprises all of these things, avoided energy, avoided capacity, and -- and avoided cost can take -- consider charges that are specific to the characteristics of the QF power. So it is -- once again, the SISC is a component of avoided cost separate from avoided energy.

Q Well, I apologize. That's not the way I understood either your testimony or Duke's testimony, but let me ask this question in the context of CPRE. As you know, bid award prices in CPRE by legislation are capped at the avoided cost rate, correct?

A That is -- that is the current administratively determined avoided cost, yes.

Q And so is a way that you envision this working that -- is that the avoided cost rate, for the purposes of CPRE, is going to be the avoided cost as otherwise calculated by the Commission minus the integration charge, and that's going to become the cap?

A Well, as I stated before, the -- how the SISC

OFFICIAL COPY

Jul 29 2019

is considered in Tranche 2 of the CPRE is entirely dependent upon the decisions made by the Commission and the collaboration between market participants, Utilities, and the IA. I think, from the Public Staff's perspective, it is important that the SISC be equally applied to third-party participants in the CPRE and Utility self-build proposal. So I think that is -- that is what we will strive, when we engage in these stakeholder negotiations in Tranche 2, to make sure that Utility builds and third-party builds are evaluated against the SISC on an equal footing.

Q Well, I understand that there's work to be done to figure this out and -- and has to get done in short order, but I would submit to you that there is a lot of variability in how this may play out, and it goes to the same issue that I was talking about, and so let me just ask you a question about this. Do you have a concern that there's a potential for CPRE bidders to have to make an assumption about what the future integration charge will be and incorporate and address that in their bids?

MR. DODGE: Madam Chair, again, I -- repeating the objection I made earlier about experts on speculating on what a QF may have to consider. I -- I think it's in appropriate to ask Mr. Thomas whether he has concerns

OFFICIAL COPY
Jul 29 2019

about what -- what -- they're going to have to factor in risk, so I think it's beyond the scope of his testimony, again, in this proceeding.

MR. LEVITAS: I'll just ask one more question on this, if I may.

CHAIR MITCHELL: Okay.

Q Isn't it the case, Mr. Thomas, that if the cap is set too high in -- let me strike that. Isn't it the case that a CPRE bidder will have to make an assumption about the integration charge to which it will be subject and include that in its bid, and that if that assumption is incorrectly high, that bids will come in and they may be below the cap in order for the award to occur, but the bids are going to be higher than they otherwise would be and the ratepayers are going to have to, therefore, pay a higher charge than they should otherwise have to pay? Isn't that right?

A As I said before, I -- I don't -- we don't know yet how the SISC will be implemented in the -- in the CPRE. You know, I think from our perspective, we -- obviously, we have concerns about 20-year contracts with uncontrolled solar generators that would be exempt from the charge, but at the same time we do want it to be considered, but the details have yet to be worked out.

OFFICIAL COPY

Jul 29 2019

So whether the -- the CPRE participant has to factor in some risk and -- and pay the SISC or whether the SISC is used to reduce the -- the cap that's applicable to the bids, you know, that's -- that's simply not clear, and there may even be other options on how to implement the charge in the evaluation of solar projects.

So I really can't speak to the assumptions that a QF might have to make bidding into Tranche 2 because there is so much uncertainty in how that charge will be considered or if it will be approved by the Commission at all.

Q Fair enough. You would agree, though, would you not, that if the structure of the integration charge and the cap were such that it caused bidders to inflate their bids relative to the actual integration cost, that would be a bad outcome for ratepayers?

A Getting into some speculation here, I suppose, but, I mean, our stance on -- on this would probably be similar to how our stance was on -- in system upgrade cost. Obviously, we -- we want the best outcome for ratepayers, and when it comes time to implement an SISC into any future tranche of the CPRE, we're going to try to advocate for the position that best protects the ratepayers and recovers those costs from QFs at the cost

OFFICIAL COPY

Jul 29 2019

causer --

Q And -- and the Commission just recently concluded, did it not, that ratepayers would be better served by having the network upgrade costs paid directly rather than it being incorporated into CPRE bids; isn't that right?

A I believe that they did decline to include a bid refresh in Tranche 2.

Q Let me just quickly ask you some similar questions about GSA. We asked Duke witnesses about this. Has the Public Staff formed a position as to whether the integration charge should be applicable to GSA projects?

A At this time we don't have a position on that and -- and how that charge might be applied. We haven't spoken internally about it.

Q Is -- is it accurate to say that in the year and a half that the GSA proceeding has been ongoing, that there has not been any public discussion and any filings about the potential application of this charge to GSA projects?

MR. DODGE: I'd like to object again. I think when Mr. Levitas was asking questions about GSA of other witnesses, again, it's beyond the scope of this proceeding, what the witnesses have been asked to testify

OFFICIAL COPY

Jul 29 2019

on, so at this point Mr. Thomas is not providing testimony on the applicability of this to CPRE or the GSA context. It's for the purposes of the avoided cost proceeding.

CHAIR MITCHELL: Sustained.

Q Just one final question or two, Mr. Thomas. I believe the -- well, Public Staff has taken the position, we appreciate this, that the -- the charge should not be applicable to solar facilities that include properly designed and operated storage that would reduce the integration impact and, thus, the need for the charge, correct?

A Yes. In the Stipulation, Section II.A describes these types of facilities as controlled solar generators.

Q Right. But as I understand it, none of the details have yet been worked out as to what exactly would be required with respect to either the -- the battery design or the operation protocols; is that correct?

A I have not seen any formal energy storage protocol that would govern such a system, but I think -- I believe the testimony of Duke witnesses have discussed developing in house those storage protocol, and I do know that there will be ongoing meetings between Duke and

OFFICIAL COPY

Jul 29 2019

market participants for Tranche 2 to also discuss specifically energy storage protocol, so -- yeah.

Q And would you agree that the viability of this off ramp, if you will, from paying the charge has a material significance to the universe of facilities who may be subject to this charge? Maybe I can rephrase my question a little bit better.

You are in front of the Commission with a proposal that would result in a significant charge -- we talked about numbers ranging from 200 to $600 million the other day -- on a universe of facilities and businesses in this state, correct, and -- and so in evaluating the acceptability, the financial viability, the -- the policy advisability of that charge, don't you think it's material to understand fully the opportunity to those facilities to have to mitigate that charge before the charge is finalized?

A I think in this proceeding, as the Public Staff we're most concerned about getting the avoided cost correct and as accurate as possible, and that includes the SISC. And to the extent that allowing a controlled solar generator to avoid the SISC and -- and having that controlled solar generator be given a financial incentive to operate in a way that reduces ancillary services

OFFICIAL COPY

Jul 29 2019

required to integrate it, I think we do believe that that is an important component of this. But, you know, we reached a Stipulation in order to provide that -- that off ramp with the expectation, I think, that that off ramp would be available fairly quickly and to facilities that were -- that would be subject to the charge.

Q What is the need, from a practical matter, to finalize the details of the charge, particularly in the face of scientific uncertainty prior to the time of resolving the mitigation opportunity?

A Mr. Metz may have something to add to this, but I -- I think from our perspective, delaying the charge for another two years while aspects of the studies are continually updated would result in any solar connected between now and the next avoided cost proceeding would be exempt from the charge and it would be ratepayers that would end up paying for the additional ancillary service burden to integrate those sources.

So from our perspective, after a thorough review of the Astrapé study and its results and finding that the charge was reasonably calculated, we felt that it was appropriate to assess that charge now and -- and hope that the -- and work with Duke and the QF developers to ensure that the energy storage protocol that would

OFFICIAL COPY

Jul 29 2019

provide an off ramp and a financial incentive to be developed as quickly as possible.

Q I just have two more questions.

A (Metz) I'd like -- like to add to that.

Q Yeah. Sure.

A As -- as you discussed that, I mean, material impacts to the QF industry, approximately $600 million is the numbers that you proposed earlier. From our charter we look at that as, I mean, understanding your point, but that's also $600 million that's being subsidized by ratepayers for ancillary service costs being imposed by them that is not being recovered. So I mean, but that -- I mean, that is a material component.

Q I understand that's your position. Let me just ask two more questions, Mr. Thomas, following up on my last line of questioning. Do you have any estimate of the number of existing QFs that will have expiring PPAs in the next two-year period?

A (Thomas) I do not have that number directly in front of me, no.

Q Well, with respect to standard offer, the standard offer projects that are in the ground today are typically under 15-year PPAs, are they not?

A I believe so, but I -- I just want to -- you

OFFICIAL COPY

Jul 29 2019

know, the Public Staff works on CPCN applications and -- and we see the interconnection queue, but we don't participate in PPA or contract negotiations.

Q Sure. Will you accept, subject to check, that the great majority of exiting QFs are subject to 15-year PPAs, standard offer PPAs?

A Subject to check, yes.

Q And would you also accept that the vast majority, if not all, of those projects came online after 2007, and -- and a much greater majority of them came -- or a substantial portion of them in much later years, 2009, 2010, and beyond?

A Subject to check, I'll accept that.

Q So the -- the earliest possible date when we're going to start to see these potential renewals would be 2022, three years from now?

A I believe that the math works out.

Q Okay. And then with respect to new -- new nonstandard offer QFs, have any PPAs, to your knowledge, been executed this year with QFs that did not form LEOs prior to November 1st, 2018?

A Once again, I'm not aware of PPAs because just simply, as the Public Staff, we don't participate in PPA negotiations, so there could be. I really don't know.

OFFICIAL COPY

Jul 29 2019

Q Thank you very much.

MR. LEVITAS: I have nothing further.

MS. KEMERAIT: Madam Chair, I just have a few questions specifically for Mr. Metz.

CROSS EXAMINATION BY MS. KEMERAIT:

Q And Mr. Metz, I'm going to be asking questions on behalf of both NCCEBA and Ecoplexus because the questions overlap and I thought it would be more expedient from a time perspective to combine the questions.

A (Metz) Very well.

Q And Mr. Metz, you've provided supplemental testimony in which you provided quite of bit of information about the addition of energy storage to an existing facility and the rates that should be applicable when energy storage is added to a facility. Is that -- is that my correct understanding?

A I provide a very truncated version, but yes.

Q Okay.

A I tried to identify some of the issues that need to be addressed.

Q And in your testimony, I think, specifically for the Commission's reference on page -- and this is your supplemental testimony on page 3, you described the

OFFICIAL COPY

Jul 29 2019

challenges of the intermittent nature of solar, and when you discuss the -- the challenges of the intermittent nature of solar, you provided some information about how energy storage could address and reduce those challenges; is that correct?

A Yes. As we've had much discussion in this hearing, as well as previous hearings, of the volatility, to the extent that we can mitigate or even reduce the volatility and, therefore, increase predictability and provide a better signal to the Utility who is ultimately responsible for the grid higher capacity value or higher capacity component, I think that's intrinsic.

Q And those benefits would be to both the Utility's grid and also to the ratepayers; is that -- is that your position?

A That is correct.

Q And we -- with Mr. Norris' testimony earlier today, we talked about the amount of energy storage that -- his knowledge of the amount of energy storage that Cypress Creek Renewables has deployed. Can you elaborate on the amount of energy storage that is currently deployed in North Carolina? Can you quantify that amount?

A I do not have those numbers handy.

OFFICIAL COPY

Jul 29 2019

Q Would it be fair to say that very little energy storage has been -- has been deployed thus far in North Carolina?

A That is correct, and I think that's -- part of the reason that the Public Staff did its initial comments is that we're identifying, as we're working through this transition period, that we tried to utilize or -- or tried to better utilize or move forward of how we can better incorporate technologies into overall system.

A (Thomas) If I can just add, are you talking about energy storage or battery storage, because there is significant energy storage, particularly Bad Creek in -- in the DEC territory.

Q Okay. Battery storage.

A Okay. Thank you.

Q Okay. And -- and Mr. Metz, do you believe that it's important from a policy perspective for the state and for the Commission that policies are not put into place that would frustrate the deployment of storage with existing solar facilities?

A (Metz) Well, you're asking me a policy decision, which is slightly above my pay grade. I'd like to elaborate that we can -- we need to work through the challenges and identify them. I believe that's part of

OFFICIAL COPY

Jul 29 2019

the stakeholder -- pushing the stakeholder involvement, is looking at the engineering, the commercial, the regulatory challenges that are all in front of us today.

Q And -- and I'll ask you at the -- the end just a couple of questions about the stakeholder process or working group that you have recommended, but Duke's position is -- I just want to state this to frame the -- my next few questions. Duke's position is that when energy storage is added to an existing solar-only facility, that the existing PPA for the solar-only facility will be terminated and a new PPA will be required for the underlying facility and the storage portion at the current avoided cost rates. Is that -- is that your understanding?

A That's my general understanding, but I believe Duke, through the supplemental rebuttal, if I said that correctly, had made some comments towards the end of the testimony saying if the Commission were to move forward under this approach, they were making some other -- different recommendations in that.

Q Okay. And we would be, I think, very supportive of Duke moving off of its position that the underlying PPA would have to be terminated and that the underlying facility would lose its rights to the -- the

OFFICIAL COPY

Jul 29 2019

rates under the existing PPA. But the Public Staff's position is, and to -- for ease of the question, just please tell me if I'm stating it correctly, is that the underly--- that the PPA, the compensation for the underlying solar-only facility would continue to be compensated under the rates for the existing PPA, but the energy -- the added energy storage portion would be subject to the new avoided cost rates.

A That would be correct and, again, with the caveat that we work through all the commercial terms, engineering challenges, and regulatory roadblocks.

Q Okay. And in regard to the -- working through the engineering and the technical challenges, by that what you're referring to is that we would need to determine a method of measuring the output from the underlying solar-only facility and the added energy storage facility; is that the -- the challenge that you're -- you're referring to?

A Right. And part of that element is it's -- it's not going to be a one size fits all. There's going to be different battery manufacturers. There are going to be different implementations. You'll have the, for lack of a better word, larger batteries doing huge time shifts and you could have the smaller batteries that do

OFFICIAL COPY

Jul 29 2019

more frequency regulation. I believe as one of the witnesses stated earlier today, for frequency regulation sometimes it's better to do AC coupled because they can react faster and they don't have the system lengths used to go through all the systems and charging and discharging time. But if you're doing genuine time shifting or large peak arbitrage, then it may behoove you to do DC coupled.

Q And Mr. Metz, have you have had -- you've had an opportunity to review the supplemental testimony of Michael Wallace's of Ecoplexus?

A Yes, I have.

Q Okay. And Mr. Wallace provided some detailed information about technical solutions that he's proposed for ways that the output could be separately measured?

A Yes, he did, and some of that was talking about the -- the DC meter, understanding some of the arguments we heard today and the ANSI standards that may not be currently governing DC revenue-grade meters. But there's other ANSI standards that we can apply, other technologies, i.e., shunts. You can measure the DC -- or the DC amperage moving through the system. There's other mechanisms in place where we're not restricted solely to ANSI standards for DC grade revenue meters because

OFFICIAL COPY

Jul 29 2019

overall -- and then they were talking about accuracy.

Q And so Mr. Metz, I -- I'm just going to state what you've mentioned in your testimony. You did say that you believed that these technical or engineering challenges you believe can be overcome if a stakeholder group was convened to work through these technical challenges. Is that -- is that your position?

A I believe that's a step in the right direction. As being part of stakeholder groups, sometimes you don't always reach consensus, but the intent would be to work together, identify, and having an open forum and work through the issues.

Q And so you have recommended a working group be convened to meet and try to resolve this issue on an expedited fashion?

A Expedited and truncated with a narrow focus in trying to work on these topics. It's sort of lessons learned through NCIP. Larger, you make your stakeholder process the more input you have, which it's available, but sometimes the more input you have and the more topics you put on the table, the quicker you cannot reach consensus.

Q Okay. And I think I would not disagree with that statement. And my last question, Mr. Metz, just as

OFFICIAL COPY

Jul 29 2019

a point of clarification for some other information that we heard earlier today, can you clarify that it is possible to add energy storage to an existing facility without increasing the overall output of the facility?

A Simple, yes, but the engineering hat is quickly coming on. To the extent that there are -- there could be mechanisms which one could bypass or increase the nameplate, there -- there has to be control as validated on -- on the back end of it, i.e., take an inverter. Inverter is rated at, we'll say -- we'll have one inverter that's rated at 5 MW. Well, typically, inverters are rated greater than 5 MW. They have a little bit of headroom. You allow the headroom for thermal fatigue and thermal derating and there's a bunch of other stacking elements. And typically you'll either have software settings or DIP switch settings that would set the output of the overall facility. Not saying that we have any bad players on this system that would intentionally disable sort of those protocols, but that is a potential, and those things probably should be addressed through the commercial terms and conditions, and that's one of the conditions that outline.

Q And assuming that we're not talking about bad players, and many solar developers are looking to add

OFFICIAL COPY

Jul 29 2019

energy storage without the intent of increasing the overall capacity of the facility; is that your understanding?

A I would say yes, that's correct.

Q Okay. Thank you very much.

MS. KEMERAIT: That's all the questions I have.

CROSS EXAMINATION BY MS. HUTT:

Q Maia Hutt from the Southern Environmental Law Center on behalf of SACE. My questions are primarily for you, Mr. Thomas. And some of my questions are going to relate to the Astrapé study, ancillary service study, so have you been here the whole time hearing Mr. Wintermantel and Mr. Kirby's testimony?

A (Thomas) I have.

Q Okay. Great. Thanks. So one question offhand. Do you think that the size of a balancing area influences the amount of reserves necessary to integrate solar?

A I think generally my understanding, from my review of other integration studies as well as the Astrapé study, is that the -- the amount of balancing reserves required to integrate a certain capacity of intermittent resource is generally dependent on the type of resource and the quantity of that resource and perhaps

OFFICIAL COPY

Jul 29 2019

less dependent on the system size or -- or characteristics.

A (Metz) I mean, and just to elaborate a little bit further on that, is we take solar, for example, I mean, the AC/DC ratio has, if you looked at the -- the peak generation, I mean, that has a significant impact on the potential volatility being increased in the system. So if we looked at, say, noon and -- and the solar system is at a hypothetical max output, the lower the DC to AC ratio would be, and let's say a cloud camera came on, the more volatility that could be introduced into the system because you don't have that headroom to absorb it or the energy that's being clipped wouldn't take care of it.

Q Thank you. Do you think that there are any factors, other than megawatts of solar on a system, that impact the volatility -- the -- the amount of load following reserves that would be necessary to add in order to adjust for an increase in solar?

A (Thomas) Certainly. Just as Mr. Metz implied previously, it depends on the characteristics of solar. Is it tracking or fixed tilt? What's the azimuth? What kind of DC to AC ratio you have. Where these facilities are located, how they're dispersed geographically. And, you know, the type of weather data that -- or the weather

OFFICIAL COPY

Jul 29 2019

that you have. And in addition, load volatility can -- can also play a part because load volatility and solar volatility often work to oppose -- to oppose each other and -- and provide less overall volatility.

So a lot of factors can influence the amount of reserves. It's more than just the -- the number of megawatts that are added, although that is a -- a significant factor.

Q Thank you.

A (Metz) And -- and just to maybe add also that, it's also complimentary to how the utility system is configured, I mean, because each utility system can be differently configured with different resources on how they can respond to volatility or load, or in a need event, ramp up or ramp down.

Q So would it be fair to say that it's an oversimplification to say I've added "x" amount megawatts of solar and, therefore, that should produce a consistent increase in reserve?

A In the raw form is it an oversimplification? Yes. But as applicable to the -- a study, the study takes all those characteristics into consideration. I believe Mr. Thomas can elaborate more of how the statistical models or the modeling analytics can address

OFFICIAL COPY

Jul 29 2019

those concerns.

A (Thomas) Yeah. I mean, if the only thing that you were looking at was -- was the -- the number of megawatts of intermittent resource added and the -- the resultant reserves, if that was the only metric you were looking at, yes, I think that would be overly simplistic, and that's why in my review of other integrations studies I looked, you know, into those studies' methodology and the way they modeled the intermittent resource and the way they modeled load and -- and so, you know, it is deeper than that. But at the end of the day, many of these studies do model in very similar ways a lot of times the way that they model load, the way that they model intermittent resources, so when you start to see, you know, correlation between the amount of reserves added for a particular block of intermittent resources, you see that studies are -- are producing similar results as they approach the same problem in different ways.

Q Thank you. So I understand that the Public Staff originally supported Mr. Kirby's concerns about the stringency of the LOLE FLEX metric, and one of the ways that, as I understand it, the Public Staff came to be more comfortable with that metric was to ask Duke and Astrapé to relax the reliability metric and perform a

OFFICIAL COPY

Jul 29 2019

sensitivity analysis; is that right?

A Yes. That is one of the ways, and the results were submitted as part of my testimony.

Q So that's your Exhibit C that you're referring to, right?

A Yes.

Q And in order to produce Exhibit C, post-processing techniques were used. Can you explain to me what those techniques were? How were they different from rerunning the model?

A Generally, my -- my understanding of the techniques used by Astrapé, and subject to check, but they looked at the model runs that had caused the failure and then looked at the model runs that were close to causing a failure and essentially decided how far down can I back my reserves to the point where I would have a significant other -- a significant increase in the number of model runs or the likelihood of a -- a model encountering a failure. So by just decreasing the model -- the required ancillary reserves just slightly, they were able to expose essentially a lot of these model runs that then now had an LOLE FLEX violation. So it was just indicative that the system, as it looks out five minutes and has perfect foresight, only missed one event in every

OFFICIAL COPY

Jul 29 2019

10 years, but it came awful close quite a few times. And -- and by reviewing the results of the original study, they were able to quantify how many studies were so close that a very small reduction in the following reserves would have caused those runs to be classified as a failure.

So it's not an exact rerunning of the model, but we felt that it was fairly accurate to -- to at least demonstrate that we weren't being pushed so far up this cost curve, this, you know, increasing ancillary services increasingly cost more and more dollars per MWh. We wanted to make sure we weren't so far up this curve that a very slight reduction in or change in the reserves would double or triple the -- the ancillary service cost, so that's what kind of put us at ease about -- about the LOLE FLEX metric, part of the --

Q Thank you for that explanation. So is there any information about the methodology used in these post-processing techniques that has been made available to the Commission?

A It may have been described in Duke's reply comments or Wintermantel's testimony, but off the top of my head, I can't recall if it was directly discussed.

Q So I know the results are in Exhibit C of your

OFFICIAL COPY

Jul 29 2019

testimony. I don't believe there was anything in Mr. Wintermantel's testimony that explain the post-processing techniques. So would you accept that, subject to check?

A Subject to check, yes.

Q Thank you. Okay. And just to confirm, relaxing that metric from 0.1 to 1.0 resulted in a 6.2 percent reduction in the calculated charge for DEC and a 1.9 reduction in DEP; is that right?

A Yes. I believe that a 1,000 percent increase in the LOLE FLEX metric did yield those -- those drops in the SISC.

Q Sorry. One thousand?

A It was a tenfold increase --

Q Okay.

A -- so it's 1,000 percent change.

Q Thank you. And so none of these reductions were actually incorporated into the proposed charge or that's explained in the Stipulation?

A No, they were not.

Q Okay. And then one of the other issues that I understand a sensitivity analysis was conducted in regards to is the islanding assumption. Mr. Wintermantel, I believe, testifies that there was a sensitivity analysis run where DEC and DEP's load and

OFFICIAL COPY

Jul 29 2019

volatility assumptions were combined. Were you familiar with that as well?

A Yes. Can you point me to the exact point so I can just reference it?

Q I think it's page 28 of his direct.

A Yes. I'm there, and I was aware of the -- the analysis that they run, and that was at the request of the Public Staff.

Q And that analysis resulted in a 15 percent reduction in the calculated charge; is that right?

A Mr. Metz may have something to add to this, but, yes, that -- that's my understanding. And like I said, the assumptions that they made to get there, we -- you know, we felt that they were possibly aggressive in the ways that they balanced the load.

A (Metz) So yes. We're talking about the island case sensitivity?

Q (Nods affirmatively.)

A So we had initial concerns when we were looking at their view of how the TBAs were treated as islands. We expressed those concerns through our initial comments, and we also had multiple conversations with Duke and Astrapé. And Astrapé went and reran the analysis, but as you read the context of how they were able to relax it to

OFFICIAL COPY

Jul 29 2019

15 percent is basically you tied Duke Energy Carolinas and Duke Energy Progress with a single conductor with infinite size, and said if no system restraints and we had all the available transmission capacity in the world, and we didn't have to follow any other NERC standards, which there's a good handful of them, there's a lot in TPL that you have to apply, there was a 15 percent reduction.

We took that under consideration and thought it was unreasonable at this time to allow or to evaluate the 15 percent reduction with that many -- with those condition sets. It was just not realistic.

Q So that 15 percent reduction is also not included in the calculated charge as it is now?

A That is correct.

Q And Mr. Wintermantel characterizes a 15 percent reduction as modest. Do you agree?

A (Thomas) I think a 15 percent reduction is 15 percent. It is a modest decrease compared to 50 percent.

Q I guess what I'm trying to get at is we're seeing a 15 percent reduction here, and I understand that that might be aggressive. We're seeing a 6 percent reduction from increasing the LOLE FLEX reliability metric. Doesn't that kind of start to add up at some

OFFICIAL COPY

Jul 29 2019

point?

A Well, I would agree that, you know, if you start to add these changes additively, that, yeah, you would start to see significant changes, but to say simply that you can do the island case and then, you know, reduce the LOLE FLEX metric and suddenly you will have a 6 plus 15, a 21 percent reduction in the SISC, is not accurate. These changes that are reflected in the cost of running these models are going to be overlapping. And in particular the islanding case, I mean, it portrays DEC and DEP as a single balancing authority, which I'm not a lawyer, but I -- I do not believe that that would be allowed under the rules that FERC sets on market power and things of that nature.

So we -- we really -- you can't just add those and say that they're going to produce a significant decrease. You would have to try to model them together. And based upon the realities of the way that the TBAs actually operate and the unrealistic nature of the island scenario, we -- we decided that was not a route or a sensitivity -- it was -- it was a good sensitivity analysis, but it was not something that we thought would be appropriate to bake into the actual charge.

Q Okay. That's understood. So --

OFFICIAL COPY

Jul 29 2019

CHAIR MITCHELL: Ms. Hutt, we're going to stop here for today. We will resume tomorrow morning at 9:30. We're adjourned. Thank you.

(The hearing was recessed, to be continued on July 19, 2019, at 9:30 a.m.)

OFFICIAL COPY

Jul 29 2019

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-100, Sub 158, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 29th day of July, 2019.

Linda S. Garrett

Linda S. Garrett, CCR

Notary Public No. 19971700150