PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Wednesday, July 17, 2019

TIME: 9:00 a.m. - 12:37 p.m.

DOCKET NO.: E-100, Sub 158

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

General Electric

Biennial Determination of Avoided Cost

Rates for Electric Utility Purchases

from Qualifying Facilities - 2018

VOLUME: 5

Noteworthy Reporting Services, LLC

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 South Wilmington Street
Raleigh, North Carolina 27601

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

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

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

FOR THE NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE:
Steven Levitas, Esq.
Kilpatrick Townsend & Stockton LLP
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 27601-2943

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

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION:
Robert F. Page, Esq.
Crisp, Page & Currin, LLP
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

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 THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER AFFECTING THE PUBLIC INTEREST:
Jennifer T. Harrod, Esq.
Special Deputy Attorney General
Teresa L. Townsend, Esq.
Special Deputy Attorney General
Office of the North Carolina Attorney General
114 West Edenton Street
Raleigh, North Carolina 27603

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

FOR THE USING AND CONSUMING PUBLIC:

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

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

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

E X H I B I T S

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4	NCSEA's Reply Comments filed .... On March 27, 2019	- /105
5	Beach Exhibit Number 1	106/ -
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P R O C E E D I N G S

CHAIR MITCHELL: Good morning. Let's go on the record, please. I believe we are with Dominion. Please call your witnesses.

MR. DANTONIO: Good morning, Chair Mitchell. Nick Dantonio with McGuireWoods on behalf of Dominion Energy North Carolina. With me also is Mary Lynne Grigg.

If it's okay with the Commission, I would like to move into the record Dominion's non-testimonial filings made in this docket before the witnesses come up.

CHAIR MITCHELL: Please do so.

MR. DANTONIO: Okay. Thank you. I would like to move that Dominion's initial statement and 14 exhibits filed on November 1, 2018, and Dominion's reply comments and two attachments filed on March 27, 2019, in this proceeding be included into the record.

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

(Dominion's initial statement and 14 exhibits filed on November 1, 2018, and Dominion's reply comments and two attachments filed on March 27, 2019 were admitted into evidence.)

MR. DANTONIO: Thank you. Dominion calls Bruce Petrie and Jamie Billingsly, who will be testifying as a panel pursuant to the order of witnesses filed on July 10th.

CHAIR MITCHELL: Good morning, gentlemen. Let's get you sworn in.

BRUCE E. PETRIE and JAMES M. BILLINGSLEY,
having first been duly sworn, were examined
and testified as follows:

DIRECT EXAMINATION BY MR. DANTONIO:

Q. I will start with Mr. Petrie. Would you please state your name and business address for the record?

COMMISSIONER GRAY: Please pull that close to you, sir. Some of us --

A. (Bruce E. Petrie.) My name is Bruce Petrie. I'm manager of generation system planning at Dominion Virginia Power. The business address is 5000 Dominion Boulevard, Glen Allen, Virginia.

Q. Okay. And did you cause to be prefiled in this docket, on May 21st of this year, 19 pages of direct testimony in question and answer form and an

Appendix A?

A. I did.

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

A. No, I don't.

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

A. Yes.

Q. Mr. Petrie, did you also cause to be prefiled in this docket on July 3rd of this year 17 pages of rebuttal testimony in question and answer form?

A. Yes.

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

A. No.

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

A. Yes.

MR. DANTONIO: Chair Mitchell, at this time, I would move that Mr. Petrie's direct testimony and Appendix A and rebuttal testimony be copied into the record as if given orally from the stand.

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

(Whereupon, the prefiled direct testimony and Appendix A and prefiled rebuttal testimony of Bruce E. Petrie was copied into the record as if given orally from the stand.)

**DIRECT TESTIMONY
OF
BRUCE E. PETRIE
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158**

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

A. My name is Bruce E. Petrie, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am Manager of Generation System Planning for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

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

A. I am responsible for forecasting total system fuel and purchased power expenses, and for financial studies related to the regulated generation assets. A statement of my background and qualifications is attached as Appendix A.

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

A. The purpose of my direct testimony is to discuss the Company's proposed re-dispatch charge related to intermittent generation qualifying facilities ("QFs") and address the appropriate assumed in-service date for standard offer QFs for purposes of calculating the avoided capacity rate.

Q. What are re-dispatch costs?

A. The Company uses the term "re-dispatch costs" to mean the additional fuel and purchased energy costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. Historically, these types of events were driven by load variations due to actual weather that differed from what was forecasted for the period in question. For example, most power system operators assess the generation needs for a future period, typically the next day, based on load forecasts, and commit a series of generators to be available for operation in that period. These committed generators are expected to operate in an hour-to-hour sequence that minimizes total cost. Once within that period, however, actual load may vary from what was planned and the committed generators may operate in a less than optimal hour-to-hour sequence. The resulting additional fuel and purchased energy costs, due to real time variability, can be characterized as re-dispatch costs. These re-dispatch costs are difficult to quantify and are not accounted for in the basic hourly production cost modeling that the Company does to calculate the forecasted avoided energy cost rates.

Q. Why did the Company propose the re-dispatch charge?

A. The Company proposed the re-dispatch charge in response to the North Carolina Utilities Commission's ("NCUC" or the "Commission") directives in its 2016 Avoided Cost Order[1] and the procedural order in this docket.[2] In the 2016 Avoided Cost Order, the Commission "f[ound] merit in the concept … that an evaluation of the Utilities' avoided costs should consider the

[1] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 148 (Oct. 11, 2017) ("2016 Avoided Cost Order").
[2] *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing*, Docket No. E-100, Sub 158 (June 26, 2018) ("2018 Procedural Order").

characteristics of the power supplied by a QF."[3] The Commission recognized that PURPA allows utilities to consider factors such as the availability of a QF's capacity, dispatchability and reliability, and the value of QF energy and capacity in establishing avoided cost rates. The Commission directed that with their initial filings in this proceeding, the Company, Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC ("Duke" and together with DENC, the "Utilities") consider a rate design that considers factors relevant to the characteristics of intermittent, non-dispatchable QF supplied power.[4] The 2018 Procedural Order reiterated that directive.

Q. Please describe the rationale and justification for the Company's proposed re-dispatch charge.

A. In this docket the Company used the same basic hourly modeling approach to calculate the avoided energy cost rates that it has used in recent previous avoided cost proceedings. Specifically, the Company calculated the proposed avoided energy rates by adding a 100 MW 7x24 flat block of zero-cost energy to the system, and then analyzing the difference in system production costs between the base case (without the 100 MW block) and the change case (with the 100 MW block). Because intermittent QFs (which for purposes of the Company's North Carolina service area are all, as I discuss below, solar generators) do not deliver energy at a constant MW level, the model results should be adjusted by an estimate of the $/MWh cost of the intermittency.

[3] 2016 Avoided Cost Order at 98.
[4] *Id.* at 98, 110-111.

Q. Please describe the methodology and pricing of the Company's proposed re-dispatch charge.

A. In its November 1, 2018, Initial Statement in this proceeding, the Company proposed to adjust the avoided cost energy payments to intermittent non-dispatchable QFs to reflect the increase in system supply costs caused by these types of generators.

The Company has viewed solar resources as potential supply options in its annual integrated resource plans ("IRPs") for more than ten years. As more and more intermittent generation like solar photovoltaic ("PV") is added to the grid, the level of uncertainty about re-dispatch costs increases due to the potential for unpredictable cloud cover. In order to assess the resulting re-dispatch costs, in conjunction with the development of its 2018 IRP, the Company performed a simulation analysis to determine the impact on generation operations at varying levels of solar PV penetration. To study the effects of these intermittent resources, hourly generation data from 26 individual sites was used to develop generation profiles from actual solar PV facilities currently interconnected to the Company's system. The study was performed at three different levels of solar penetration (80 MW, 2,000 MW, and 4,000 MW) to provide a range of results. The study was also performed for four different cost categories, each of which were given equal weight (all costs, PJM/purchases/sales, pumping costs/reserves, and generator costs only).

The resulting system costs were used to determine an overall cost impact attributable to the intermittency of these resources.

The levelized cost differential between each of the cases resulted in an approximate re-dispatch cost of $1.78/MWh caused by the intermittency of solar generation on the Company's system. The Company proposed to use this value to adjust the avoided energy cost payments made to intermittent, non-dispatchable QFs under Schedule 19-FP, for both standard offer QFs and larger QFs with negotiated PPAs.

Q. Is DENC's re-dispatch charge comparable to the ancillary services charge adjustment to the avoided energy cost rate proposed by Duke?

A. The proposals are not the same, but are complementary. As I understand it, Duke studied the impact on its system operations with increasing levels of intermittent, non-dispatchable solar generation, and found that the production variability of the renewable generation causes increased uncertainty in hourly and sub-hourly operations. This increased uncertainty, and the need to comply with NERC reliability standards, increases the required amount of operating reserves in the form of regulating reserves and balancing reserves, which causes increased power supply costs. In the context of this docket, the avoided energy costs for intermittent resources are lower than for firm dispatchable resources because the growth of intermittent resources in the system causes increased supply uncertainty and results in an increased need for regulation and operating reserves.

As noted in the Company's Initial Statement, DENC has not quantified the cost of additional ancillary services related to the integration of intermittent generation resources. However, while they address different types of costs, the Company believes that its re-dispatch charge and Duke's solar integration charge are complementary, as each represents a separate and distinct category of additional costs associated with intermittent, non-dispatchable QFs that the Utilities must bear in order to provide energy supply. In other words, DENC analyzed one aspect of the impact of resource intermittency, while Duke analyzed a different aspect. In the re-dispatch cost study the Company calculated, using hourly modeling, the increase in system dispatch costs (related to providing load following service) caused by higher levels of intermittent generation in the supply mix. Duke calculated, using sub-hourly modeling, the increase in system costs caused by having to carry more operating reserves due to higher amounts of intermittent generation in its supply mix.

Q. What was the Public Staff's position regarding the proposed re-dispatch charge?

A. The Public Staff did not oppose the concept of the re-dispatch charge, but did present a number of questions and concerns regarding the Company's proposal. First, the Public Staff recommended that the Company collect and administer re-dispatch costs separately from the avoided energy rate. Second, the Public Staff recommended that the Company calculate separate re-dispatch charges for solar, wind, biomass, etc. QFs in future avoided cost proceedings.

The Public Staff also disagreed with the Company's weighting of the different cost categories to determine the proposed charge. Whereas the Company gave equal weight to the cost categories it considered, the Public Staff recommended giving 100% weight to the "all costs" category and none to the other categories. Finally, the Public Staff disagreed with how the Company selected and weighted solar penetration levels when calculating the re-dispatch charge by weighting the 80 MW, 2,000 MW, and 4,000 MW penetration levels equally. The Public Staff instead recommended giving 70% weight to the 2,000 MW level, 30% weight to the 4,000 MW level, and no weight to the 80 MW level. Based on all of these recommendations taken together, the Public Staff calculated a charge of $0.78.

Q. Did the Public Staff raise any other questions with regard to the proposed re-dispatch charge?

A. Yes, in its initial comments the Public Staff also posed a number of questions about how the re-dispatch analysis was conducted, which the Company answered during discussions and emails exchanged subsequent to the filing of initial comments.

Q. What is the Company's response to the Public Staff's comments regarding the format of the charge (decrement to payment or separate line item)?

A. The Company proposed the charge as a decrement to the avoided energy rate in the interest of administrative efficiency, but as stated in its Reply Comments is willing to apply the charge as a separate line item on a QF invoice apart from the avoided energy rate if the Commission determines that approach to be appropriate.

Q. What is the Company's response to the Public Staff's recommendation that a re-dispatch charge be calculated for non-solar QFs in future proceedings?

A. As noted in the Reply Comments, the Company is willing to evaluate the potential for calculating charges for other types of QF generation in future cases.

Q. What is the Company's response to the Public Staff's recommendations with regard to weighting of cost categories and solar penetration levels?

A. The Company continues to believe that its initial approach to calculating the re-dispatch charge was appropriate, for the reasons presented in the Reply Comments. As also discussed in its Reply Comments, however, for the purpose of this proceeding and in the interest of narrowing the issues in dispute in this case, the Company is willing to agree to the weightings recommended by the Public Staff and the resulting charge of \$0.78/MWh, which represents a full dollar decrease from the charge that the Company initially proposed. Specifically, the Company is willing to recalculate the re-dispatch charge with 100% weight given to the "all cost" category, and 70% and 30% weight given to the 2,000 and 4,000 MW solar penetration levels, respectively.

Q. Did other intervenors respond to the Company's proposed re-dispatch charge?

A. Yes. The North Carolina Sustainable Energy Association ("NCSEA") asserted that the Company's re-dispatch charge fails to comply with the 2016 Avoided Cost Order because it does not take the form of a separate rate schedule and because it is based on generation technology rather than QF characteristics. NCSEA also claimed that the Company's re-dispatch proposal fails to account for the benefits associated with distributed solar generation.

NCSEA affiant Johnson contended that the Company's re-dispatch proposal overstates the costs and does not consider the benefits of distributed solar QF generation, including geographic diversity. Dr. Johnson presented his own calculation of a re-dispatch charge of $0.69, based on removal of the PJM and generation-only cost categories and the 80 MW solar penetration scenario.

Similar to NCSEA, the Southern Alliance for Clean Energy ("SACE") and its affiant Mr. Kirby challenged the Company's inclusion of the 80 MW solar penetration level and averaging of results from the three penetration levels, as well as averaging of results from the four cost categories, to determine the proposed re-dispatch charge. SACE argued based on these challenges that the proposal was not adequately supported and should be rejected.

Q. What is the Company's response to NCSEA's complaint about DENC not proposing a separate rate schedule?

A. As discussed in the Reply Comments, the Company carefully evaluated the Commission's directives in the 2016 Avoided Cost Order and recognizes the Commission's conclusion in that order that the Utilities should consider and propose rate schedules that consider the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity. In developing its proposal, DENC determined that it would be more efficient, and therefore benefit both the QF and the Company, to include the re-dispatch proposal in the existing rate schedule rather than to propose a separate rate schedule only for intermittent QFs. QF developers are sophisticated entities that can determine which parts of a standard avoided cost tariff apply to them. As noted in the Reply Comments, however, if the Commission determines that the re-dispatch charge and other aspects of the proposed standard tariffs applicable to intermittent QFs should be reflected in a separate rate schedule, the Company will comply with that determination.

Q. What is the Company's response to NCSEA's assertions regarding the focus on generation technology?

A. The Company disagrees that its proposal is not consistent with the 2016 Avoided Cost Order. The Company did derive the re-dispatch charge based on data associated with solar PV facilities currently interconnected to the

Company's system. It is also true, however, that in North Carolina, where all intermittent, nondispatchable QF generation in DENC's service area is solar, there is inevitably an overlap between the concepts of "generation technology" and "QF characteristics." The proposed charge is "based upon a consideration of the characteristics of the power supplied by" these QFs (those characteristics being intermittency and nondispatchability), and all of the intermittent, non-dispatchable QFs in the Company's North Carolina service area are at this point in time solar QFs. Practically, therefore, in North Carolina at this time, these terms present a distinction without a difference. As noted above, the Company is willing to evaluate the potential to calculate a re-dispatch charge for other types of intermittent, nondispatchable QFs in a future proceeding.

Q. Does the Company agree with the comments of NCSEA and SACE with regard to the actual derivation of the re-dispatch charge?

A. No. The Company believes that it appropriately weighted cost categories and solar penetration levels in calculating its re-dispatch costs for the reasons presented in its Reply Comments. However, the Company's willingness to revise its calculations based on the Public Staff's recommendations should address NCSEA's and SACE's concerns in this regard, as I discuss further below.

Q. What is the Company's response to NCSEA's contention that the charge reflects only costs and not benefits?

A. The Company disagrees with NCSEA. The Company did account for both costs and benefits associated with distributed solar generation in its re-dispatch analysis as well as in the basic avoided energy rate. As I have discussed, the re-dispatch study quantified the additional measurable costs of adding intermittent, non-dispatchable generation to the system. In addition, as I discuss below, the analysis reflected the benefits associated with PJM purchases and sales. The macro benefits of new solar generation, including zero fuel cost for solar generation, displacement of Company owned generation and PJM purchases during daytime hours, and the related fuel price hedge benefit, were reflected in the production cost modeling and in the separate hedge value adder to the avoided energy rates. However, the Company has not directly observed any benefits with respect to system dispatch and minute-to-minute operational control of the grid due to the addition of these types of resources to the system that are not already accounted for in the avoided energy costs.

Q. What is the Company's response to NCSEA affiant Johnson's contentions?

A. With regard to Dr. Johnson's contentions regarding geographic diversity, and its potential impact on re-dispatch costs, the solar sites that the Company evaluated for its analysis are in fact geographically dispersed throughout the Company's entire service area, including North Carolina (20 of the 26 sites are located in North Carolina, and 6 are in Virginia). However, the North Carolina portion of that service area is relatively small, with very limited geographic diversity as compared to the rest of the Company's footprint. As a result, the intermittency of solar QFs located in North Carolina is not mitigated by their geographic diversity throughout the Company's service area in the State.

Dr. Johnson also contended that re-dispatch costs can be reduced by engaging in power purchases and sales with other utilities and that the Company should net re-dispatch costs with PJM purchases and sales. PJM market purchases and sales are, however, accounted for in the Company's re-dispatch study, as the PLEXOS model used for the study assumed that the Company would sell excess power into PJM during the peak hours with higher LMP prices and make market purchases at low prices. As discussed in the Reply Comments, in calculating the re-dispatch cost, DENC netted market purchases and sales against each other, which resulted in a net benefit to the solar re-dispatch cost.

As I noted earlier, the Company is willing to re-calculate the re-dispatch charge by assigning no weight to the 80 MW penetration scenario as well as assigning 100% weight to the "all costs" cost scenario. This modification, and the resulting charge of $0.78/MWh, should address Dr. Johnson's concerns with the re-dispatch charge.

Q. Does NCSEA Affiant Johnson object to the concept of the re-dispatch charge itself?

A. No. While Dr. Johnson recommended that the Commission reject the re-dispatch proposal as made by the Company, he did not oppose the concept of a re-dispatch charge itself. Instead, he stated that it is "reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, because solar generation varies with cloud cover which cannot be forecast with perfect accuracy."[5] As noted above, Dr. Johnson actually calculated a re-dispatch charge applicable to DENC of $0.69. The recalculated re-dispatch charge of $0.78/MWh that the Company is willing to offer, consistent with the Public Staff's comments, is very close to Dr. Johnson's proposed charge of $0.69/MWh.

Q. What is the Company's response to SACE?

A. The Company's willingness to re-calculate the re-dispatch charge as recommended by the Public Staff should address SACE's and affiant Kirby's concerns regarding the selection and weighting of the solar penetration levels and the averaging of cost categories.

Q. Do you have anything else you would like to add about the proposed re-dispatch charge?

A. Yes. Currently there are 72 solar QFs operating in DENC's North Carolina service area, representing approximately 501 MW of solar capacity. Once all

[5] Johnson at p. 18.

of the QFs with which the Company has executed power purchase agreements ("PPAs") come online, that total will rise to 691 MW, which significantly exceeds the Company's 2018 average on-peak load of approximately 525 MW. The Company's proposed re-dispatch charge represents the first step in quantifying the costs of integrating these large volumes of solar PV generation onto its system, which was first addressed in the 2012 avoided cost case, Docket No. E-100, Sub 136. The Company will continue to work on this issue, but for purposes of this biennial period believes that the re-dispatch charge is fair to both QFs and the Company's retail electric customers, because it will provide energy payments to QFs that better reflect the Company's actual avoided energy costs.

Q. Shifting to the second topic you are addressing, how did the Company calculate the capacity rates presented in its Initial Statement?

A. The Company's proposed capacity rates are based on the installed cost of a combustion turbine ("CT") peaker facility, whose underlying costs are drawn primarily from the 2018 Brattle Report, which assumes a 2022 commercial operation date, and then de-escalated to January 2019 to coincide with the start of the biennial rate period. Except for recommending that the Utilities should consider in future filings the cost of a CT on a brownfield site (versus the cost of a greenfield CT), the Public Staff did not oppose the Company's underlying costs, adjustments, or timing of the hypothetical CT facility.

Q. Other than the Public Staff, did any other intervenor comment on the Company's method of calculating standard avoided capacity rates?

A. Yes. In its comments NCSEA contended that the Company unreasonably assumed a January 2019 in-service date for QFs eligible for rates established in this proceeding, due to delays in the interconnection queue. NCSEA claimed that a QF entering into a Sub 158 PPA will not come online until December 2021 or later, and that December 31, 2021 should therefore be used as the presumed in-service date for the purpose of calculating avoided capacity costs. NCSEA also suggested that the Utilities should calculate avoided cost rates for negotiated PPAs based on the presumed in-service date of the QF. Dr. Johnson made similar assertions, including that DENC's assumed in-service date was arbitrary and unrealistic. He claimed without support that "few QFs are likely to seek to establish LEOs under the new rates until after the rates have been finalized," and concluded that "it is reasonable to assume a QF eligible for these rates will be place[d] in service … on or about December 31, 2021."[6]

Q. To your knowledge, has NCSEA or any other party previously raised this argument in an avoided cost proceeding?

A. Not to my knowledge, no.

[6] Johnson at pp. 58-59.

Q. Does the Company agree with NCSEA's contentions?

A. No. The purpose of this docket is to develop reasonable avoided cost rates that apply to small QFs that sign a contract during the 2019-2020 biennial period. NCSEA's proposal would be impractical and inefficient, particularly for standard contracts. For example, would the assumed in-service date change with each avoided cost proceeding? Based on what standard? The proposal is also itself arbitrary. This is shown by the reality that, while assuming a January 1, 2022 in-service date may benefit a QF that is eligible for this biennial period's rates but does not for whatever reason come online until after 2019, that assumption could also result in over-payment to a QF that does achieve commercial operations before January 2022.

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. As discussed in the Company's Reply Comments, 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. In addition, giving a QF multiple pricing choices gives them free optionality, whose cost is born by electric customers. 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 interconnection study process? Would the utility be required to recalculate the rates? The proposal presents too many uncertainties to be appropriate.

Q. Are there any other reasons why the Company opposes NCSEA's proposals?

A. Yes. NCSEA's generalized assertions regarding the likely time frame in which a QF will come online do not support its proposal. It may be the case that a QF that submits an Interconnection Request and establishes an LEO at or near the same time (e.g., in December 2018), and qualifies for rates established in this proceeding, may not come online during 2019. However, given the time-intensive nature of the interconnection study process, which is known to developers and the Utilities alike, it would be reasonable for a developer to submit its Interconnection Request in advance of establishing its LEO, and thereby enable that QF to come online in early 2019. For example, if a developer submitted an Interconnection Request in December 2016 and established an LEO in December 2018, then that QF could have progressed through the study process and come online in 2019. NCSEA's proposal is based on the assumption that all QFs eligible for rates established in this proceeding will have not commenced the interconnection study process until this biennial period, but NCSEA does not offer any support for that assumption, and does not account for QF developers that planned ahead, started the interconnection process much earlier, and will come online this year.

Finally, 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, and this is not consistent with the Company's experience as I understand it. My understanding is that, in each of the biennial periods that have occurred since the development of the LEO standard in the 2014 avoided cost case (Docket No. E-100, Sub 140), developers have established LEOs with the Company before the issuance of a final order in the case. Given this reality, and the reasonableness of considering that a developer would know enough about how this process works to time its Interconnection Request and LEO in order to come online by a certain time frame, I do not agree that a 2019 assumed in service date is either arbitrary or unrealistic.

Q. Did the Public Staff address NCSEA's proposals in its Reply Comments?

A. Yes. The Public Staff stated that "[f]or purposes of establishing the term for a standard offer facility, 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."[7] The Company agrees with the Public Staff.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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[7] Public Staff Reply Comments at p. 29.

APPENDIX A

BACKGROUND AND QUALIFICATIONS
OF
BRUCE E. PETRIE

Mr. Petrie graduated from Clarkson University in 1983 with a Bachelor of Science degree in Mechanical Engineering. He earned a Master of Business Administration degree from Virginia Tech in 1988.

Mr. Petrie worked for Niagara Mohawk Power Corporation from 1988 through 1998 in generation planning, fuel procurement, and wholesale power marketing, and then at Old Dominion Electric Cooperative from 1998 until 2001 as a power supply analyst. He joined Virginia Power in April 2001 as an electric pricing and structuring analyst. His responsibilities included the pricing and structuring of wholesale electric transactions, project financial analysis, and analytical support to the Energy Supply group.

In October 2007, Mr. Petrie was promoted to Manager of Generation System Planning for Dominion Virginia Power. He is currently responsible for the Company's mid-term operational forecast.

REBUTTAL TESTIMONY
OF
BRUCE E. PETRIE
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

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

A. My name is Bruce E. Petrie, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am Manager of Generation System Planning for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Did you file direct testimony in this proceeding on May 21, 2019?

A. Yes.

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

A. The purpose of my rebuttal testimony is to respond to the testimony filed by the Public Staff, the North Carolina Sustainable Energy Association ("NCSEA") and the Southern Alliance for Clean Energy ("SACE") on June 21, 2019, with regard to the Company's proposed re-dispatch charge, the assumed in-service date for qualifying facilities ("QFs") receiving standard offer rates and terms in this proceeding, the process for power purchase agreements ("PPAs") that are terminating, and issues related to providing accurate price signals to QFs.

<u>**Redispatch Charge**</u>

Q. Please summarize the current status of the Company's re-dispatch charge proposal.

A. As discussed in detail in my direct testimony, for purposes of this proceeding the Company is willing to agree to the cost category and solar penetration level weightings recommended by the Public Staff in its initial comments. Specifically, the Company is willing to recalculate the charge with 100% weight given to the "all cost" category, and 70% and 30% given to the 2,000 and 4,000 MW solar penetration levels, respectively. This results in a recalculated re-dispatch charge of $0.78/MWh.

Q. Did the Public Staff address the re-dispatch charge in its testimony?

A. Yes. Public Staff witness Thomas testified that the Company's re-dispatch charge 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."[1] Witness Thomas described the Company's approach to calculating the charge and stated that in general the Public Staff believes the charge to be a reasonable

[1] Testimony of Jeff Thomas at 20 (June 21, 2019) ("Thomas Testimony").

attempt to quantify the costs caused by intermittent generators.[2] He noted that the Public Staff identified concerns with the weightings that the Company applied to the various scenarios used to calculate the charge, and referenced the Public Staff's recommended weightings that result in a re-calculated charge of $0.78/MWh, as well as the Company's willingness to agree to those recommendations.[3]

Q. What is the Company's response to witness Thomas' testimony?

A. The Company remains willing to accept the Public Staff's recommended modifications to the calculation of the re-dispatch charge and the resulting charge of $0.78/MWh for purposes of this proceeding.

Q. Did NCSEA offer testimony on the re-dispatch charge?

A. Yes. NCSEA witness Beach testified generally on the re-dispatch charge together with the solar integration charge proposed by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC ("Duke"). Witness Beach recommended that the Commission not adopt either of these proposed charges, and asserted that any cost to integrate solar resources will be offset by benefits of these resources that he contended the Utilities have not recognized.[4]

NCSEA witness Harkrader also testified in general terms regarding the re-dispatch charge within her discussion of Duke's solar integration charge.

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[2] *Id.* at 20-21.
[3] *Id.* at 21-22.
[4] Testimony of R. Thomas Beach at 5 (June 21, 2019) ("Beach Testimony").

She asserted that the Utilities' proposals are harmful to the North Carolina solar industry, and recommended that "rather than penalizing QFs with new fees," the Commission should implement programs to "allow and reward" QFs that provide ancillary services.[5]

Q. What is your response to the NCSEA witnesses' testimonies?

A. Notably, while recommending that the Commission reject the re-dispatch charge, witness Beach did not offer any specific critiques of the re-dispatch charge itself in his testimony. Witness Beach did claim that the "utilities" have not properly considered and quantified the benefits of solar in presenting their proposed charges. To the extent these assertions refer to the Company, I do not agree. As discussed in my direct testimony and in the Company's reply comments, the Company has properly considered both the benefits and the costs of QF resources in the avoided cost rates and in the re-dispatch charge.[6]

To the extent that witness Harkrader's testimony was directed at the Company, I would disagree with characterizing the re-dispatch charge as a "penalty." The Company's avoided energy costs are based on the difference in system production costs between a PROMOD model case without incremental QF energy deliveries and a case with a 100 MW flat block of zero-cost QF energy added to the system. Because QFs do not deliver the

[5] Testimony of Carson Harkrader at 16 (June 21, 2019) ("Harkrader Testimony").
[6] Direct Testimony of Bruce E. Petrie at 12 (May 21, 2019) ("Petrie Direct Testimony"); *Reply Comments of Dominion Energy North Carolina* at 19-21 (Mar. 27, 2019) ("DENC Reply Comments").

same amount of energy every hour (*i.e.*, they are intermittent and fuel-limited), the rates derived from those model results should be adjusted to reflect the cost impact of the QF generation profile. The re-dispatch charge represents that adjustment, which improves the accuracy of the avoided energy rates and accounts for the way that the rates are calculated from the modeling results.

Q. NCSEA witness Harkrader also testified that the solar integration charge should not apply to existing QFs when their current contracts expire.[7] Do you agree with her position as to the re-dispatch charge?

A. No. An existing QF that signs a new contract should be subject to the same prevailing rates, charges, and terms that apply to a new QF, including any re-dispatch charge approved by the Commission.

Q. Did SACE provide testimony on the re-dispatch charge?

A. Yes. SACE witness Kirby asserted a lack of detail supporting the re-dispatch charge calculations and contended that the Company did not include an analysis of the benefits of solar projects. He also, however, testified that the Company's agreement to remove the 80 MW solar penetration scenario from its analysis and to solely use the "all costs" category for its re-dispatch charge analysis instead of averaging all four of its originally proposed cost categories helps alleviate his concerns on these fronts.[8]

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[7] Harkrader Testimony at 17.
[8] Testimony of Brendan Kirby at 43-45 (June 21, 2019) ("Kirby Testimony").

Q. What is your response to witness Kirby?

A. As discussed above, the Company did consider the benefits of solar facilities interconnected to its system. However, for purposes of this proceeding, as witness Kirby acknowledged, the Company's willingness to recalculate the re-dispatch charge as recommended by the Public Staff appears to have mitigated his stated concerns.

Q. Did NCSEA witness Johnson offer testimony on the re-dispatch charge?

A. Witness Johnson did not address the re-dispatch charge in his testimony. However, in his affidavit submitted earlier in this proceeding, witness Johnson stated that "[i]t is reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, because solar generation varies with cloud cover which cannot be forecast with perfect accuracy."[9] He described his objections to the Company's approach to calculating the charge, but continued to acknowledge the presence of re-dispatch costs ("As more data is collected, and solar modeling becomes more sophisticated, any additional re-dispatch costs resulting from solar generation should diminish;" "while these costs will never completely disappear, they will be heavily concentrated in specific time periods").[10] He contemplated reduced re-dispatch costs depending on the inputs assumed for the calculation, including a charge of $0.69/MWh if the 80 MW solar penetration scenario and two cost

[9] Affidavit of Benjamin F. Johnson at 18 (P 53) (Feb. 12, 2019).
[10] *Id.* at 18-19 (P 55).

categories are excluded from the calculation.[11]

Q. Do you have any other comments regarding the Company's proposed re-dispatch charge?

A. The Company continues to support its recalculated re-dispatch charge of \$0.78/MWh, consistent with the Public Staff's recommendations, as a reasonable way to reflect in the avoided energy rates to be approved for this biennial period the increased fuel and purchased energy costs resulting from distributed solar QFs in the Company's service area. The Company believes that the modifications to the calculation recommended by the Public Staff and agreed to by the Company address the majority of NCSEA's and SACE's initial concerns with the re-dispatch charge.

<u>Innovative QFs</u>

Q. Please summarize the issue raised in this proceeding regarding the exemption of "innovative QFs" from an integration charge.

A. In their comments filed in this proceeding, the Public Staff and NCSEA discussed whether or not solar QFs with battery storage capability should be subject to Duke's proposed integration charge. On May 21, 2019, Duke and the Public Staff filed a stipulation that, in part, would exempt QFs from the Duke integration charge if they can operate the facility in a manner that "materially reduces the need for additional ancillary service requirements," as determined by Duke, to include battery storage, dispatchable contracts, or

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[11] *Id.* at 19-20 (PP 59-60).

other mechanisms.

Q. How does this topic relate to the Company?

A. In his testimony, Public Staff witness Thomas stated that the Public Staff agreed with NCSEA that innovative QFs may reduce the need for additional ancillary services in a way that would make Duke's proposed integration charge unnecessary. He testified that "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 ancillary services costs on the system, it should not be subject to [Duke's solar integration charge] or, to a lesser extent, the [Company's re-dispatch charge]."[12]

Q. What is your response to Public Staff witness Thomas' suggestion that a QF that can show it will not impose additional ancillary services costs should not be subject to the re-dispatch charge to some extent?

A. While the addition of battery storage may potentially smooth the QF output during certain hours, the shape of the MW output during the middle of the day, in between charging in the morning and discharging in the evening, will still exhibit a considerable amount of volatility, which the redispatch charge would account for. In addition, even though there may be a smoothing effect during certain hours, the Company has not yet studied this effect, which

[12] Thomas Testimony at 27-28.

would need to be calculated to determine any discount to the re-dispatch charge that would be appropriate. The Company therefore believes that the recalculated $0.78/MWh charge should apply to all solar QFs in this biennial period, and the Company will update the charge as appropriate in future proceedings based on further modeling to analyze the impact of new solar QFs co-locating battery storage at their facilities.

Q. Did any witnesses raise the subject of existing QFs adding battery storage to their facilities?

A. Yes. NCSEA witness Harkrader stated that the Utilities should allow QFs currently in service to modify facilities, including by adding battery storage, so long as maximum export capability is maintained.

Q. Will you address this issue in your rebuttal?

A. No. This issue is addressed in the supplemental testimony filed by Company witness Billingsley on June 25, 2019.

<u>QF In-Service Date</u>

Q. Please summarize the Company's position on the issue raised by NCSEA regarding adjusting the QF in-service date.

A. As explained in my direct testimony[13] and in the Company's reply comments,[14] for small QFs entering into standard offer PPAs, the Company has assumed a January 2019 start date in the same fashion it has for every

[13] Petrie Direct Testimony at 17.
[14] DENC Reply Comments at 30-31.

other recent avoided cost proceeding. This is the most administratively efficient method to develop standard rates and terms for small QFs. It would, on the other hand, be impractical to use an assumed QF in-service date that is a full year past the end of the two year biennial period, especially considering the fact that the Company will file new forecasted avoided cost rates on November 1, 2020.

Q. Did the Public Staff offer testimony on this topic?

A. Yes. Public Staff witness Hinton testified, for purposes of establishing the term for a standard offer contract, that 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 and new facilities equitably.[15] The Company agrees with witness Hinton on this matter.

Q. Does NCSEA continue to advocate for a 2021 assumed start date?

A. Yes. NCSEA witness Johnson testified that he continues to believe an assumed in-service date of January 1, 2019 for QFs that sign a contract during this biennial period to be unrealistic, and that an assumed date of December 2021 is more reasonable. He did recognize that smaller QFs can proceed more quickly than larger ones, and that it might therefore make sense to use an earlier in-service date for such smaller projects. In the alternative to a specific assumed date, he suggested that the Utilities could be required to

[15] Testimony of John R. Hinton at 13 (June 21, 2019) ("Hinton Testimony").

publish a schedule of rates (or a formula) specifying the applicable rate for all projects signing a contract during the 2019-20 biennial period, and each QF would receive the applicable rate based on its actual in-service date.[16] He claimed that it would not be difficult or burdensome for utilities to calculate a schedule of rates tied to the actual in-service date.[17]

Q. What is the Company's response to witness Johnson?

A. The Company does not support witness Johnson's proposal to use a later presumptive in-service date for standard offer contracts for the same reasons articulated in my direct testimony. In addition, he has not offered any evidence specific to DENC to support a December 31, 2021 in-service date.

With regard to Witness Johnson's alternative proposal for a schedule of rates, it would be unreasonable to complicate the standard offer with varying in-service dates and rate calculations. Any additional granularity that might be achieved would be outweighed in the Company's view by the extra administrative burden to produce such a schedule of rates as well as the potential impact on customers. This approach would allow QFs to simply time their commercial operations date to the point in time during the biennial period when the rates are highest, and in the Company's view is not consistent with a QF's election to provide energy and capacity pursuant to a legally enforceable obligation ("LEO") with rates calculated at the time the obligation was incurred. Finally, as the Company has stated previously in these avoided

[16] Testimony of Dr. Ben Johnson at 23-24 (June 21, 2019) ("Johnson Testimony").
[17] *Id.* at 26.

cost proceedings, PURPA requires utilities to purchase the QF output; it does not require utilities to provide QFs with a level of optionality required to maximize QF earnings.

Expiring PPAs

Q. Please summarize the topic of expiring PPAs.

A. In their comments filed in this proceeding, NCSEA and the NC Hydro Group discussed their views as to how PURPA PPAs whose terms are expiring should be treated.

Q. Did the Public Staff testify on this issue?

A. Yes. Public Staff witness Hinton recommended 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. He stated that 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. He stated further that likewise the period of time should not be so long that a QF could contract for rates that are misaligned with current avoided costs.[18]

Q. What is the Company's response to witness Hinton's recommendation?

A. The Company believes that a one-year notice period ahead of the expiration

[18] Hinton Testimony at 13-14.

date of a current PPA, with the requirement to execute the PPA consistent with the currently effective LEO form, achieves the balance witness Hinton identified between providing the QF with sufficient time to make an informed decision but not so much time as to result in inaccurate avoided cost rates.

Q. Do other intervenors address this topic?

A. Yes. NCSEA witness Johnson recommended that the Commission clarify that QFs with contracts expiring between now and 2028 are fulfilling an existing capacity need, and will continue to receive full capacity cost recovery if they sign a "renewal contract."[19] He recommended that in order for the QF to continue receiving capacity payments the Commission should require QFs to file notice with the utility at least 3 years before the current PPA is set to expire indicating the QF's commitment to continue to provide capacity.[20]

Q. What is your response to witness Johnson's testimony?

A. I do not agree with witness Johnson's recommendation that a QF could notify a utility three years ahead of its PPA expiration and lock in a right to capacity rates as of that time. As discussed above, the Company believes that a one-year notice period is a reasonable amount of time that meets witness Hinton's suggestions to be long enough for the QF to be able to make an informed decision but not so long as to result in an unnecessary mismatch between the commitment and current avoided costs. A minimum three-year notice period, in contrast, would increase the risk of inaccurate avoided cost rates. QFs with

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[19] Johnson Testimony at 4, 13.
[20] *Id.* at 15.

an expiring PPA will receive capacity payments under a new PPA, using a capacity rate that will be based on the Company's capacity position and cost of a new CT resource at that point in the future.

Accurate Price Signals

Q. Please summarize the proposal NCSEA has made with regard to real time pricing in this proceeding.

A. NCSEA witness Johnson testified in favor of real-time pricing during "extreme conditions." He acknowledged the utilities' reply comments on this topic, and agreed that the practical considerations raised by the utilities should be considered, but asserted that those considerations do not justify rejection of his proposal as QF output is already metered on an hourly or sub-hourly basis. He stated that DENC's LMP tariff is not as good a solution as NCSEA's proposal because it is linked to volatile natural gas and other energy markets, and recommended that the utilities should submit proposed plans for implementing this at least 6 months before the next biennial proceeding.[21]

Q. What is the Company's response to witness Johnson's recommendation for real-time pricing and critique of the LMP tariff?

A. Witness Johnson's proposal to implement real-time pricing essentially asks for both long term fixed prices and short term variable prices. QFs cannot, however, have it both ways. His proposal would effectively result in "higher-of" pricing, that is, the higher of the known FP rates and the potentially

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[21] *Id.* at 32-37.

volatile LMP rates for some number of hours during the year. The Company believes this type of hybrid pricing is not reasonable because it is unfair to customers (because it is the customers that ultimately pay for the optionality given to the QF), and because it unecessarily complicates the pricing, administration, and payments to small standard QFs.

Q. What is the Company's response to Witness Johnson's recommendation for the energy rate granularity to be typical-day per month hourly pricing (to be shown as a 12 x 24 price matrix)?

A. As I discuss below, the Company is taking steps to make the QF rates more granular and believes that a path of gradualism is most prudent. Implementing 12 x 24 pricing in this biennial proceeding would add undue complexity when simplicity is more appropriate. This is consistent with Public Staff's reply comments, which stated that "because some months have similar energy price characteristics, [Johnson's proposed] approach may increase complexity without providing significant additional benefits," and that the rate design the Public Staff has proposed, to which the Company has agreed as discussed below, "would provide more granular pricing information to QFs without imposing significant new administrative burdens."[22]

Q. Did any party testify to the Company's rate design in this case?

A. Yes. Public Staff witness Thomas testified that the Public Staff and the Company have discussed modifications to DENC's proposed avoided cost

[22] Reply Comments of the Public Staff at 3 (Mar. 27, 2019).

rate design that are similar to the modifications reflected in the stipulation that the Public Staff entered into with Duke. He noted that the Public Staff and the Company have largely reached agreement on the details of a proposed rate design, and that the Company stated in its reply comments that it would be willing to accept the Public Staff's proposal with certain modifications. He stated that the Public Staff agrees with the Company's proposed modifications – including September as a summer month, and expanding 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).[23]

Q. **Do you have anything to add to witness Thomas' testimony?**

A. While the Commission concluded as discussed in its April 24, 2019 order that the Company's rate design can be decided without expert testimony, I would like to state for the record that the Company agrees with witness Thomas' testimony on this matter. For clarification, the following table presents the Company's currently proposed energy and capacity rate designs as discussed in DENC's reply comments and those of the Public Staff:

[23] Thomas Testimony at 41.

DENC Energy Rate Design

Initial Filing Mon-Sun non-holidays

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
May-Sep																								
Dec-Feb																								
Shoulder																								

REVISED Mon-Fri non-holidays; Sat-Sun off peak all day

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jun-Sep																								
Dec-Feb																								
Shoulder																								

Summer Premium Peak
Summer On-Peak
Summer Off-Peak
Winter Premium Peak
Winter On-Peak(am)
Winter On-Peak(pm)
Winter Off-Peak
Shoulder On-Peak
Shoulder Off-Peak

DENC Capacity Rate Design

Initial Filing Mon-Fri non-holidays

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
May-Sep																								
Dec-Feb																								
Shoulder																								

REVISED Mon-Fri non-holidays

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer On-Peak	Jun-Sep																								
Winter On-Peak(am/pm)	Dec-Feb																								
Shoulder On-Peak	Shoulder																								

Conclusion

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BY MR. DANTONIO:

Q. Mr. Petrie, do you have a summary of your direct and rebuttal testimonies in front of you?

A. (Bruce E. Petrie.) Yes.

Q. Would you please present that now for the Commission?

A. Good morning. My name is Bruce Petrie, and I am the manager for generation system planning for Dominion Energy North Carolina.

Currently, there are 72 solar QFs operating in Dominion's North Carolina service area. This represents approximately 501 megawatts of solar capacity. That total will rise to 691 megawatts when all the QFs with which the company has executed power purchase agreements come online. 691 megawatts significantly exceeds the Company's 2018 average on-peak load of approximately 525 megawatts. My direct and rebuttal testimony in this proceeding support modifications to Dominion's standard offer tariff in order to balance the Commission's goals in these biennial proceedings going forward, encouraging the already significant QF development on the one hand, and protecting utility customers from overpayment on the other.

In my direct and rebuttal testimony, I focus on the Company's proposed redispatch charge related to solar QF's intermittent generation and address the appropriate assumed in-service date for standard offer QFs for purposes of calculating the avoided capacity rate. The Company's redispatch charge represents the first step in quantifying the costs of integrating these large volumes of solar generation into its system, the impetus of which was the Commission's directives in its 2016 avoided cost order and the procedural order in this docket. Generally, the redispatch costs are the additional fuel and purchased energy costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. These costs increase as the intermittency of electricity generation on the Company's system increases. Electricity generation from solar QFs is intermittent, and the redispatch charge helps capture the cost of this intermittency. The Company originally calculated a redispatch charge of $1.78 per megawatt hour, but after discussion with the Public Staff, and in response to comments and testimony filed in this proceeding, the Company modified its modeling in the interest of compromise and is now proposing a redispatch charge of $0.78 per megawatt hour. This modified charge is supported by the Public Staff and takes into account the costs and benefits of solar QF generation.

With respect to the assumed in-service date for standard offer power purchase agreements, I reiterate in my testimony that the purpose of this docket is to develop reasonable avoided cost rates that apply to small QFs that sign a contract during the 2019/2020 biennial period. As the Public Staff agrees, an assumed in-service date in the year following the November 1st biennial filing date for avoided costs is a reasonable, administratively efficient approach that treats existing and new facilities equitably. Alternatives to this accepted approach that have been proposed by NCSEA in this proceeding would add unnecessary complication and give rise to more disputes.

In addition to the redispatch charge and assumed in-service date issues, I address other arguments raised in this proceeding as they relate to the Company. One of these issues is whether innovative QFs that use technology such as battery storage to reduce intermittency should be exempt from the

Company's redispatch charge. I testify that, while the addition of battery storage may potentially smooth the QF output during certain hours, the shape of the megawatt output during the middle of the day, in between charging in the summer morning and discharging in the evening, will still exhibit a considerable amount of volatility and intermittency, and therefore, these QFs should not be automatically exempt from the redispatch charge.

This concludes my summary. Thank you.

Q. Thank you, Mr. Petrie.

And now, Mr. Billingsley, would you please state your name and business address for the record?

A. (James M. Billingsley.) My name is James Billingsley. Business address is 5000 Dominion Boulevard, Glen Allen, Virginia.

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

A. I'm the manager of power contracts and origination for Dominion Energy North Carolina.

Q. And did you cause to be prefiled in this docket, on June 25th of this year, eight pages of supplemental testimony in question and answer form and an Appendix A?

A. Yes.

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

A. I do not.

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

A. Yes, they would.

Q. Mr. Billingsley, did you also cause to be prefiled in this docket on July 11th of this year eight pages of supplemental rebuttal testimony in question and answer form?

A. Yes.

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

A. I do not.

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

A. Yes.

MR. DANTONIO: Chair Mitchell, at this time, I would move that Mr. Billingsly's supplemental testimony and Appendix A and his supplemental rebuttal testimony be copied into the record as if given orally from the stand.

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

(Whereupon, the supplemental testimony and Appendix A and supplemental rebuttal testimony of James M. Billingsley were copied into the record as if given orally from the stand.)

**SUPPLEMENTAL TESTIMONY
OF
JAMES M. BILLINGSLEY
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158**

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

A. My name is James M. Billingsley, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am a Manager of Power Contracts and Origination for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

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

A. I am responsible for the negotiation, origination, and day-to-day administration of the Company's non-utility generation power contracts. A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously filed testimony in this proceeding?

A. No.

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

A. The purpose of my supplemental testimony is to respond to the Commission's *Order Requiring Supplemental Testimony and Allowing Responsive Testimony* issued in this proceeding on June 14, 2019. The Commission's Order requests testimony regarding which avoided cost rate schedule and contract terms and conditions apply when a Qualifying Facility ("QF") adds battery storage to an electric generating facility that has (i) established a legally enforceable obligation ("LEO"), (ii) executed a power purchase agreement ("PPA"), 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.

Q. **Do the Company's Schedule 19 tariffs or PPAs specifically address the scenarios presented by the Commission in its Order?**

A. No.

Q. **In the Company's experience, have any QFs requested to add battery storage to projects that fall into any of these scenarios?**

A. The Company has not received any proposals to add battery storage to a QF in any of these scenarios. Given the lack of substantive discussions the Company has had around adding battery storage to a QF, the Company has not proposed any changes to the Schedule 19 tariffs or PPAs to specifically address this matter in this proceeding.

Q. **What is the Company's overall position on the Commission's question?**

A. The Company's position is that, in all three of the scenarios presented by the Commission, the rates and terms and conditions associated with the current biennial period would apply. This means that if a QF seeks to add battery storage to a proposed or existing facility that established an LEO or executed a PPA in a previous biennial period, even if it has commenced producing power, the QF would be required to establish a new LEO and execute a new

PPA in the current biennial period at current rates and contract terms. In short, the Company does not believe that a QF that has established an LEO, entered into a PPA, or is operating under previously approved avoided cost rates and terms should be permitted to increase its capacity (MW), increase its energy (MWh) production capability, or shift its generation profile under those rates and terms.

Q. Please explain the issues involved and the basis for the Company's position.

A. Allowing a QF that is entitled to rates and terms associated with previous biennial periods to either expand its maximum capacity, energy production, or shift its hours of production under those rates and terms would burden the Company and its customers with newly-obligated overpayments at stale avoided cost rates, in contravention of PURPA's requirement that utilities not pay more than their avoided cost for QF output.

The following table shows the standard avoided cost rates approved in the 2012 Sub 136 and 2014 Sub 140 dockets (based on the Option B peak hours definition), compared to the rates filed in this 2018 Sub 158 docket (based on a more granular peak hours definition).

Rates in cents/kWh	*2012 Sub 136 Rates* Capacity	Energy	*2014 Sub 140 Rates* Capacity	Energy	*2018 Sub 158 Rates* Capacity	Energy
On Peak	8.621 summer 3.323 non-summer	5.962	6.421 summer 2.475 non-summer	5.124	2.857 summer 2.884 winter 0.528 shoulder	3.211
Off Peak	N/A	4.824	N/A	4.314	N/A	2.523

As this data shows, the rates established in the 2012 and 2014 dockets are generally much higher than the current forecast of avoided costs. And, as has been discussed extensively in previous avoided cost proceedings, the result of this disparity is that the Company is committed to rates under long-term contracts entered into in previous biennial periods that greatly exceed current avoided costs.

The addition of batteries will enable QF project owners to shift energy deliveries from lower priced off-peak hours to Option B on-peak hours that are higher priced and include capacity payments, exacerbating the overpayment burden the Company and its customers already bear under these PPAs. This result contradicts the requirement of PURPA that purchases at avoided cost rates be fair to both QFs and the utility (and its customers).

Q. What is the potential cost exposure to the Company and its customers of the addition of battery storage under previous rates and terms?

A. The table below shows the estimated additional costs to the Company if the QF owners that signed PPAs during the 2012 and 2014 avoided cost dockets installed 4-hour battery systems at a MW level of 40% of the project nameplate rating. For purposes of this illustration, the table assumes a 5 MW solar PPA would install a 2 MW / 4-hour battery system. In addition, again for illustration, the Company has assumed an average remaining term for these PPAs of 10 years and has allocated non-standard negotiated PPAs between the Sub 136 and Sub 140 biennial periods based on the relative percentage of negotiated PPAs executed in each period.

	Nameplate MW	Incremental Cost per Year *(millions)*	Remaining Term *(Years)*	Incremental Cost Over Reminaing Term *(millions)*	
Sub 136	362	$6.1	10	$61.1	
Sub 140	328	$3.7	10	$37.2	
Total	690	$9.8		$98.3	
				$9.8	**10%**
				$49.2	**50%**

The illustration shows that if 10% of the contracted MWs add 2 MW / 4-hour batteries, the Company would pay an additional approximate $9.8 million over the assumed 10 year period. And if 50% of the contracted MWs add batteries, the Company would pay an additional approximate $49.2 million over the 10 year period. Again, the Company and its customers would bear these extra costs in addition to the already above-market prices for capacity and energy associated with these older PPAs. For example, the effective average cost of a 2012 vintage contract (Sub 136 QF) in the scenario above would increase from $73/MWh to $86/MWh.

Q. Does the fact that almost all Sub 136 and Sub 140 QFs elected Option B rates support the Company's position?

A. Yes. Nearly all of the solar QFs that executed PPAs with the Company during these biennial periods elected the Option B peak hours definition and pricing. However, the Option B definition no longer necessarily represents the Company's highest marginal energy cost hours, as evidenced by the Company's filings in this docket that have proposed, in compliance with the Commission's directives in the Sub 148 proceeding, narrower higher-value peak periods to incentivize QFs to produce during these times of day.

While the Company adopted the Option B hours definition into its standard offer in the Sub 136 proceeding, the Option B definition of on-peak hours was developed in 2002 (Docket No. E-100, Sub 96) based on the load and marginal cost patterns on Duke's system at that time. For example, under Option B, in the summer months the weekday on-peak period is from 1 to 9 pm. Suppose that a QF owner that adds batteries to its facility charges the battery system from 6 to 11 am on summer days, and then discharges the battery from 5 to 9 pm as the solar output is decreasing. These incremental on-peak energy deliveries during the evening will receive approximately $11/MWh more for energy than if the QF delivered the energy during the morning off-peak hours, plus $86/MWh for capacity, even during the evening hours 7 to 9 pm on a summer weekday when capacity has less value (relative to output from 2 to 6 pm). Such a result would not only inequitably burden the Company and its customers with additional above-market payments, but would not be appropriate given the recent movement toward more granular rate design to incentivize QFs to develop projects to sell during a narrower, higher-value set of hours.

Q. Are there any other reasons for the Company's position?

A. Yes. QFs that established LEOs, executed PPAs, or commenced delivering power under the Sub 136 and Sub 140 biennial periods did so based on the QF's representations to FERC in its QF self-certification (as stated at the previous version of the LEO form), to the Commission in CPCN applications or Reports of Proposed Construction, and to the Company. A QF should not be permitted to expand its scope beyond what was originally agreed upon through a previously established obligation or PPA relationship to either sell more output or shift output in a manner not contemplated at the time that relationship was established, or both.

Q. Given the Company's positions outlined in your testimony, does the Company intend to propose revisions to its standard offer rate schedules and contracts proposed in this proceeding to address this topic, similar to Duke's proposals?

A. Since the Company has not directly experienced the scenario this supplemental testimony addresses, the Company has not prepared and vetted revisions to its standard offer rate schedules and contracts at this time. The Company plans to further consider this topic in the next biennial proceeding.

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS
OF
JAMES M. BILLINGSLEY

James M. Billingsley joined the Company in 2005 as an Associate Financial Analyst in the Financial and Business Services – Generation Consolidated Department. Since then he has held various financial roles within the power generation, natural gas transmission and distribution, and corporate financial analysis areas of the Company. In 2014, Mr. Billingsley was promoted to Manager of Energy Infrastructure Financial Management and Commercial Support. In October 2017, he assumed his current position of Manager of Power Contracts and Origination. In his current role, Mr. Billingsley is responsible for the negotiation, origination, and day-to-day administration of the Company's NUG power contracts.

Mr. Billingsley graduated from the University of Virginia in 2005 with a Bachelor of Science degree in Commerce with concentrations in Finance and Management.

Mr. Billingsley has previously presented testimony before the State Corporation Commission of Virginia.

**SUPPLEMENTAL REBUTTAL TESTIMONY
OF
JAMES M. BILLINGSLEY
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158**

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

A. My name is James M. Billingsley, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am a Manager of Power Contracts and Origination for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

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

A. I am responsible for the negotiation, origination, and day-to-day administration of the Company's non-utility generation power contracts.

Q. Have you previously filed testimony in this proceeding?

A. Yes, I filed supplemental testimony in this proceeding on June 25, 2019.

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

A. The purpose of my supplemental rebuttal testimony is to respond to the supplemental testimony filed by Public Staff witness Dustin R. Metz,[1] North Carolina Sustainable Energy Association ("NCSEA") witness Tyler H.

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[1] Supplemental Testimony of Dustin R. Metz ("Metz Supplemental").

Norris,[2] Southern Alliance for Clean Energy ("SACE") witness Devi Glick,[3] and Ecoplexus, Inc. ("Ecoplexus") witness Michael R. Wallace[4] filed in this proceeding on July 3, 2019.

Q. Please summarize the Company's position on the question posed by the Commission in its June 14, 2019 Order as described in your supplemental testimony.

A. In my supplemental testimony, I presented the Company's position that in all three of the scenarios presented by the Commission (a QF that either (1) has established a LEO only, (2) executed a PPA, or (3) is currently operating, and is seeking to add battery storage to its facility), the avoided cost rates and terms within the current biennial period would apply to the entire facility. The primary reason for this position was the risk of burdening the Company's customers with increased costs if existing QFs were allowed to install batteries and continue to receive stale, out of market avoided cost rates for the generation from the entire facility (i.e., the existing QF plus the battery).

Q. Do any of the Public Staff or intervenor witnesses agree with the Company's position as stated in your supplemental testimony?

A. Yes, in part. Public Staff witness Metz, NCSEA witness Norris, and Ecoplexus witness Wallace all testified that it is reasonable for the output associated with battery storage that is added to an existing QF to be eligible

[2] Supplemental Testimony of Tyler H. Norris ("Norris Supplemental").
[3] Supplemental Testimony of Devi Glick ("Glick Supplemental").
[4] Supplemental Testimony of Michael R. Wallace ("Wallace Supplemental").

only for the then-current avoided cost rates.[5] However, they also testified that the existing solar generation facility should continue to receive the avoided cost rates provided under its existing PPA.[6]

Q. Did any of these witnesses testify to the risk of overpayment in this scenario that you described in your supplemental testimony?

A. Yes. Witness Metz testified that the avoided cost rate schedules and rates for energy and capacity established in prior avoided cost proceedings no longer reflect each utility's current avoided costs and it would not be fair to pay QFs for "additional energy" at stale avoided cost rates.[7]

Q. What is your response to the positions of witnesses Metz, Norris, and Wallace on the rates that should apply to the existing solar generation facility?

A. As I stated in my supplemental testimony, the Company has not received any proposals from QFs to add battery storage to their facilities under the scenarios that are the subject of the Commission's request, and the Company's experience with battery storage generally is very limited at this point. Given this lack of experience and the short amount of time available to consider these issues in this proceeding, I believe the Company's original position on this issue was a reasonable one.

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[5] Metz Supplemental at 5; Norris Supplemental at 27-28; Wallace Supplemental at 5.
[6] Metz Supplemental at 5; Norris Supplemental at 28; Wallace Supplemental at 5.
[7] Metz Supplemental at 5-6.

The Company has, however, continued to consider these issues in the days since my supplemental testimony and the testimony of these witnesses was filed. Based on this continued consideration, the Company believes that allowing the existing solar generation facility to continue to receive the original rates for which it was eligible, while applying the current rates to the output from the battery addition, appears to be a reasonable approach to the Commission's question. That said, I agree with witness Metz that there are number of technological and commercial challenges that would likely arise with the implementation of battery storage at existing QF sites.[8] I believe that these issues would need to be thoroughly studied and addressed before this "compromise" approach could be fully implemented.

Q. You mention the Company's lack of experience with QFs proposing to add battery storage. Is the Company taking any steps to better understand battery storage generally?

A. Yes. Pursuant to 2018 Virginia Senate Bill 966, the Grid Transformation and Security Act, the Company is in the early stages of pursuing a battery storage pilot that will increase our understanding of and experience with batteries and any benefits, costs, or challenges associated with this technology. As NCSEA witness Norris stated in his testimony, battery storage remains a nascent technology,[9] but the Company is taking steps to increase its knowledge and understanding on the topic.

[8] Metz Supplemental at 15-16.
[9] Norris Supplemental at 30.

Q. Witnesses Metz and Wallace recommend working groups to address the various technological and commercial challenges associated with adding battery storage to QFs.[10] Would DENC be willing to participate in such a working group?

A. If the Commission found it to be appropriate, yes. However, I recommend that any timelines or milestones associated with such a working group provide sufficient time to thoroughly consider these complex issues.

Q. Would the addition of battery storage alleviate the difficulties of integrating large volumes of distributed solar generation onto the Company's system, such as the re-dispatch costs that the proposed re-dispatch charge is intended to address?

A. Potentially to some extent, but this issue is addressed by Company witness Petrie's rebuttal testimony.[11]

Q. What is your response to interveners that argue that the QF should be allowed to make reasonable modifications to its facility?[12]

A. The Company understands that QFs need to perform various maintenance activities to ensure the ongoing operation of the facility. Therefore, the Company would generally agree that QFs should be able to make modifications where equipment is replaced with like-kind equipment to maintain the original design and capabilities of the facility.

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[10] Metz Supplemental at 19-20; Wallace Supplemental at 9.
[11] Petrie Rebuttal at 8-9.
[12] Glick Supplemental at 5; Norris Supplemental at 19-20; Metz Supplemental at 9-11.

Q. What is your response to NCSEA witness Norris' critique of the Company's position that a QF should not be permitted to expand its scope beyond what was originally agreed upon through a previous LEO or PPA to either sell more output or shift output in a manner not originally contemplated?[13]

A. Witness Norris may have over-analyzed my statements on this topic. I was not making a legal argument regarding the enforceability of representations that a QF makes in FERC or Commission filings. I was simply noting that, in addition to the specific overpayment concern with paying for new added battery output at outdated rates, the Company also believes as a general principal that a QF should not remain eligible for outdated avoided cost rates for significant modifications it makes to its facility beyond what was originally contemplated by the Company's interconnection studies and the original PPA. This belief is consistent with the modified position I discuss above, that while it may be reasonable for the existing or committed solar QF to continue to receive its original rates, the QF should receive current rates for output from a battery that is added to the facility.

[13] Norris Supplemental at 25-27.

Q. What is your response to the testimony of SACE witness Glick that as long as a QF discharges power onto the grid consistent with PURPA and its Interconnection Agreement and 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?[14]

A. With regard to the output from the battery, I disagree with witness Glick for the reasons provided in my supplemental testimony.

Q. What is your response to witness Glick's rationale that the rates to QFs would not change, only total payments?[15]

A. Witness Glick's testimony demonstrates the Company's exact concern with the argument that existing QFs that add battery storage should receive legacy avoided cost rates for that battery's output. Witness Glick is correct that in that scenario, the rates would not change and total payments to the QF would increase. The reason the payments would increase is that they would be based on stale rates (and misalignment of peak hours) that no longer represent the Company's avoided cost or premium peaks. Those costs would then ultimately be shouldered by customers, as the costs customers will avoid today would be significantly less than the contractual rates paid under Sub 136 and Sub 140 contracts.

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[14] Glick Supplemental at 4-5.
[15] *Id.* at 7.

Q. What is your response to witness Glick's recommendation that the Company follow all of her outlined suggestions on pages 14-15 of her testimony?

A. To the extent that any of witness Glick's recommendations would apply to the Company, I disagree with those recommendations for reasons already previously mentioned in my supplemental and this supplemental rebuttal testimony.

Q. Does this conclude your supplemental rebuttal testimony?

A. Yes, it does.

BY MR. DANTONIO:

Q. Mr. Billingsley, do you have a summary of your supplemental direct and supplemental rebuttal testimonies in front of you?

A. I do.

Q. Would you please now present that for the Commission?

A. Good morning. My name is James Billingsley, and I am the manager of power contracts and origination for Dominion Energy North Carolina.

My supplemental and supplemental rebuttal testimony responds to the Commission's request for testimony addressing which avoided cost rate schedule and contract terms and conditions apply when a QF adds battery storage to its facility when the QF has; one, established a legally enforceable obligation; two, executed a power purchase agreement; and/or three, commenced operation and sale of the electric output of the facility to the relevant utility, and also responds to other parties' testimony on this question.

In my supplemental testimony, I state that, in all three scenarios, the rates and terms and conditions associated with the current biennial period would apply to the entire facility. I explain that allowing QFs that add battery storage to their facilities to continue to receive its previously established rates for the new battery's output could require the Company to pay an additional tens of millions of dollars and would be inequitable to the Company's customers.

In my supplemental rebuttal testimony, I explain that, based on additional time to consider the question and the testimony of other parties, the Company believes that the compromise position proposed by the Public Staff could also reasonably address the Commission's questions. The compromised position that the Company would be willing to consider would allow existing QFs that add battery storage to their facility to continue to receive the rates for which the original facility was eligible for the original facility's output, and to receive current rates to the output from the battery addition to the original facility. I caveat this by stating that the Company is in the early stages of its experience with and understanding of batteries and the costs and challenges associated with the technology. In order for the compromised position to be effectively implemented, the Company would need to better understand the technological and commercial challenges with this technology, which could be achieved through a working group or similar effort.

This concludes my summary. Thank you.

Q. Thank you.

MR. DANTONIO: The witnesses are now available for cross examination.

CROSS EXAMINATION BY MR. SMITH:

Q. Good morning. My name is Ben Smith, regulatory counsel for the North Carolina Sustainable Energy Association, or NCSEA. I just have a few questions. And I know this was addressed, but I think it was kind of pushed back and forth.

Is the redispatch charge going to be a line item charge or is it a decrement to the avoided cost? And I apologize. These are mostly to you, Mr. Petrie, but either can answer.

A. (Bruce E. Petrie.) Right. The rate filing that we made last November, it -- the $1.78, we -- the way it was written into the tariff, it was -- it would be a subtracter from the energy rate. But as it came up in testimony, if the Commission desires it to be a separate line item, accounted for separately, we can do that, but the way it was lined up -- initially proposed, it was a subtracter from the energy rate.

A. (James M. Billingsley.) And I would just add that really the main driver for the subtracter from the rate was just ease of administration from a contract's perspective. I think it's been recorded that we have several QF contracts, and just from an administrative perspective, having one less line item on the invoice was really our main driver for suggesting that.

Q. Thank you. Mr. Petrie, I'm going to go to some questions from your direct testimony. I understand Dominion's position has evolved since the direct testimony was filed, so to the extent I'm characterizing something that's evolved, please correct me.

Your refer, on page 6 of your direct testimony, to the redispatch charge as complimentary to Duke's proposed integration charge and say they analyze two different aspects of the resource intermittency.

Can you explain what you mean by that?

A. (Bruce E. Petrie.) Yes. The -- so we -- we looked at the problem in one way, and Duke looked at it in another way. When you think about integration charges, there is two -- in our view, there is two major components to it. There is the redispatch cost. Generators have to move up and down to accommodate the intermittency of solar or wind generation. And then there is the aspect that Duke looked at, which is the operating reserves or ancillary services aspect of it, where you may have to carry extra spinning or operating reserves or regulation to accommodate -- or to keep the same level of reliability that you would have had in a system without solar. So it's -- so we looked at it from two different angles. That's why we characterized it as being separate -- separate and distinct.

Q. Thank you. The word that caused us concern is the word "complimentary," and that -- you know, amongst other words, but that was a big word, because there is a little bit of uncertainty there.

When you say "complimentary," does Dominion intend to file integration charge at a later date similar to what Duke's filed based upon their premise?

A. The Company -- we do -- we do expect to do a more comprehensive ancillary services charge or integration charge at a future date. It's not -- it's not going to be included in the 2019 IRP, but I think, in our reply comments to the North Carolina IRP this year, we -- our goal is to look at it and to make progress on a more comprehensive integration study for the 2020 IRP.

Q. I appreciate that. Would it be fair that -- shouldn't the intermittency issues -- understanding that they are two issues that are being addressed, but shouldn't the overall cost be holistic? Shouldn't that charge include everything? And maybe you are saying that, in the future, it will.

A. Yeah. I think the -- we haven't scoped out the study yet, but the way we looked at it was -- and these integration charges are complicated. There is -- what we decided was to look at the more manageable problem first. Just with the modeling capability that we do have, we decided to look at the -- do the hourly modeling and look at the redispatch costs and -- versus what Duke did. You know, they attacked the modeling -- the subhour modeling of -- that comes with trying to figure out, okay, how much extra operating reserves do we have to carry to keep the same level of reliability on the system.

So we -- our approach was to -- let's -- let's attack this smaller problem first. And the reason we did it that way was for the 2018 IRP we -- this redispatch study, it was done in Q1 of 2018, and it was done in preparation for the 2018 IRP. So that study was done using the PLEXOS model early in 2018.

It was done for the purposes of the IRP. So because of all -- because of the numerous connections between IRP and avoided cost rates, we said, okay, we got this $1.78 charge that was used in the IRP, because of the -- you know, for consistency between IRP and avoided cost we said, okay, let's also use it for the avoided cost energy rates. But, anyway, that's the long way of saying we're gonna -- we are planning on doing a more comprehensive study later on in the future that should capture both redispatch costs and the cost of ancillary services.

Q. Thank you. That leads me to my next question. And I apologize, I don't mean to simplify this or otherwise mischaracterize what's actually going on, but aren't there overlapping concerns between the operating reserves issue and the, sort of, load following issue that Dominion's characterized when describing the redispatch cost? And I guess what I'm getting to is, they -- when you use the word "complimentary," I think one plus one equals two, but when, in fact, it might not end up being one and one equal two, it might be a combination of the two equals whatever; do you see what I'm saying?

A. Yes, yes. As far as -- we used the word "complimentary" because there are a lot of connections between the two. We know what we did, and the way we did our modeling was to try to quantify the cost -- the extra cost on the system to -- caused by this intermittency. As far as -- yeah, okay, bear with me a minute. Yeah. When you say -- when you say one plus one equals two, if you are thinking could you take the -- let's say the settled $0.78 for the redispatch charge and add that to Duke's $1.10, you know, the intention was never to do that. We are gonna do our own study, but -- because I don't know exactly how Duke did their study and how the SERVM model works. I don't know if there is some element of redispatch costs that are -- that would be buried in Duke's study. I don't -- I can't speak to that, but I can say that, for our study, we focused on the redispatch costs and didn't concern ourselves with the change in operating reserves or ancillary services.

Q. And so I guess the final follow-up, and I will move off of this, is that Dominion doesn't intend to count anything double? They are not gonna say it costs this much that's in the redispatch cost, and in a future integration cost -- do you see what I'm asking?

A. Yeah, no. There is no intention to double count. We are -- we took this small step in the right direction to try to quantify the redispatch cost. At a future date, we are gonna do a more comprehensive study that -- I think the intent would be to make it, you know, all inclusive, to include redispatch costs and ancillaries, but that's -- that will be determined when that study is framed up.

Q. Thank you. Just a couple more questions for you, and then I have a couple for Mr. Billingsley.

On page 14 on your direct testimony you say the redispatch charge represents the first step in quantifying cost of integrating these large volumes of solar generation into the system. Realizing that in your summary you talked about how Dominion did take into account the benefits of solar, and NCSEA appreciates that, I guess my question is, going forward, when you talk about the first step, is it gonna be -- are you going to continue to evaluate benefits of solar and also benefits of added ancillary services and end storage to the system?

A. That's -- that's the intent. We're gonna do this additional modeling work to quantify the solar integration costs. As far as -- as far as some of the other benefits that Witness Beach and Witness Johnson addressed, like avoided T&D costs or market price suppression, we don't -- the Company hasn't commissioned a study to look at avoided T&D costs. I can't speak to whether the Company will do that. All I can say, from what -- and we're not the experts on the wire side of the business, so all I can say is that, from what we have seen with the concentration of solar in northeast North Carolina and our relatively small service area there, that it's more likely to be an extra cost versus an avoided cost because of the amount of solar concentrated in that area. The Company hasn't commissioned a large T&D study at this point, but we'll -- our intent is to certainly weigh and quantify the cost and the benefits to the solar generation.

MR. DANTONIO: Mr. Smith, just to clarify, did you say 14 -- page 14 of Mr. Petrie's direct testimony, or were you referring to his rebuttal?

MR. SMITH: I don't have written direct. I assumed it was direct, based upon my prior question. If it was rebuttal, I apologize.

MR. DANTONIO: I think so, just to --

MR. SMITH: I apologize.

MR. DANTONIO: No worries.

MR. SMITH: Thank you for correcting me.

Q. Last question on this topic:

Does Dominion have any plans to, sort of, work with solar developers or third-party entities in incentivizing grid-neutral or grid-beneficial qualified facilities going forward?

A. Could you rephrase that? What do you mean by grid-beneficial?

Q. Well, if -- from our perspective, a qualified facility that provides firm generation. And I realize that there are differing opinions as to how firm a solar-plus-storage facility can be on the grid, but assuming benefits, does Dominion intend to work with outside entities, which I believe you have so far in this docket, and that's sort of where this question comes from.

Do you intend to continue to work with outside entities to sort of help incentivize projects within your territory that will be beneficial or at the very least not be costly to Dominion's territory?

A. Yeah. I think the short answer is yes, we are willing -- we are willing to work with these different suppliers. We obviously want reliable power for -- on our system. It's a pretty hot topic right now, what's the value of solar plus storage, where there's -- you know, it's a pretty -- it's being discussed at various PJM committees, and we're -- to the extent we can -- you know, we're gonna continue to keep analyzing this to see what is the value of solar, what is the value of solar plus storage. That's certainly our intent.

Q. Thank you. Mr. Billingsley, I just have four questions for you, and then I'm done.

You testified, on page 7 of your June 25th supplemental testimony, that, in your view, a qualified facility should not be able to deviate from the representations made in its original FERC form 556 and its CPCN application; is that right? I don't know that that's something that -- how did you come to that position?

A. (James M. Billingsley.) Yeah. And I think you maybe kind of alluded to it. I think NCSEA Witness Norris may have, kind of, commented on that specific Q&A, and I think, in my supplemental rebuttal, I tried to address concerns. I certainly don't pretend to be a lawyer. My intent of that Q&A was not to make a legal argument of what a QF can and can't do with its QF filing or the CPCN. I was just trying to stress the point that I think had been raised previously in discussions with Duke, that, you know, our company entered into these PPAs with an understanding of what those facilities would be. You know, we are talking about PPAs that are vintage 2013, '14, '15. You know, energy storage was not contemplated. So I just think that that's something that the Commission should consider, given that energy storage was not contemplated at that time.

Q. So it would be fair to say that Dominion believes the general principle of QF shouldn't be able to change its configuration from what was described in the CPCN or the form 556, but that's not based on any legal theory?

A. Correct. I think there is some unique circumstances that we are facing in this hearing today, given the solar-plus-storage question to -- adding that to existing contracts.

Q. Are you aware that QFs frequently amend their form 556s or CPCNs to reflect changes to the information included in the form 556 or the CPCN application?

A. I am. We get notices of those through our legal team frequently, changes of ownership. I mean, pretty benign changes, what I would say. Ones that have no impact, pretty much, to the existing PPAs and contracts that we have.

Q. But some of those changes include information about the electrical configuration of the facility, not -- that doesn't increase the nameplate capacity, correct?

A. That certainly could be.

Q. And are you aware that amending a form 556 or a CPCN in this way is not -- has not historically caused the QF to lose its LEO?

A. I will take your word for that.

MR. SMITH: No further questions.

CROSS EXAMINATION BY MS. BOWEN:

Q. Good morning, gentlemen. My name is Lauren Bowen. I'm with the Southern Environmental Law Center here today on behalf of Southern Alliance for Clean Energy. I have just a couple of questions for you, Mr. Billingsley, and then my colleague has a few questions for you, Mr. Petrie.

So, Mr. Billingsley, in your testimony -- and I believe it's page 6, if you want to reference it. You probably don't need to, but in your testimony --

A. (James M. Billingsley.) Okay.

Q. Sure. You state that almost all Sub 136 and Sub 148 QFs elected the option B peak hours definition and pricing; do I have that right?

A. That's correct.

Q. Okay. And you go on to say that option B definition no longer necessarily represents the Company's highest marginal energy cost hours; do I have that right as well?

A. That's correct.

Q. Okay. And then you also testified that, in the Company's filings in this proceeding, you were proposing narrower high value peak periods to incentivize QFs to produce during those times of day when the Company is currently -- those times currently represented by the Company to be the highest marginal cost hours. I know that was long, but did I get that right?

A. I believe you got that right.

Q. Great. Okay. Great. And then -- so my question is with -- based on that, it sounds like some of your concerns would be addressed if the current or the existing QF's addition of battery storage was configured to produce energy during those newly identified peak periods that have been proposed in this proceeding; do I have that right as well?

A. Could you say it one more time? I'm sorry. I apologize.

Q. Yeah, yeah. Absolutely. So would some of your concerns or any of your concerns be alleviated if the existing QFs were incentivized to produce energy during the new peak periods that have been proposed by the Company?

A. Potentially, yeah. I think we have -- between Mr. Petrie and myself, we try to make it clear in our testimony that the new -- as you stated, the new peak hours or peak pricing periods are the signal when the Company would, you know, most desire some of this QF generation. So I think that makes sense.

Q. Okay. Great. And then you have indicated, in your summary and in your testimony, a willingness on the rate side, that it would cause rates to further discuss NCSEA and Public Staff's recommendation regarding the storage -- addition of storage being subject to the new avoided cost rates; do I have that right?

A. That's correct.

Q. The Company's willing to discuss that, okay.

And would you also be willing to discuss the peak hours issue, in particular, as well?

A. I assume so. I mean, I think that would be part of the discussion. The hours we proposed -- I think with the compromised position, as I understand it, is, you know, the -- the -- if the various technological and commercial challenges can be overcome, and while I think I made it clear this is fairly new to the Company, they seem to be significant. But if we could work through those, and the battery was being charged current avoided cost rates, then I assume those rates would fall under these new proposed, you know, premium price windows. So if generation was during those times, they would be getting that rate, et cetera.

Q. Got it. And you've testified that, to date, the Company has not had any QFs approach them to add battery storage to existing projects?

A. That's correct.

Q. Okay. And you have requested, if we do have a working group, to just make sure there is enough, sufficient time to address these issues since they are complex?

A. That's correct. I think, you know, in the various testimonies, I think Public Staff Witness Metz mentioned working group. I think it was maybe Ecoplexus Witness Wallace talked about a working group as well, and I just wanted to put that comment out there, while I appreciated, I think, the witness putting some suggested timelines, given my very high-level knowledge of the challenges that, you know, all parties would be encountering, that timeline seemed a little aggressive, in my personal opinion. I think it was kind of, like, 30-day milestones. And just in the Company's experience, not only in North Carolina and Virginia, working groups, they are great, but they involve lots of stakeholders, lots of coordination of schedules, and we just want to make sure we don't rush through this and we thoroughly consider the issues.

Q. You could work together on a schedule?

A. I would certainly hope so.

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

CROSS EXAMINATION BY MS. HUTT:

Q. Good morning, Mr. Petrie. My name is Maia Hutt. I'm an attorney at the Southern Environmental Law Center. I'm here on behalf of SACE.

A. (Bruce E. Petrie.) Good morning.

Q. So my understanding is that Dominion has agreed to revise the proposed redispatch charge down to

$0.78 per megawatt hour in accordance with the Public Staff and SACE's recommendations; is that right?

A. That's right.

Q. And is Dominion proposing that this revised charge would apply prospectively, like Duke's proposed solar integration charge, or would it apply to QFs that currently have PPAs?

A. It would be prospectively.

A. (James M. Billingsley.) Yeah. From a contracting perspective, we are not looking to add that to existing PPAs.

Q. Okay. So it would only apply once the PPA has expired and they go to --

A. Correct. So when PPAs -- going forward, or to the extent there is a renewal in the future, then that charge would be applied in the renewed contract.

Q. Okay. Great. So I understand from your summary that your position is that adding a battery to a solar QF will not, in all circumstances, resolve volatility and intermittency, and, therefore, QFs should not automatically be exempt from the charge; but do you agree that there are some circumstances where adding the battery could address those concerns?

A. (Bruce E. Petrie.) Are you on my direct or rebuttal?

Q. I'm actually just responding to your summary.

A. Okay. And your question is are there some circumstances where the intermittency and volatility could be reduced?

Q. Yes.

A. The short answer is yes. It depends on how -- it depends on how the battery is operated. If it's -- if it's straight up used as an energy arbitrage to charge in the morning and discharge in the evening, to take advantage of that on-peak/off-peak spread, it's probably not going to do a whole lot of reduction of intermittency, but if the battery is operated -- and from what I read, I guess they are pretty sophisticated, the control systems. If it's operated to actually smooth the output, if the QF wanted to operate that way to avoid a $0.78 per megawatt hour redispatch charge, my understanding, that's conceivable.

Q. Okay. So just to confirm, you agree that there are some conceivable circumstances where it would be inappropriate to charge this redispatch charge to solar QFs that have battery storage?

A. Correct.

Q. Okay. Thank you. No further questions.

CROSS EXAMINATION BY MS. CUMMINGS:

Q. Hi. I'm Layla Cummings with the Public Staff. I just have one question for Mr. Petrie.

Do you expect, over time, that the -- that Dominion's redispatch charge, as currently calculated, will go down with increasing penetration?

A. (Bruce E. Petrie.) That's a good question. The -- when we -- the redispatch charge, like I was explaining earlier, it's just a -- it's a subset of a larger integration study. So when we get to do the more comprehensive study, it's hard to tell whether, when we have got an all-in study that accounts for redispatch costs and the potential for having to carry more operating reserves, it's hard to tell whether that number is going to be higher or lower than the $0.78.

Q. But the current way it's calculated, could you forecast at all, maybe due to sales and to PJM, the participation at market, that charge could go down?

A. It could go down.

Q. That's all. Thank you.

CHAIR MITCHELL: Redirect?

MR. DANTONIO: No redirect.

CHAIR MITCHELL: Questions by the

Commission?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. I just want to be absolutely crystal clear I know where we are as we sit here today. As we sit here today, based on the dialogue you had with counsel, as I understand it, you are not prepared today to offer any proposed operating protocols for storage that would entitle a QF to an exemption from the redispatch charge; that's something that will come out of the working group? Do I understand you correctly? I just want to know where we are in the process. I had the same question of Duke, because they are in a different place with different moving parts, and I want to know where you are.

A. (James M. Billingsley.) Sure.

Q. Did I get it right?

A. Yeah. I think that's a fair character --

Q. So, as we sit here today, you don't have anything to put forward by way of an operating protocol that would entitle someone to an exception?

A. Right. Just a little background, I think it's clear from my testimony, the Company is exploring battery pilots. We are at the early stages. So, at this point, we are not at that stage yet.

Q. Okay. That's what I thought. I just wanted to confirm. Thank you.

A. You're welcome.

CHAIR MITCHELL: I have a question.

EXAMINATION BY CHAIR MITCHELL:

Q. Mr. Petrie, I think this is for you, but both y'all feel free to answer. Can you help us understand, from a system operations standpoint, what poses a bigger challenge for the Company, the duck curve phenomenon that we've heard a lot about in previous cases or the intermittency phenomenon that's caused by the increasing integration of variable generation like wind and solar? What is -- which is more difficult or challenging for the Company to address, to the extent that one is more problematic than the other? So just talk briefly about that, if you can.

A. (Bruce E. Petrie.) Okay. I'm not sure -- I can talk a little bit about the redispatch charge, but I'm not sure you were -- you wanted compare that to something else, but as far as the redispatch charge goes, what happens is, when -- during the course of the operating day we commit to dispatch units to serve load, and in the past, it's -- you know, there is about 2 million customers on the system. So, in the past, the load variability was made up of customer variations. So the load would jiggle up and down, you know, every second. And we've got this fleet of generators that dispatch up and down to meet -- to keep the system frequency at 60 hertz and to keep the load and supply in balance.

So what happens is, when you add -- when you add solar, large volumes of it, what it does is it amplifies these second-to-second variations in the load, because the behind-the-meter generators, they are located on the distribution system. They don't -- they are not like a typical generator where they are out -- like a dispatchable generator, where the output is telemetered to PJM, and they are not getting a dispatch signal, they are not load following. They just -- they put out what they put out. And whenever cloud comes -- cloud cover comes over, it -- what it -- it manifests itself in an amplified load variation. That's what -- that's what the system operators see. In fact, at PJM, some of these -- there is various committee meetings. They have noticed in New Jersey and North Carolina some of these substations are -- they are not -- instead of being load busters anymore, now they are injecting grids. They are injecting megawatts onto the grid. So there is a surplus of generation in this northeast North Carolina pocket, and that's -- PJM is seeing that in the data that they see. So there is some committee activity looking at that.

But what happens is, because of this amplified variability and the minute-to-minute load, the dispatchable generators have to work harder to keep the system in balance. So you've got certain generators that back down from their most efficient operating state. So they are spending more time at a lower operating state where they are operating less efficiently, and we've got maybe some different dispatch patterns on combustion turbines, more startups. So the rest of the fleet is having to dance up and down to pick up the slack from the intermittency that can come from large volumes of solar. I don't know if that was exactly what you were looking for.

Q. That's helpful. And I guess just to follow up, you know, my -- you just said that the rest of the fleet has to dance up and down to respond to the solar as the solar creates variability on a system. And so, I mean, my sort of -- having listened to the testimony that's been provided over the past several days in this room, my question is, to the extent we get to the point where batteries become part of the solar facilities that are interconnected on our systems, are they more valuable to the system from a smoothing standpoint, if they are interconnected to smooth the variable -- this variability phenomenon, are they -- or is the energy shifting a more valuable contribution to the system? Because, at least as I understand it, and you tell me if I'm misunderstanding something, in your opinion, you know, the shifting might go to this duck curve phenomenon that we are experiencing or that we seek to avoid. So that's really my question, and, you know, if you are not prepared to answer that now, that's fine, but I just wanted --

A. I can give you my opinion on it. As far as, yeah, the batteries are certainly a really hot topic right now. There is a lot of industry activity, reports are coming out. The North Carolina -- the State University report, Virginia has a report on energy storage. So it's a really hot topic. FERC -- I think it was FERC Order 841 saying that RTOs have to amend their market rules to enable energy storage to participate in these various rules -- various markets. But as far as, you know, how could batteries provide value, they could -- in my view, the bigger value is this arbitrage between on-peak and off-peak energy. If you could -- and the energy storage concept is not new. We've had Bath County for 30 years. It's -- where we pumped the water up the hill at night, and then it flows down the hill -- down the pipe during the day. So it's a load at night and a generator during the day. The battery storage is the same thing.

In my view, with the -- the bigger value is this arbitrage between on-peak and off-peak, and that -- say there is a $10 spread between $25 off-peak and $35 on-peak energy, you could arbitrage that price spread. That spread, in my view, is going to be more valuable than the smoothing effect. If the ancillary service charge -- or the solar integration charge is roughly $1 or $2 a megawatt hour, why would somebody give up a $10 energy spread to try to avoid a $2 ancillary service charge?

The other benefit that can come from solar is -- or from batteries is the capacity benefit. If you can -- it starts to look more like a dispatchable generator. Solar only is you get what you get on the hourly output, but solar plus battery, it starts to look and feel more like a dispatchable generator. You can -- as long as you've charged it smartly, you can have a battery ready to discharge at 7 a.m. on a winter -- on a cold winter morning, or 5 p.m. on a hot summer afternoon. So it starts to look more like a dispatchable generator.

Q. Thank you, Mr. Petrie. I appreciate that.

CHAIR MITCHELL: Commissioner Brown-Bland.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Petrie, so is it correct that the units on automatic generator control primarily cover frequency now; is that correct? So that units that are not on automatic generator control, they are part of the problem and not part of the solution?

A. (Bruce E. Petrie.) Well, when you say -- you can have -- there is a subset of units that are on AGC, and they are getting a -- they are getting a signal every couple of seconds, and they adjust their output up and down, and that's helping to keep the system frequency at 60 hertz. Then there is other dispatchable generators that are not -- that are not on AGC, but they are ramping up and down during the day also. They are providing load following service. So that's -- those are two types of dispatchable generators. They are just -- one of them is automatic, and the other one is -- it can be -- it can be either manual dispatch or computer controlled, versus other generators, like solar, which are just you get what you get. It's just -- it's a generator that just -- that provides whatever it can generate that particular -- that particular moment.

Q. So is it an important issue, whether you have batteries or not, is it just about being able to fully dispatch?

A. That helps it -- move it in the right direction. That provides more value to system operators who need to -- who need to be able to control and manage the system when the system is stressed.

Q. Could you foresee anyone ever being able to avoid the redispatch charge if they couldn't fully dispatch?

A. Could you say that again?

Q. Well, just, you know, could you ever see anyone being able to avoid the redispatch charge without being able to fully -- if they couldn't fully dispatch?

A. Yeah. The redispatch charge -- yeah, this starts getting into a gray area where the redispatch charge is really intended to address the intermittency.

If you add a battery, it starts -- if that's the way the battery is going to be operated, is to take care and make the output smoother, then that seems like it would be -- that would lend itself to being exempt from the redispatch charge. Because that's what the redispatch charge is for. It's to -- it's to have the cost cause or compensate for the increased cost due to the intermittency. If the cost causer can smooth out their -- can smooth their output, then it seems like a good case for exempting from the redispatch charge.

Q. All right. Thank you.

CHAIR MITCHELL: Questions on the Commission's questions?

MR. DANTONIO: No further questions.

CHAIR MITCHELL: Okay, gentlemen, you are excused. Thank you.

MR. SMITH: Madam Chair, I realize the order of the witnesses has, I believe, NCSEA going after SACE and maybe Ecoplexus as well, but Tom Beach, our witness, has a date certain for today, so I was wondering if we could go outside of the order that was filed and allow Mr. Beach to testify next?

CHAIR MITCHELL: Any objections to

Mr. Beach's appearing now?

MR. BREITSCHWERDT: No.

MR. SMITH: Thank you.

(Pause.)

MR. BREITSCHWERDT: Madam Chair -- Chair Mitchell, while we are passing things out, I think we mentioned this yesterday, but just in the interest of expediency, the Duke companies were the only party to have any cross reserved for Mr. Wallace, and we said we don't have any questions for him. So I think he was planning to appear at some point to read his summary into the record. So to the extent that's not necessary, might save us 15 minutes.

CHAIR MITCHELL: Okay. Thank you, Mr. Breitschwerdt.

(Pause.)

CHAIR MITCHELL: Good morning, Mr. Beach. Let's go ahead and get you sworn in.

R. THOMAS BEACH,

having first been duly sworn, was examined

and testified as follows:

MR. SMITH: Madam Chair, at this time, since the other parties are doing it, NCSEA would like to introduce its relevant early filings into the record, this including the initial comments, including four attachments filed in this docket on February 12, 2019, and reply comments filed on March 27, 2019.

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

MR. SMITH: Thank you.

(NCSEA's initial comments, including four attachments filed on February 12, 2019, and reply comments filed on March 27, 2019, were admitted into evidence.)

DIRECT EXAMINATION BY MR. SMITH:

Q. Mr. Beach, please state your name and business address for the record.

A. My name is R. Thomas Beach. My business address is 2560 Ninth Street, Suite 213-A, Berkeley, California 94710.

Q. On whose behalf are you testifying today?

A. I'm testifying on behalf of the North Carolina Sustainable Energy Association.

Q. Thank you. And did you cause to be prefiled on this docket on June 21, 2019, direct testimony consisting of 22 pages and 1 exhibit?

A. Yes, I did.

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

A. I just have one typo on page 6, line 17. The abbreviation for Duke Energy Carolinas was misspelled as DED instead of DEC.

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

A. Yes, they would.

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

CHAIR MITCHELL: Without objection, that motion is allowed.

(Beach Exhibit 1 was identified as marked when prefiled.)

(Whereupon, the prefiled direct testimony of R. Thomas Beach was copied into the record as if given orally from the stand.)

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	)

DIRECT TESTIMONY OF R. THOMAS BEACH ON BEHALF OF NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE, AND EMPLOYER.

A. My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q. PLEASE STATE YOUR EDUCATIONAL AND OCCUPATIONAL EXPERIENCE.

A. My experience and qualifications are described in my *curriculum vitae*, attached here to as **Exhibit 1**. As reflected in my CV, I have more than 35 years of experience in the natural gas and electricity industries. I began my career in 1981 on the staff at the California Public Utilities Commission ("CPUC"), working on the implementation of the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). Since 1989, I have had a private consulting practice on energy issues and have testified on numerous occasions before state regulatory commissions in eighteen states. My CV includes a list of the testimony that I have sponsored in various state regulatory proceedings concerning electric and gas utilities.

Q. PLEASE DESCRIBE MORE SPECIFICALLY YOUR EXPERIENCE ON AVOIDED COST ISSUES, PARTICULARLY AS THEY APPLY TO RENEWABLE AND DISTRIBUTED GENERATION PROJECTS.

A. In addition to working on the initial implementation of PURPA while on the staff at the CPUC, in private practice I have represented the full range of qualifying facility ("QF") technologies – both renewable small power producers as well as gas-fired cogeneration QFs – on avoided cost pricing issues before the utilities commissions in California, Oregon, Nevada, Montana, and North Carolina (in Docket No. E-100, Sub 140). With respect to the renewable generation issues under consideration in this case, I have testified on solar economics in Arizona, California, Colorado, Idaho, Massachusetts, Minnesota, New Hampshire, New Mexico, Oregon, and Virginia. Since 2013, I have co-authored cost-benefit studies of distributed solar generation ("DSG") in Arizona, Arkansas, California, New Hampshire, and North Carolina.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE IN FRONT OF THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes, I have. I testified for NCSEA in 2014 in Docket No. E-100, Sub 140, including preparing direct, response, and rebuttal testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present NCSEA's position on a specific set of issues in this docket, as identified in the Commission's *Order Scheduling Evidentiary Hearing and Establishing Procedural Schedule* (Hearing Order) in this docket, issued April 24, 2019. The direct testimony and exhibits of the North Carolina utilities on these issues was filed on May 21, 2019. Finally, on May 21, 2019 Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP"), and the

North Carolina Utilities Commission – Public Staff ("Public Staff") filed a *Stipulation of Partial Settlement Regarding Solar Integration Services Charge* ("Integration Stipulation"). This testimony will address the following issues in the Hearing Order:

c. Duke's Quantification of Ancillary Services Cost of Integrating QF Solar;

d. Duke's Proposed Solar Integration Charge "Average Cost" Rate Design and Biennial Update;

e. Dominion's Proposed Re-Dispatch Charge; and

f. NCSEA's and Public Staff's Proposals Related to Differing Ancillary Services Costs for Innovative QFs.

All of these issues are related to the costs of integrating higher amounts of solar generation into the systems of the North Carolina utilities. Finally, I will comment on the Integration Stipulation between DEC/DEP and the Public Staff.

Q. HAVE YOU PREVIOUSLY SUBMITTED INFORMATION AND ANALYSIS FOR THE RECORD IN THIS DOCKET?

A. Yes. On February 12, 2019 NCSEA submitted its initial comments in this docket, which included as Attachment 2 an affidavit that I prepared with a report (Report) on certain avoided cost issues under review in this case.

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

A. I have reviewed the North Carolina utilities' filings in this docket proposing their avoided cost rates to become effective in 2019, including the direct testimony and exhibits filed on May 21, 2019. I have also reviewed elements of their workpapers as well as their responses to certain discovery requests propounded by NCSEA and other parties, as documented in my Report and its workpapers. I also used additional documents and studies as listed in my Report and in this testimony, as well as the results of analyses performed by me or by my staff under my direction. That analytic work is discussed in my Report and available in my workpapers.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. This testimony provides the Commission with a broader context in which to evaluate the proposals of the utilities to adopt integration charges that would be subtracted from the avoided cost rates paid to future QFs on their systems. The integration cost study that DEC and DEP submitted, for example, shows increasing integration costs per MWh of solar output, as solar penetration increases. However, the actual experience of system operators in states, such as California, with higher penetrations of solar than North Carolina do not substantiate the results of the DEC/DEP study, which is based on a simulation and not actual experience. This testimony presents data on the actual ancillary service costs experienced by the California Independent System Operator (CAISO), which shows that ancillary service costs have not changed over a period in which the amount of wind and solar resources integrated by the CAISO has increased nine-fold. Similarly, I discuss several traditional vertically-integrated utilities that each have performed a series of wind and solar integration studies as the penetration of these resources on their systems has grown, with successive studies showing declining integration costs per MWh of renewable output.

The broader context of actual experience with solar integration is that system operators and utilities in the U.S. are "learning by doing," and developing ways to integrate large amounts of wind and solar generation without increasing ancillary service costs. These techniques can include improved solar forecasting, better use of real-time data from solar facilities, and greater cooperation with neighboring utilities, including the trading of imbalances within the hour through new market mechanisms such as the Energy Imbalance Market ("EIM") that has been so successful in the western U.S. Further, as the penetration of renewables with zero variable costs increases, the impact is to unload marginal gas-fired resources that become available to provide ancillary services, increasing the supply and reducing the costs for such services.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. My primary recommendation is that the Commission should not adopt the integration charges proposed by DEC, DEP, and Virginia Electric and Power Company d/b/a Dominion Energy North Carolina ("DENC"). Any costs to integrate the growing penetration of solar resources in North Carolina will be offset by other benefits of these new resources that the utilities have not recognized, including lower market prices and avoided transmission and distribution capacity costs, as discussed in more detail in my previously-submitted Report. Instead of implementing an integration charge, the Commission should direct the utilities under its jurisdiction that operate balancing areas in North Carolina to study the benefits of forming an EIM with the nearby PJM Interconnection.

If the Commission does adopt an integration charge, existing and committed QFs should be exempt from the charge, and the charge should be capped at no more than what the Commission determines to be the average integration cost for this tranche of solar studied. This would recognize the experience that actual integration costs per MWh of solar output do not appear to increase with solar penetration, if the system operator takes proactive steps to minimize integration costs. Finally, if an integration charge is adopted, I support the direction of one provision of the stipulation on integration cost issues that the Public Staff and DEC/DEP filed on May 21, 2019 – the provision that would not apply an integration charge to any QF that materially reduces the need for additional ancillary services by using physical energy storage, contractual dispatch capabilities, or other innovative mechanisms. I recommend that the Commission provide more specific details on qualifying for this exemption so that prospective QFs understand the additional investment or operating constraints that will be required to qualify.

II. INTEGRATION ISSUES

Q. ALL OF THE ISSUES CITED ABOVE CONCERN THE INTEGRATION COST ANALYSES SUBMITTED BY DED/DEP AND DNCP. PLEASE EXPLAIN YOUR PERSPECTIVE ON THE INTEGRATION COST ISSUE.

A. My Report did not address the technical details of the utilities' integration cost studies. Instead, I focused on the broader contexts for these studies. North Carolina obviously is not the only state in the U.S. with a rapidly-growing penetration of renewable resources. As a result, there is a growing body of evidence on both the benefits and costs of integrating new renewables, as utilities and system operators have "learned by doing" in integrating growing fleets of wind and solar resources and as there is more evidence on the market impacts of these new resources with zero variable costs. The utilities' integration studies at best only examine one aspect of integrating solar resources – the impact on the utilities' ancillary service costs – and even then, the results are not consistent with the actual experience of utilities elsewhere in the U.S. that also are integrating large amounts of solar resources. In addition, as my Report emphasizes, the Commission also needs to consider the benefits of integrating distributed solar generation that are not included in avoided cost rates. The Astrapé study for DEC/DEP fails to quantify or consider these benefits. These benefits include:

- **Lower market prices.** It is widely acknowledged that the growth of zero-variable-cost renewables, plus lower natural gas prices, has resulted in a broad reduction in electric market prices that has undermined the economics of baseload coal and nuclear resources.[1] Avoided cost rates have declined steadily in North Carolina for the last three years, due in significant part to lower natural gas and electric market prices. The studies cited in my Report indicate that the current penetration of renewables

[1] In https://ei.haas.berkeley.edu/research/papers/WP292.pdf, James Bushnell and Kevin Novan of the University of California at Davis find that renewable investment in California has been responsible for the majority of price declines in the California Independent System Operator's (CAISO) energy market over the last five years. Similarly, Lawrence Berkeley National Laboratory (LBNL) researchers have identified significant impacts on wholesale market prices from increasing penetration of renewables; see, http://eta-publications.lbl.gov/sites/default/files/report_pdf_0.pdf. MIT's Paul Joskow has also written about the impacts of rapid wind and solar penetration on wholesale markets, and the resulting challenges of retaining existing generators through market incentives alone; see https://economics.mit.edu/files/16650.

could easily account for a 4% reduction in energy market prices in the state, which would substantially offset the proposed solar integration charge.[2]

- **Avoided transmission and distribution capacity costs**, as discussed at length in Section III.C of my Report.

These benefits will more than offset any integration costs.

A. Learning by Doing

Q. PLEASE DISCUSS WHY THE UTILITIES' STUDIES ARE INCONSISTENT WITH THE ACTUAL OBSERVED COSTS OF INTEGRATING A HIGH PENETRATION OF SOLAR RESOURCES.

A. The DEC/DEP study from Astrape is based entirely on production cost simulations of each utility's individual control area, adding must-take solar generation to each utility's existing portfolios of on-system resources. The utilities have not introduced evidence of what their actual ancillary service costs are today or of how those costs have been impacted, if at all, by the growing amounts of solar generation on their systems. These simulation studies do not consider ways in which the utilities may adapt their system operations to minimize the cost of integrating solar generation – steps that can include improved solar forecasting, better use of real-time data from solar facilities, and greater cooperation with neighboring utilities (including the greater trading of imbalances within the hour). In fact, nothing that

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[2] A 4% reduction in energy market prices in the range of $30 to $40 per MWh would substantially reduce or eliminate the integration costs proposed by DEC ($1.10 per MWh) and DEP ($2.39 per MWh). Four percent is the level of the market price suppression benefit of solar calculated from studies in the market of the New England Independent System Operator, as discussed on page 19, footnotes 36 and 37, of my Report.

Duke has provided in this proceeding exhibits its own efforts to mitigate intermittency issues on the grid, and, instead, pushes the entirety of the cause and the proposed solution onto future QF developers.

Nor do the utility studies recognize or consider that the changes in the avoided cost rate design that may result from this proceeding – shifting the peak avoided costs into late summer afternoons and winter mornings – will result in an increased use of solar tracking systems and storage. The addition of these technologies will reduce the variability of solar output and allow a significant portion of solar output to be dispatched into the time-of-use periods when power is most valuable to the system. The Commission should not adopt integration cost studies premised on an erroneous assumption that the solar to be built in the future in North Carolina will resemble the solar that has been installed to date.

Q. CAN YOU PROVIDE EVIDENCE OF A STATE WITH A LARGE PENETRATION OF SOLAR RESOURCES THAT HAS NOT EXPERIENCED SIGNIFICANT INTEGRATION COSTS?

A. Yes. Today, California has 20,000 MW of installed solar on the grid of the California Independent System Operator (CAISO) plus 6,700 MW of wind. Of the 20,000 MW of solar on the CAISO system, 12,000 MW are wholesale, utility-scale projects and 8,000 MW are behind-the-meter solar installed by almost one million utility customers.[3] The recent annual peak demands on the CAISO grid have been

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[3] See, http://www.caiso.com/informed/Pages/CleanGrid/default.aspx. The data on behind-the-meter solar is from https://www.californiadgstats.ca.gov/.

in the range of 46,000 to 50,000 MW.[4] Wind and solar now supply about one-quarter (25%) of the electricity on the CAISO system.[5] This is a much higher penetration of wind and solar than exists in North Carolina today or than has been modeled for North Carolina in any of the scenarios examined in this case.[6] The CAISO has integrated this high penetration of wind and solar resources without a discernable increase in its costs for ancillary services, which it obtains from a market for those services. **Figure 1** below shows the history of ancillary service costs on the CAISO system from 2006-2018 (red dashed line), expressed as a percentage of the CAISO energy market costs in each year. The figure also shows the growth of wholesale wind and solar generation in California (green bars); these resources have increased nine-fold (from about 5,000 GWh/year in 2006 to 45,000 GWh per year in 2018).[7] Ancillary service costs for the CAISO have fluctuated between 0.5% to 2.0% of CAISO energy market costs over this period.[8] The primary cause for these fluctuations has been the availability of large hydro resources (blue bars). Ancillary service costs increase in wet years when hydro generation is abundant (such as 2011 and 2017), because hydro resources are

[4] See, http://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf.
[5] This includes about 19% of the wholesale generation and 6% of loads served by on-site solar.
[6] The DEC/DEP Astapé study modeled a maximum of 3,020 MW of solar on DEC and 4,610 MW of solar on DEP, for a total of 7,630 MW on a system with a coincident peak of about 32,000 MW. See DEC/DEP Direct Testimony (Wintermantel), at Figure 2. This is similar to the penetration of wholesale solar on the CAISO system today, but the CAISO also integrates 8,000 MW of grid-connected, behind-the-meter solar.
[7] From the California Energy Commission's website with power source data for California: https://www.energy.ca.gov/almanac/electricity_data/total_system_power.html. Note that this is wholesale generation, and does not include the generation from on-site, behind-the-meter solar, which supplied approximately 15,000 GWh per year of load in 2018.
[8] Data on ancillary service costs as a percentage of CAISO energy market costs is from the CAISO's *Annual Report on Market Issues and Performance* over this period. These reports can be accessed on the CAISO website at http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx.

operated to produce energy rather than to supply ancillary services. In dry years, when hydro production is low, the hydro operators participate more actively in the ancillary services market because that is the best way to maximize the revenue from the limited water stored behind the dams. As a result, in those years ancillary service costs fall, as shown by the low ancillary service costs during the recent drought years of 2014-2015. Thus, as Figure 1 shows, ancillary service costs are strongly correlated with hydro conditions.

However, there has not been a discernable trend toward higher ancillary service costs despite the glaring fact that wind and solar generation *has grown by a factor of nine*. The dotted red line in Figure 1 for 2014-2018 shows the CAISO's ancillary service costs in these years including the CAISO's share of the intra-hour savings in balancing costs from the western Energy Imbalance Market ("EIM"). The EIM savings have reduced significantly the CAISO's costs to operate the California grid, even as the penetration of wind and solar has reached new highs and continues to grow.

Figure 1

Including the EIM savings, the CAISO's ancillary service costs over the last five years have averaged 1.0% of energy market costs; this is below the long-term average (2006-2018) of 1.2% of energy market costs. Thus, there is no evidence that the high penetration of wind and solar resources that the CAISO system has integrated in recent years has increased ancillary service costs. Although the California Public Utilities Commission began a process to develop wind and solar integration charges, it has not seen the need to complete that process and permanently adopt such charges.[9]

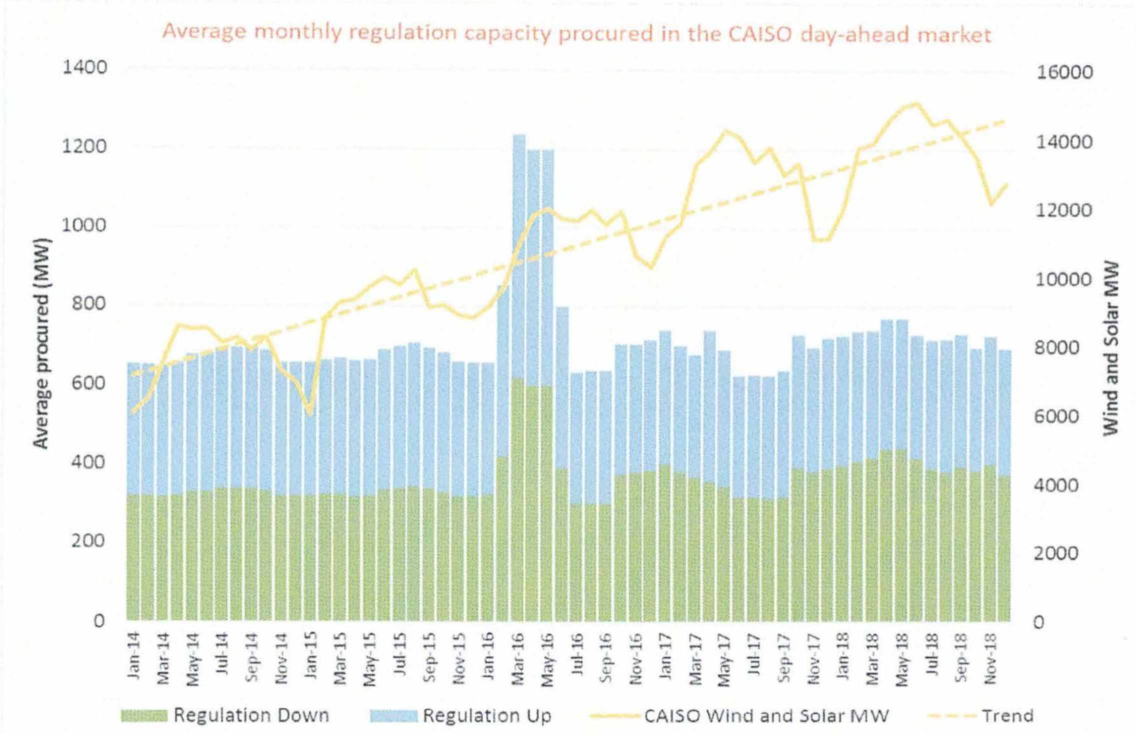
In early 2006, the CAISO increased the amount of regulation that it purchases, from 300-400 MW to 600 MW (in both directions), due to a concern

[9] The California commission has had a series of rulemaking proceedings to administer the state's Renewable Portfolio Standard ("RPS") program. The rulemaking initiated in 2015 (R. 15-02-020) included as an issue the continuing development of integration cost adders (see R. 15-02-020, at p. 6), but this issue was dropped in the next RPS rulemaking initiated in 2018 (R. 18-07-003).

with the increasing amounts of variable wind and solar generation. This increase in regulation accounts for part of the increase in ancillary service costs in 2016 over 2015 shown in Figure 1 (the rest of that increase appears due to wetter hydro conditions). However, after a few months in 2016 the CAISO refined its algorithm for the amount of regulation that it procures, and has been able to return to the use of just 300-400 MW of regulation, even with the steady increase in wind and solar resources over the last five years. This data on the CAISO's procurement of regulation from 2014-2018 is shown in **Figure 2** below.[10] This is another example of the "learning by doing" that is enabling system operators to minimize the integration costs associated with growing penetrations of variable renewables.

[10] The regulation up and down quantities are day-ahead procurement data from the CAISO's monthly market performance reports, at http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx. For example, Table 6 at page 16 or 45 of the CAISO's December 2018 monthly report is at http://www.caiso.com/Documents/MarketPerformanceReportforDecember2018.pdf. The wind and solar output data are monthly maximums of hourly CAISO wind and solar outputs (to show a measure of the amount of wind and solar capacity), from the CAISO's renewables watch output data files, which are available at http://www.caiso.com/market/Pages/ReportsBulletins/RenewablesReporting.aspx.

Figure 2



Q. ARE YOU AWARE OF TRADITIONAL, VERTICALY-INTEGRATED UTILITIES THAT HAVE PERFORMED A SERIES OF WIND OR SOLAR INTEGRATION STUDIES OVER TIME, AS THE PENETRATION OF WIND OR SOLAR RESOURCES ON THEIR SYSTEMS HAS INCREASED?

A. Yes. Both PacifiCorp and Idaho Power have performed several solar or wind integration studies over time, as these utilities have added significant amounts of these renewable resources to their systems.

The following **Tables 1 and 2** summarize these studies, which generally show that integration cost estimates have declined over time, even as more renewables have been added by these traditional utilities.

Table 1: *PacifiCorp Integration Costs ($ per MWh)*[11]

Resource	Date of Study		
	2012	**2014**	**2017**
Wind	$2.55	$3.06	$0.44
Solar	n/a	n/a	$0.60
	Resources (MW)		
Wind	2,126	2,543	2,793
Solar	n/a	n/a	1,000

Table 2: *Idaho Power Integration Costs ($ per MWh)*[12]

Resource	Date of Study	
	2014	**2016**
Solar	0-100 MW: $0.40 0-300 MW: $1.20 0-500 MW: $1.80 0-700 MW: $2.50	0-400 MW: $0.27 0-800 MW: $0.57 0-1,200 MW: $0.69 0-1,600 MW: $0.85
	Resources (MW)	
Solar	0	325

There are a variety of factors that account for the much lower integration costs in the most recent PacifiCorp and Idaho Power studies, including (a) methodological improvements, (b) reduced market prices, and (c) the increased availability of regulation-capable gas-fired resources displaced by new renewables. Significantly, the most recent studies from both PacifiCorp and Idaho Power included review by a technical review committee of outside experts from institutions such as the National Renewable Energy Laboratory ("NREL"), the Western Renewable Energy Generation Information System ("WREGIS"), and the Utility Wind Interest

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[11] The 2012 and 2014 wind integration costs are from PacifiCorp's 2015 Integrated Resource Plan (IRP), at Appendix H, Table H.3. The 2017 wind integration costs are from PacifiCorp's 2017 IRP, Volume II, at Appendix F, pp. 120-123, esp. Tables F.14 and F.16.

[12] For the 2014 results, see Idaho Power, Direct Testimony of Philip B. Devol, Idaho PUC Case No. IPC-E-14-18 (July 1, 2014), at p. 5. For the 2016 solar integration costs, see Idaho Power, *Solar Integration Study Report*, (April 2016), at pp. vi and 21, esp. Tables 2 and 9.

Group ("UWIG").[13] Idaho Power also reached a settlement with stakeholders concerning the design of its most recent integration study.[14] DEC and DEP did not take either step in preparing their integration study for this proceeding. I recommend that the Commission require stakeholder consultation and a technical review group for any future integration studies. Finally, I note that the most recent PacifiCorp and Idaho Power studies do <u>not</u> include consideration of the intra-hour balancing savings that both PacifiCorp and Idaho Power are realizing in the western EIM, which are further reducing their intra-hour costs for the load following resources needed to integrate renewables. As discussed in greater detail below, a market of this type applied in the Carolinas could result in significant benefits for Duke and its ratepayers.

B. No Utility Is An Island

Q. ONE OF YOUR CENTRAL CRTIQUES OF THE DEC/DEP INTEGRATION STUDY IS ITS ASSUMPTION THAT DEC AND DEP ARE INDIVIDUAL BALANCING AREAS NOT CONNECTED TO THE REST OF THE EASTERN INTERCONNECTION. IN RESPONSE, THE DUKE UTILITIES RE-RAN THE STUDY FOR THE COMBINATION OF BOTH DEC AND DEP, IN OTHER WORDS, RECOGNIZING THAT THEY ARE INTERCONNECTED AND HAVE A JOINT OPERATING AGREEMENT. PLEASE COMMENT ON THE RESULTS OF THIS NEW ANALYSIS.

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[13] See the 2017 PacifiCorp and 2016 Idaho Power studies referenced in footnotes 10 and 11.
[14] See the stipulation approved by the Idaho PUC in Order No. 33227 in February 2015 (Case No. IPC-E-14-18).

A. Not surprisingly, integration costs dropped by about 15% when the two utilities were analyzed together.[15] This demonstrates, on a small scale, what the EIM is demonstrating across the entire Western Interconnection – the costs of integrating renewables decline when utilities cooperate to integrate renewables across as wide a footprint as possible. I fully expect that integration costs would decline further if other adjacent utilities were added and if those utilities cooperated to reduce load following costs on a mutually-beneficial basis. It is my understanding that Duke is already in the business of making market purchases and sales with neighboring utilities, so there should be a pathway via those relationships to working with these neighboring utilities to reduce intra-hour balancing costs.

Q. DEC AND DEP DISMISS NCSEA'S COMMENTS ON THE BENEFITS OF AN EIM BECAUSE "NO SUCH MARKET CONSTRUCT EXISTS ACROSS THE ENTIRE EASTERN INTERCONNECTION."[16] PLEASE COMMENT.

A. No such market exists because utilities and system operators have not taken the initiative to create one, and because regulators have yet to encourage them to create the market construct needed to realize these ratepayer savings. The western EIM began with an agreement in 2014 between just the CAISO and PacifiCorp, but since then has spread across almost the entire Western Interconnection and now includes utilities in every state in the WECC except Colorado and Texas. There are several important reasons for the success and rapid spread of the western EIM:

[15] DEC/DEP Reply Comments, at pp. 92-94.
[16] *Ibid.*, at p. 90.

- First and foremost, since its inception, **the EIM has saved money for every participating utility.** These benefits are not "anecdotal," as DEC/DEP assert;[17] they are tracked and documented by the EIM participants in quarterly reports.[18] The cumulative benefits to EIM participants have reached $650 million as of the end of the first quarter of 2019.[19]
- The EIM is an overlay on, and does not change, traditional hourly scheduling processes. Each balancing area continues to be run by the existing operator.
- The EIM can be used by balancing areas and system operators that operate under a variety of market and regulatory structures. Western EIM participants include investor-owned utilities, publicly-owned utilities, and an independent system operator that are located across ten states and a Canadian province.
- The EIM is simply a balancing mechanism that seeks out beneficial trades of resources within the hour to reduce balancing and load following costs for participants and to decrease renewable curtailments. This is "found money" for all participants, who now have a means to seek out and resolve inefficiencies in the intra-hour dispatch of their resources.

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[17] *Ibid.*
[18] See, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.
[19] See, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

I note the recent announcement that the Southwest Power Pool (SPP) is planning to form an EIM on its footprint.[20] The western EIM in the WECC plus this new EIM in SPP would provide access to an EIM for utilities in the entire western half of the U.S. Clearly, there are system operators in the East, such as the PJM Interconnection, that have the experience and technical expertise to run an EIM. The Duke utilities would be logical partners to start an EIM with PJM given the growth of solar resources in North Carolina (and of both wind and solar elsewhere in the East) and the clear need to maximize the efficiency of intra-hour dispatch to address renewable variability. I expect that there will be interest in joining such an EIM from other utilities in the South, such as Georgia Power, that have seen significant solar development in their service territories. It is my recommendation that, in lieu of implementing an integration charge on solar QFs, this Commission should direct the utilities under its jurisdiction that run balancing areas in North Carolina to study the benefits of forming an EIM with the nearby PJM system.

[20] See, https://www.spp.org/newsroom/press-releases/spp-proposes-western-energy-imbalance-service-market-to-bring-cost-savings-and-grid-modernization-to-the-west/.

C. Stipulation on Integration Costs

Q. PLEASE ADDRESS THE STIPULATION ON INTEGRATION COST ISSUES THAT THE PUBLIC STAFF AND DEC/DEP FILED ON MAY 21, 2019.

A. The principal issues with this stipulation are (1) it fails to address the benefits of renewables that offset any integration costs and (2) it accepts the flawed DEC/DEP integration cost study that assumes the Duke utilities are islands and is based on inaccurate solar modeling (as discussed in the report "Modeling the Impact of Solar Energy on the System Load and Operations of Duke Energy Carolinas and Duke Energy Progress" attached to NCSEA's initial comments). Beyond those concerns, the stipulation is positive in exempting existing and committed QFs (i.e. those that committed to sell before November 1, 2018 or that bid into the CPRE Tranche 1 RFP) and in capping the integration charge so that prospective QFs have certainty in the integration costs that they will face during the term of their contract. However, it is inappropriate to cap the integration charge at the level of the calculated incremental cost for integrating the last 100 MW of solar additions, instead of at the level of the average integration charge for the whole tranche of solar studied. These caps of $3.22 per MWh for DEC and $6.70 per MWh for DEP are far too high and well above, to my knowledge, the solar integration charges adopted elsewhere in the U.S. As I have discussed above, the experience elsewhere has been that integration costs fall over time, as utilities gain experience operating their systems with higher penetrations of renewables and implement new forecasting, operating, and market processes to minimize those costs. Further, the growth of renewables will displace energy from flexible, gas-fired resources, which will increase the supply (and thus lower the cost) of resources available to provide the load following capacity and ancillary services needed to integrate renewables. As a result, the integration charge, if one is adopted, should be capped at no more than the average integration cost for this tranche of solar studied, that is, at $1.10 per MWh for DEC and $2.39 per MWh for DEP based on the Astrapé study (or at whatever lower average integration cost the Commission adopts after review of the critiques of that study).

Q. IS THE STIPULATION CONSISTENT WITH NCSEA'S PROPOSAL WITH RESPECT TO "DIFFERING ANCILLARY SERVICES COSTS FOR INNOVATIVE QFS"?

A. The stipulation proposes that the integration charge should apply prospectively to new solar QFs "unless those solar generators can demonstrate that the facility is capable of operating, and shall contractually agree to operate, in a manner that materially reduces or eliminates the need for additional ancillary services requirements (as reasonably determined by the Companies) through inclusion of energy storage devices, dispatchable contracts, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generators ("controllable solar generators")."

This provision is headed in the right direction, in my opinion, but lacks needed specificity so that prospective QFs understand more precisely the requirements necessary to avoid the integration charge. For example, my Report recommended that solar projects that include significant storage (a four-hour discharge capacity equal to at least 50% of the AC solar nameplate) should not be assessed integration costs. The Commission also should recognize that the new peak periods and structure for avoided cost rates are likely to result in less variability and more control in solar output even without explicit requirements, as generators add storage and dispatchability in response to the new pricing periods.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MR. SMITH:

Q. Mr. Beach, did you prepare a summary of your testimony?

A. Yes, I did.

Q. Can you please read that now?

A. Sure. Commissioners, thank you for the opportunity to testify before you today. Again, my name is Tom Beach, and I'm the principal consultant at Crossborder Energy, and I'm appearing here on behalf of NCSEA.

The Commission has set for this hearing several issues concerning the proposals of the utilities to adopt integration charges that would be subtracted from the avoided cost rates paid to the future QFs on their systems. What I endeavor to do in my testimony is to provide the Commission with a broader context in which to evaluate these integration charge proposals, the methodologies used to calculate them, and the results they produce. For example, the integration cost study that the two Duke utilities submitted shows increasing integration costs per megawatt hour of solar output as solar penetration increases. However, the actual experience of the system operator in California, a state with a higher penetration of solar than North Carolina, does not substantiate the Duke study's results that integration costs will increase as solar penetration grows. Please note that the Duke study is based on a simulation, that is a modeling exercise, and not on actual experience. My testimony presents data on the actual ancillary service costs experienced by the California Independent System Operator which shows that ancillary service costs have not changed as a percentage of overall market costs over a 13-year period in which the amount of wind and solar resources integrated by the CAISO has increased nine-fold. Similarly, I discuss several traditional vertically integrated utilities, PacifiCorp and Idaho Power, that each have performed a series of wind and solar integration studies as the penetration of these resources on their systems has grown with the successive studies showing declining integration costs per megawatt hour of renewable output.

The broader context of actual experience with solar integration is that system operators and utilities in the U.S. are learning by doing, and developing ways to integrate large amounts of solar and wind generation without increasing ancillary service costs. These techniques can include improved solar forecasting, better use of realtime data from solar facilities, and perhaps most important, greater cooperation with neighboring utilities, including trading of imbalances within the hour through new market mechanisms such as the Energy Imbalance Market that has been so successful in the Western U.S. One of the key flaws of the Duke study is that it models each Duke utility as an island without neighboring utilities, thus discounting the potential reduction in integration costs through greater regional cooperation with neighboring utilities. Finally, as the penetration of renewables increases, their impact is to unload marginal natural gas-fired resources. The unloaded capacity of these gas-fired resources will become available to provide ancillary services, increasing the supply and reducing the cost for such services.

To summarize the California experience, today California has 20 gigawatts of installed solar plus almost 7 gigawatts of wind on the grid of the CAISO. Of the 20 gigawatts of solar on the CAISO system, 12 gigawatts are wholesale, utility-scale projects, and 8 gigawatts are behind-the-meter solar installed by almost 1 million utility customers. Wind and solar now supply about one quarter of the electricity on the CAISO system. This is a much higher penetration of wind and solar than exists in North Carolina today or that has been modeled for North Carolina in any of the scenarios examined in this case. Over the last five years, with the highest amounts of solar, the CAISO's ancillary service costs have averaged about 1 percent of their wholesale market costs. This is actually slightly less than the long-term average of these ancillary costs since 2006, which is 1.2 percent of wholesale market costs. Thus, California has been able to integrate this rapidly growing level of solar output without any visible increase in ancillary service costs to balance the system.

One key to this performance have been the growing cooperation between utilities in the West in meeting intra-hour balancing needs more efficiently through the energy imbalance market created in 2014. The Western EIM has saved money for every one of its participating utilities with a savings totaling $650 million as of the end of the first quarter of 2019 and has produced significant reductions in renewable curtailment. This is found money for all participants. The EIM began in 2014 with just two participants, the

CAISO and PacifiCorp, but has grown to cover almost the entire WECC footprint. There is no reason, in my opinion, why the Duke utilities could not recreate this success by forming an EIM with the neighoring PJM connection. Commissioners, it's important to remember that the EIM is simply an overlay on existing scheduling practices. Each utility continues to operate their own balancing area, and an EIM can accommodate utilities that operate under a variety of market and regulatory structures. It's my recommendation that, instead of implementing an integration charge on solar QFs, this Commission should direct the utilities under its jurisdiction that run balancing areas in North Carolina to study the benefits of forming an EIM with the nearby PJM system.

If, despite this recommendation, the Commission decides to adopt an integration charge, it should be capped at the level of the average integration charge for the whole tranche of solar studied, not at the level of the charge for the last 100 megawatts of the tranche, as proposed in the stipulation between the Duke utilities and the Public Staff. Their higher cap is inappropriate, given the evidence that I present that actual integration costs do not need to increase as solar penetration grows.

Finally, my testimony supports, in concept, the Duke Public Staff stipulation that innovative QFs that agree to operate in a manner that materially reduces or eliminates the need for additional ancillary services should not have to pay the integration charge. This provision is headed in the right direction but lacks the specificity -- but lacks needed specificity so that prospective QFs understand more precisely the requirements required to avoid the integration charge. For example, solar projects that include significant storage, by which I mean a four-hour discharge capacity equal to at least 50 percent of the solar nameplate, should not be assessed integration costs.

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

MR. SMITH: NCSEA Witness Tom Beach is now available for cross examination.

MS. FENTRESS: Thank you. Good morning, Mr. Beach. My name is Kendrick Fentress. I'm an attorney with Duke Energy. How are you?

MR. DODGE: Excuse me. I'm sorry, Ms. Fentress. I didn't know, based on the order, I think we had a few minutes for cross examination.

MS. FENTRESS: Oh, I apologize.

MR. DODGE: Just a couple of quick questions. I apologize.

CROSS EXAMINATION BY MR. DODGE:

Q. Thank you. Sorry about that. Good morning, Mr. Beach. How are you today?

A. I'm well, thank you.

Q. Good to see you again. Just -- I only had a couple of questions, fairly quick ones.

On page 15 of your testimony, your direct testimony -- actually, the discussion starts on page 14, if you could flip to that page.

A. Okay.

Q. And you're describing two integration studies done by PacifiCorp and Idaho Power, both traditional vertically integrated utilities, that you indicate that those costs have showed going down over time based on updates or revisions to those studies.

Do you know if either of those studies -- in either of those studies, utilities were modeled as an island, or were they allowed to rely on neighboring assistance for intra-hour volatility?

A. You know, I do believe that those studies -- I think they did largely model them as islands. I think that I know a little bit more about the Idaho Power study than about the PacifiCorp studies, but I believe that is true. I do know that these studies did not -- neither of them took into account the benefits that both PacifiCorp and Idaho Power had realized from the energy imbalance market in the West. They -- these studies had been done without including that experience.

Q. Thank you. And then turning to the last page of your direct testimony, this is the example you provided, and actually it's in your summary as well today, about a project that includes significant storage could be exempted from the solar integration service charge. So you specifically state a four-hour discharge capacity equal to at least 50 percent of the AC solar nameplate should not be assessed those integration costs.

Could you describe why you picked those parameters for a facility to avoid the charge?

A. Sure. Four-hour storage for 50 percent of the nameplate capacity roughly can store about a third of the output of the solar project. That's -- I wanted to choose a sizing for the storage so that it would be able to store a significant amount of the output of the project. So that will result in, potentially, significant, you know, reshaping of the output -- both the input and the -- well, the significant reshaping of the output profile of the project. And, for example, that power can be discharged at a relatively constant rate during the peak hours, as opposed to the normal, you know, fluctuations of solar output. And so that reshaping and control over the output of a significant amount of the generation from the project is definitely going to reduce the variability of the output.

Q. Okay. Great. And you, kind of, hit the nail on the head where I was going with that.

So there would be some expectation that the output from that would be reshaped or controlled in some way, so would that be -- would the utility have input on those control guidelines, how that system would operate?

A. Potentially, it could. That, you know, would be a matter to be worked out between the QF and the utility. But, certainly, under the new pricing structure that has been proposed in this case, where you have some well-defined peak periods, either on winter mornings or summer afternoons, if you have a solar-plus-storage project, there is a very strong economic incentive for that storage to be discharged during those peak periods, obviously, because that's when the prices are higher. And -- but -- so one would expect that the output of the project during those peak periods will be significant and probably, at first order of proximation, would be a steady amount of power, but I would expect that the QF and the utility could work together to -- if, for example, introduce dispatchability that could make the power even more valuable.

Q. Thank you. No further questions.

CHAIR MITCHELL: Ms. Fentress?

CROSS EXAMINATION BY MS. FENTRESS:

Q. Hello again, Mr. Beach. I wanted to start with your testimony today. I think you say, on page 9 of your testimony, that California is a state with large solar penetration that has not experienced significant integration costs; is that true?

A. Yes. I think that is true. The California Commission started down a process very similar to the one that you-all are going through here a few years ago. But I think that as -- especially as the results of the energy imbalance market has become clear, the importance of integration costs has dropped on the

Commission's, you know, list of priorities.
Q. And I think you have also mentioned, in support of your statement about California integrating a large amount of solar, on page 11 of your testimony, that ancillary service costs are strongly correlated with hydro conditions; is that correct?
A. Yes. That's right. And it's a bit counterintuitive because they actually -- ancillary service costs go down in dry years and increase in wet years. You might think that it would be the opposite, that when you had more hydro, the ancillary service cost would be lower, but that's actually not the case. It's the opposite.
Q. I'm correct, am I not, that your testimony does not address hydro conditions in North Carolina?
A. No.
MS. FENTRESS: And I'd like to pass out an exhibit, or I would like to have Mr. Breitschwerdt pass out an exhibit, and approach the witness, Madam Chair, and may I have this marked Beach Cross Examination Exhibit Number 1?
CHAIR MITCHELL: The exhibit will be marked as Beach Cross Examination Exhibit Number 1.
(Whereupon, Beach Cross Examination

Exhibit Number 1 was marked for identification.)

MS. FENTRESS: I'll wait for Mr. Breitschwerdt to finish passing out, because Mr. Breitschwerdt has my copy.

Q. Mr. Beach, if you could take a look at what's been placed in front of you, would you agree that this is an irradiance map by NREL showing the United States?

A. I will accept that, yes.

Q. And NREL stands for the National Renewable Laboratory; is that correct?

A. Yes.

Q. And if you look at this map, you will see the western part of the United States, which is, I think most of it, or parts of it, would be in the EIM you mentioned; is that correct?

A. I mean, almost all of it is, yes.

Q. And then it shows also North Carolina.

Is it fair to say that the irradiance -- the color showing the irradiance in the western part of the country where California is is a red and a dark red?

A. Yes.

Q. And the irradiance in North Carolina is yellow, maybe a little orange; is that correct?

A. Yes.

Q. And so would the differences in irradiance levels have any impact on the intra-hour volatility of solar output?

A. You know, I have never studied that, so it's possible, but I would need to -- I would need to see some data. I mean, just the fact that it's sunnier in the U.S. Southwest, I mean, that's -- that's not surprising. But whether that translates into increased volatility, I would need to see a lot more data in order to agree with that statement. You know, this is a pretty large-scale picture, and, you know, just looking at California, it looks entirely red in this picture, but California has lots of microclimates. For example, along the coast, in the summer, we have fog that comes in and out during the day; and in the Sierra Nevada in California there are, you know, clouds that develop in the afternoons, very similarly to what happens in the East. So I think that this is a pretty broad-brush picture, and I would not want to draw any conclusions about solar variability from this picture.

Q. Well, could I ask you -- I will put the word irradiance into lawyer terms -- does irradiance mean how brightly and steadily the sun shines?

A. It doesn't -- it certainly has something to do with how brightly it shines. I would disagree that it says how steadily it shines.

Q. Would you agree this map shows there is a greater irradiance in the western part of the country and less in North Carolina?

MR. SMITH: I'm going to object. Mr. Beach is not an expert in irradiance, as far as I can tell. None of his testimony deals with irradiance. This map isn't dated. It isn't outlined in any meaningful date range. It could be any given day, any given week. So there is no context for him to testify on it, on top of the fact that, again, he's not an expert on irradiance.

MS. FENTRESS: If you look at the map, it does say kilowatt hours, it does have a metric -- I'm sorry, my vision is not very good -- square mile and day. And also, I do believe that irradiance -- he did say that irradiance could have an impact on solar output volatility, and therefore, I think it's fair to cross him if he is speaking about California, holding it up as an example of integration cost. I think it is fair to explore the differences, as shown by the National

Renewable Laboratory, in California sunshine and North Carolina sunshine.

MR. SMITH: And again, I will just restate that, while the kilowatt per day, it doesn't indicate what day, what month, what year. And, on top of that, he's already indicated that he isn't an expert on irradiance, he's an expert on the solar market in California and across the country.

CHAIR MITCHELL: Understanding the limitations of the exhibit and understanding Mr. Beach's credentials as well, I will allow Ms. Fentress to continue.

MS. FENTRESS: Thank you.

Q. With that, Mr. Beach, is it fair to say that this map shows a difference between California and North Carolina with respect to solar irradiance?

A. What it shows is, if you put a solar panel in California versus one in North Carolina, over the course of a year, the one in California will produce more electricity, but whether that electricity will be more volatile, like I said, would require analyzing a lot more data.

Q. Thank you. So you did not analyze that data

as part of your recommendation?
A. No.
Q. All right. Turning to the energy imbalance market, Mr. Beach, as I understand it, the energy imbalance market is administered by Cal ISO; is that correct?
A. Well, Cal ISO is the ones whose computers run the market. I believe they do have a stakeholder committee that administers the market that is not -- has participants from all of the utilities, or has participants from the utilities that are involved that cover 10 states and a Canadian province, so I'm not sure what you mean by administer. It is the ISO's computers that run the market, but I believe the stakeholder group that administers it is much more broadly constituted.
Q. Thank you. And would you agree that participation in the EIM is at the BA level; is that correct, for these utilities?
A. I think the participants in the market each run their own balancing area, and the EIM does not change that.
Q. Certainly. And if DEC or DEP were to join in an EIM, would you agree that North Carolina approval

would be needed?

A. Yes. I believe it's in -- I think all of the utilities that have joined the EIM have gotten authorization from their state regulatory commissions to do so.

Q. And do you understand that DEC and DEP's BAs also include South Carolina?

A. I think I do -- I think that is correct. And there are utilities in the Western EIM, like PacifiCorp operates in six states, so -- and they were one of the original two participants in it. So that's -- would be certainly possible for an Eastern EIM.

Q. So -- but you understand the service territory for DEC and DEP also runs into South Carolina, correct?

A. Yes.

Q. So South Carolina approval would also be needed? The South Carolina Utilities Commission would also have to approve entrance into an EIM?

A. Sure. Just like PacifiCorp presumably got approval from six states in order to participate.

Q. In fact, on page 19 -- just to follow up on that -- of your testimony -- and if you would like to turn there -- you mention other Southeastern states that may be interested in joining an EIM, which I believe you said was -- I'm sorry, other Southeastern states that would join EIM, they too would need Commission approval, as I think you just indicated?

A. Yes.

Q. And I think -- is it true that they would also need FERC's approval; that any utility that wanted to join would need FERC's approval?

A. Yes.

Q. And to obtain FERC's approval, the utility would have to submit a market power analysis to join EIM?

A. You know, I actually don't know if they had to do that or not.

Q. Would you accept, subject to check?

A. That they did?

Q. Yes.

A. Sure.

Q. Okay. Thank you. I think that might be just more expeditious.

So you would agree that there are a number of regulatory approvals that DEC and DEP would have to go through in order to join an EIM; is that correct?

A. Sure. For regulated utilities, there almost always are.

Q. In contrast, if I could turn to your testimony with respect to -- I believe it's on page 20 -- of the pending stipulation between Duke Energy and the ratepayer advocate, in this case, the Public Staff.

Understand that you have concerns with that, and that you have put that in your testimony, but I also -- on page 20, line 11, is it fair to say that, beyond those concerns, your testimony indicates that the stipulation is positive in exempting existing and committed QFs from the charge?

A. Yes.

Q. And you also indicate that -- I understand you have a differences in how the cap should be administered, but the capping of the integration charge is also a positive?

A. Yes.

Q. Thank you. I have nothing further.

CHAIR MITCHELL: Dominion?

MR. DANTONIO: No cross from Dominion.

MR. SMITH: I just have a couple of redirect.

CHAIR MITCHELL: Redirect? Okay.

MR. SNOWDEN: I'm sorry. Cube Yadkin would like to ask just a couple of follow-up questions in response to Ms. Fentress' cross examination.

CHAIR MITCHELL: Mr. Snowden, I will allow it, but we have -- we have established an order of cross examination that is set forth in the filing that Duke made, and so this would be out of order. So just for purposes of going forward, let's try to stick to the order we established in this filing.

MR. SNOWDEN: I'm happy to wait until after the other parties have done their -- I thought we moved on to redirect.

CHAIR MITCHELL: We are through all of the cross examination at this point, and we had moved to redirect, but I will allow your questions for now, as long as you move through them efficiently, and then --

MR. SNOWDEN: They will be very short.

CROSS EXAMINATION BY MR. SNOWDEN:

Q. Mr. Beach, thank you. I'm Ben Snowden with Kilpatrick Townsend for Cube Yadkin Generation.

A. All right.

Q. Mr. Beach, you testified, in response to Ms. Fentress' questions, that ancillary services costs in CAISO are higher in wet years when hydrogeneration is abundant?

A. Yes.

Q. Okay. And that is because hydro operators participate more actively in ancillary service markets in dry years; is that right?

A. Yeah. It's because, in a dry year, there is less water to run through the dams. So it's actually -- you want to use the water in a dry year to provide the most value possible. So you, basically, save it and use it for things like ancillary services where you, you know, would get paid more. Whereas in a wet year, such as we're experiencing this year, you've got a lot of water behind the dam that you've got to run through the dam. Or things like the Oroville Dam fiasco that we had a few years ago where the spillway eroded. So you have to run your hydro generation at max output in more hours in a wet year.

Q. Okay. Thank you. And so it's the active participation of hydrogeneration in ancillary services markets that drives ancillary services' costs down; would you say that?

A. Well, yeah. Like I said, it can, and I think the picture that's in my testimony kind of shows that ancillary service costs do fluctuate from year to year, and that fluctuation is highly correlated with hydro conditions.

Q. So would you say that this phenomenon is, in part, result of there being a functioning ancillary services market in California?

A. Well, it's certainly more visible as a result of there being a functioning market so you could actually look at what the prices are.

Q. So it's not that abundant hydrogeneration necessarily results in a greater need for ancillary services, so much as the fact that they can be operated at certain conditions to provide greater ancillary services?

A. Yeah. In other words, in a dry year, the supply -- the number of generators who are capable and willing to provide ancillary services goes up.

Q. Okay. Thank you, no further questions.

CHAIR MITCHELL: Redirect, please.

MR. SMITH: Yes. Just a couple quick questions on the Beach Cross Exhibit Number 1.

REDIRECT EXAMINATION BY MR. SMITH:

Q. Understanding that I have -- first of all, this has been established, essentially, in my objection, but I wanted to get it on the record, understanding also that I have taken the position that you are not an irradiance expert, but assuming any sort of information that you know about irradiance, is it fair to say that irradiance maps can vary over time, and depending on the time of year?

A. Yes. And, you know, this is -- it looks like the units here are kilowatt hours per square meter per day, but you are right, it does not say over what period of time.

Q. So just to hammer that down, there is no date range indicated on this exhibit?

A. Not that I see.

Q. And there is no -- this appears to be pulled from a website, correct?

A. Yes.

Q. And there is no date as to when this was pulled from the website?

A. No.

Q. There is no indication when this was pulled, I should say?

A. No.

Q. Thank you. No further.

CHAIR MITCHELL: Questions from the Commission?

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Beach, as I was following you, it seems to me that you have indicated that California is further along in this process than we are here in this territory, and that the prices or the costs of the integration costs have come down over time as you learn.

Then why wouldn't it be fair to have a charge at this stage that's continually re-evaluated and that lowers as we go, if that turns out to be our experience?

A. (No response.)

Q. I guess I'm asking you, do you still think it's unfair, at this stage, to impose a charge?

A. Well, I think that it's important to -- I mean, first of all, although California does have more solar than North Carolina, you're nipping at our heels so to speak, and I think it is important to look at, you know, what the experience has been in California, because it appears that North Carolina is heading in that direction. And, you know, like I said, I think that this was a significant concern of the Commission about five years ago or so, but it's turned out that the CAISO has been able to manage the growth in solar without incurring -- I wouldn't say the costs have gone down, but they have stayed the same, even though solar has been growing rapidly.

So, as I stated in my statement, at a minimum, you should not assume that solar integration costs are going to go up over time, and if they are capped, they should be capped at the average level, not at the level of the last amount of solar that you put in that is indicated in the study.

Q. So whatever those initial costs were when they first began when they were learning -- so it was some higher level of cost than is there today -- because they didn't implement the charge, those costs were paid by the ratepayers by doing the cost --

A. For example, there is a figure on -- Figure 2 on page 14 of my testimony that shows the amount of monthly regulation capacity that the CAISO procured in its market, and you could see, in 2016, there is a little spike in those amount of regulation. At that point, the CAISO did think that it needed more regulation to integrate renewables, so it increased the amount of regulation that it procured for about a six-month period in 2016. But it found that it actually could operate the system with a much lower level of regulation, similar to what it had done before 2016. And so yes, there were some increased costs temporarily in 2016 for those -- that increased regulation. But the key point here is that they learned, and they were able to bring down the amount of regulation that they needed. And since then, it's returned to pretty much what it was before then.

Q. Okay. Thank you.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Beach, you have your testimony there in front of you?

A. Sure.

Q. And I'm going to refer to Figures 1 and 2. Figure 2 appears to be sourced back to CAISO; is that right?

A. Yes. It's from their annual report.

Q. It is?

A. Yes.

Q. And there is no indication on the prior page, page 12 by Figure 1, as to the source of that; is that also from their performance reports?

A. Yes, it is. I apologize if I didn't have a cite in there, but it is from their -- they do an annual report on their market operations.

Q. That's the source of Figure 1?

A. Yes.

Q. The annual report?

A. Yes.

Q. Okay. Do you know if, in the annual report, there was any attempt to, sort of, disaggregate and take a look at large hydro separately from wind and solar and do the same graphic that's shown on Figure 1 on a disaggregated basis?

A. You mean --

Q. Did they make any attempt to apportion or attribute the ancillary service costs to hydro separately from wind and solar?

A. No. They run a market for ancillary service for the whole system.

Q. That's what I thought, and I just didn't know if they made any effort to disaggregate the data and make an attribution.

A. No. And the one thing I will -- on Figure 1, the one thing that comes from other sources is -- in the last five years, that dotted line showing their ancillary service cost with the EIM savings.

Q. EIM savings?

A. Yeah.

Q. And what's the source for that?

A. The energy -- the CAISO report's savings for each utility in the EIM on a quarterly basis, so I used those savings for the CAISO to produce that lower dotted line in Figure 1.

Q. Thank you.

EXAMINATION BY CHAIR MITCHELL:

Q. Mr. Beach, you have provided some testimony on a recommendation related to avoiding the integration charge. Can you talk for a minute about -- I believe you heard my question a minute ago to Mr. Petrie about shifting versus smoothing and how we, as the Commission, should, you know, start to think about the values that energy storage provides to the system. Your example in your testimony and your testimony in response to questions from Mr. Dodge suggest that a shifting and a smoothing might occur under certain circumstances or configurations of solar plus storage that would provide value.

Can you talk for a minute about, sort of, those two phenomenon, which provides more value to the system, or if some combination of them should be sought to provide value to the system?

A. Sure. I think that storage provides value on both of those dimensions. In terms of -- and I think that you-all are certainly headed down the road of providing very strong economic signals for solar plus storage to be operated to shift the output of those facilities into the times of day when the power is the most valuable. If you adopt rates that have much higher rates during the peak periods, you know, you will get solar projects to add storage or to be built with storage from the beginning, and those projects will output -- will store their power and then output it during the hours when it's most valuable. And that -- so that's a way to address the duck curve, if you will. The fact that you need to ramp up generation on summer evenings and perhaps in winter mornings when you have -- you know, your demand is peaking. So that will address the duck curve issue, the shifting issue.

Then, you know, one of the things about storage is that it also can be, you know, programmed to output power. It could be -- my understanding is it could be programmed both to store and to output power. Doesn't have to do it in a constant amount per hour.

It can vary how much is being stored at any -- or discharged at any moment in time based on what the needs of the system are. So that can help your moment-to-moment variability issue as well. So storage has a great potential in both of those dimensions.

Q. And just one last question.

In your experience and your observation, how much control does the utility need over the energy storage system to ensure that maximum value is provided to the system? I mean, is that a critical feature of -- or critical part of ensuring that battery storage does actually provide system benefits?

A. Yes. It's -- that is -- I think that that is -- those kind of details are things that are still being, you know, definitely an evolving area and where those elements are still being worked out. I think the shifting piece of it is easier, because you just need to establish peak periods when, you know -- you need to change your peak periods so that, as you are doing in this proceeding, to reflect the new realities on the system. California has done that.

For example, they now have a statewide peak period of 4 p.m. to 9 p.m. It used to be more like noon to 6:00 before all the solar came on. But now, given the solar penetration, the peak period has changed to 4 p.m. to 9 p.m. So that is encouraging solar-plus-storage projects to shift their output into that 4 p.m. to 9 p.m. peak period when -- you know, after the sun has -- when the sun is setting, and when, you know, the duck curve issues are most prominent. I think the variability issue is something that is being worked on, in terms of what kind of relationship between the generator and the utility is most valuable. That's an area that I think is still emerging exactly how that's gonna work out.

Q. And is that because technology continues to evolve? I mean, can you explain why that is an emerging issue or sort of --

A. Yeah. It's an -- it is, because, you know, people are -- there are not a lot of solar-plus-storage projects yet. A lot of them -- there is quite a few in the pipeline, and storage can have -- you know, there has been quite a bit of storage developed in the East, for example, to provide regulation services. You know, very quick response storage. So storage could do that, but it needs to have -- you know, there need to be the right economic signals and the right relationship between the person who operates the storage and the utility or the system operator to provide those benefits. And, you know, because storage can provide multiple services, you have to -- you know, the storage has to be full in the right -- at the right times, and it has to get the right signals in order to provide multiple services, but it is capable of doing that.

Q. Thank you.

CHAIR MITCHELL: Questions on Commission's questions?

Oh, Commissioner Brown-Bland.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Beach, I want to follow up on what Chair Mitchell was asking, and if you think you have enough knowledge and experience in this area, then I would like your opinion, but which -- so, based on what you know from the experiences out West, and if you can, you know, extrapolate that to North Carolina, which one -- what is a more valuable use of storage for us, the use to deal with the duck curve, the shifting or the smoothing? Or, do you see them -- and she asked you, was it similar. And I'm speaking more valuable for the system, not more valuable for the QF.

A. My guess is that the shifting is more valuable. Just looking at the difference between the on-peak rate and the off-peak rate, that's a pretty big difference. And assuming that represents the value to the system, that value is gonna be bigger than offsetting $1 or $2 per megawatt hour integration charge. So I think the shifting value is more valuable, but, you know, the smoothing will be important too.

Q. Okay. Thank you.

CHAIR MITCHELL: Questions on Commission's questions?

Mr. Dodge?

MR. DODGE: Thank you.

RECROSS EXAMINATION BY MR. DODGE:

Q. Mr. Beach, I just have two quick questions. First, following up on Commissioner Brown-Bland's questions about -- actually this may have been Commissioner Clodfelter's. I apologize. Figure 2 -- you were referring to Figure 2, and you referred to the spike back in 2016 where the higher amount of capacity was procured but then lowered back to normal levels. You have a trend line showing on that chart that shows -- I believe that trend line is indicating a trend in increasing amounts of wind and solar in the Cal ISO system; is that correct?

A. Yes.

Q. And then you don't have a trend line for the amount of regulation capacity procured. It is relatively level, but it is -- does it slight increase over that period of time?

A. It does slightly increase, yeah, but it's pretty minor.

Q. And you were speaking with Chair Mitchell about energy storage as well, and Cal ISO -- is storage participating in the regulation and capacity market at this time?

A. Yes, but the amounts are quite small, on the order of 100 to 200 megawatts.

MR. DODGE: Thank you.

MS. FENTRESS: No, thank you.

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

Okay, Mr. Beach, thank you very much.

THE WITNESS: Thank you.

MS. BOWEN. Madam Chair, the Southern Alliance for Clean Energy will now call Mr. Kirby to the stand.

CHAIR MITCHELL: Good morning, Mr. Kirby. Let's go ahead and get you sworn in.

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

MS. BOWEN: Thank you, Madam Chair.

DIRECT EXAMINATION BY MS. BOWEN:

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

A. Brendan Kirby. My business address is now 12011 Southwest Pineapple Court, Palm City, Florida.

Q. And did you cause to be prefiled direct testimony in this proceeding?

A. I did.

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

A. I do.

Q. Thank you. Proceed.

A. I failed to mention, on page 8, line 18 of my direct testimony, that I sponsored an additional Exhibit D, Duke Energy's presentation to the June 4th to 5th, 2019, meeting of the North American Electric for Reliability Corporation's Operating Committee titled "Integration and Monitoring of Distributed Energy Resources and System Operations."

Q. Thank you. 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. Yes.

Q. And was exhibit -- were the exhibits to your testimony prepared by you or at your direction?

A. Yes.

MS. BOWEN: Madam Chair, I would move to have Mr. Kirby's prefiled direct testimony entered into the record as if given orally from the stand, and have the exhibits attached to his testimony identified as Premarked Kirby Exhibits A, B, C, and D entered into the record at this time.

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

(Kirby Exhibits A through D were admitted into evidence.)

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

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	)	**DIRECT TESTIMONY OF BRENDAN KIRBY, P.E. ON BEHALF OF SOUTHERN ALLIANCE FOR CLEAN ENERGY**
	)	
	)	

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Brendan J. Kirby P.E. I am an electric power systems consultant, and my business address is 12011 SW Pineapple Court, Palm City, Florida.

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

A. I am testifying on behalf of the Southern Alliance for Clean Energy.

Q. Please summarize your qualifications and work experience.

A. I am currently a private consultant with numerous clients including the Hawaii Public Utilities Commission, National Renewable Energy Laboratory (NREL), over fifteen utilities, the Energy Systems Integration Group (ESIG), Electric Power Research Institute (EPRI), the American Wind Energy Association (AWEA), Oak Ridge National Laboratory (ORNL), and others. I retired from the Oak Ridge National Laboratory's Power Systems Research Program.

I have 44 years of electric utility experience, and I have been working on electric power industry restructuring and ancillary services since 1994 and spot retail power markets since 1985.

I am a licensed Professional Engineer with a M.S degree in Electrical Engineering (Power Option) from Carnegie-Mellon University and a B.S. in Electrical Engineering from Lehigh University.

A copy of my curriculum vitae is included as Kirby Exhibit A.

Q. Can you please describe in greater detail your experience related to power system operations?

A. Yes. I will note at the outset that Duke Energy's Reply Comments filed previously in this proceeding mischaracterized my power systems qualifications and incorrectly referenced another affiant's qualifications in an effort to discount my extensive power systems experience.[1] To correct any misunderstanding, I have attached a full resume, including a list of relevant publications, to this testimony, and further provide a brief summary of my relevant experience here.

After graduating from Lehigh University with a Bachelor of Science in Electrical Engineering in 1975 I started my career at the Long Island Lighting Company. I moved to the Department of Energy's (DOE) Oak Ridge Reservation in 1977 after receiving a Master's Degree in Electrical Engineering (Power Option) from Carnegie Mellon University. My first fifteen years in Oak Ridge were spent with the operating contractor for DOE's 7,000 MW uranium enrichment complex performing operational and planning load flow, transient stability, short circuit and specialty analysis both individually and in joint studies with the Tennessee Valley Authority, Union Electric, Central Illinois Public Service, Illinois Power, and Kentucky Utilities. In 1985 I participated in taking the 3,040 MW Paducah Gaseous Diffusion Plant from a firm power contract

[1] *See* Duke Reply Comments at p. 87 ("Mr. Kirby—who has no power system operational experience…"). This statement references n. 248, which cites SACE Response to Duke Energy Request No. 1, Item 1-24, Docket No. E-100 Sub 158. This Data Response was prepared by Mr. Wilson in response to Duke's inquiry regarding his qualifications and therefore describes Mr. Wilson's qualifications, not my qualifications.

supply paradigm to real-time supply from the wholesale, inter-utility, spot energy market.

I spent my second fifteen years in Oak Ridge as a senior power systems researcher in the Power Systems Research Program at the Oak Ridge National Laboratory (ORNL) where I conducted research into:

- Electric power system reliability and security,
- Ancillary services – especially including the definition of, need for, measurement of, and supply of regulation and load following,
- Electric industry restructuring,
- Wind and solar generation integration,
- Distributed resources,
- Demand side response, and
- Energy storage.

Dr. Erik Hirst and I published our first ORNL report on ancillary services (including regulation) in March 1995, one year before the Federal Energy Regulatory Commission (FERC) issued its landmark Order 888 on electric industry restructuring and unbundling of ancillary services.[2] FERC discussed and referenced our ancillary services report and comments in Order 888 as "Oak Ridge".

Over the following ten years we published over fifteen ORNL reports and dozens of technical papers further refining ancillary services (including regulation) definitions, requirements, quantification metrics, and allocation

[2] B. Kirby, E. Hirst, and J. VanCoevering 1995, *Identification and Definition of Unbundled Electric Generation and Transmission Services*, ORNL/CON-415, Oak Ridge National Laboratory, Oak Ridge, TN, March.

methods. I extended this work to include the provision of spinning reserve and regulation through demand response. I worked with ALCOA to have their Warrick Indiana aluminum smelter load provide regulation to the Midwest Independent System Operator.

Working with colleagues at the National Renewable Energy Laboratory we extended this work to the ancillary services requirements of and provision by wind and solar resources.

Immediately following the August 14, 2003 northeast blackout, I was sent by FERC to conduct the system operator field interviews of PJM, American Electric Power, and the Michigan Electric Coordinated System that became part of the North American Electric Reliability Corporation (NERC) US/Canada Investigation Team Report. I was subsequently detailed to FERC from ORNL for a year to provide technical support as FERC increased their internal capabilities in preparation for the establishment of mandatory reliability standards.

During that year, among other tasks, I was the FERC representative on the initial NERC Reliability Readiness Audits of Control Areas and Reliability Coordinators covering about half of North America (including Duke, TVA, and Southern).

I started private consulting while still at the Oak Ridge National Laboratory but have been consulting full time since my retirement from ORNL in 2007. Clients have included over 15 utilities (including TVA, Southern, and NextEra) as well as (among others):

- The Hawaii Public Utilities Commission (where, among other things, I was appointed the Special Advisor for Demand Response),
- National Renewables Energy Laboratory (NREL),
- Edison Electric Institute (EEI),
- Electric Power Research Institute (EPRI),
- Voith Hydro,
- Wartsila,
- Caterpillar,
- The World Bank,
- Regulatory Assistance Project (RAP),
- American Wind Energy Association (AWEA),
- Canadian Wind Energy Association, and
- Energy Systems Integration Group (ESIG).

My research interests continue to include wind and solar power integration, ancillary services, demand side response, distributed resources, electric industry restructuring, bulk system reliability, energy storage, and advanced analysis techniques. I have published, at ORNL and after, over 180 papers, articles, and reports. I coauthored a pro bono amicus brief cited by the United States Supreme Court in its January 2016 ruling confirming FERC demand response authority. I have a patent for responsive loads providing real-power regulation and am the author of a NERC certified course on Introduction to Bulk Power Systems: Physics / Economics / Regulatory Policy. I served on the NERC Standards Committee and the NERC Integration of Variable Generation Task Force (IVGTF).

Q. Have you previously filed testimony as an expert witness in a regulatory proceeding?

A. Yes. I have testified in proceedings regarding wind and solar integration, bulk power system reliability, ancillary services, and demand response before Commissions in Georgia, California, Minnesota, Texas, Wyoming, and Hawaii, as well as before the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate and respond to the Duke Energy Carolina ("DEC") and Duke Energy Progress ("DEP") (together "Duke Energy" or "the Companies") proposed solar integration charge and the *Stipulation of Partial Settlement Regarding Solar Integration Services Charge*, entered into by Duke Energy and Public Staff on May 21, 2019 ("Solar Integration Charge Stipulation"). My testimony responds to direct testimony, comments, and the stipulation filed by Duke Energy in this proceeding.

Q. Are you sponsoring any Exhibits?

A. Yes. I am sponsoring two expert reports: *Duke Energy Proposed Integration Charge*, included as Kirby Exhibit B, and *Proposed Solar Integration Re-Dispatch Charge*, included as Kirby Exhibit C. I am also sponsoring my curriculum vitae, which is included as Kirby Exhibit A.

Q. Please provide an overview of your testimony.

A. My testimony explains that Duke Energy's proposed solar integration charge is based on an analysis methodology that does not represent the physical balancing requirements or requirements imposed by NERC mandatory reliability standards.

The proposed solar integration charge was developed for Duke Energy by Astrapé Consulting and documented in a November 11, 2018 study titled "Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study" (*Ancillary Service Study* or the *Study*). The unreasonable assumptions and flawed methodology used in the Study will result in increasingly unrealistic estimates of required regulation reserves as solar penetration increases. The Commission should not approve a solar integration charge that is based on regulation requirements that Duke will not actually experience or costs that Duke will not actually incur.

My testimony will discuss several major errors in the *Ancillary Service Study's* assumptions, each of which results in the Study overestimating the Companies' regulatory requirements and artificially inflating solar integration cost projections:

(1) The $LOLE_{FLEX}$ reliability metric is unrelated to mandatory NERC reliability requirements and is inappropriate for this analysis.

(2) The production cost modeling assumption that DEP and DEC are islanded systems, disconnected from the Eastern Interconnection, is wrong.

(3) Linear scaling of expected short-term variability from new solar generators as solar penetration rises is physically incorrect.

All of these assumptions result in overstating the regulation requirements and related costs that DEP and DEC will experience as solar penetration increases.

My testimony will also explain my past concerns with the quality of data used in the *Study*, and will discuss my concerns regarding the terms of the Solar Integration Charge Stipulation entered into by Duke Energy and Public Staff, including the use of marginal rather than average costs when calculating the proposed integration services charge cap.

Finally, I discuss concerns with Dominion Energy's proposed Intermittent Generation Re-Dispatch Charge.

II. DUKE ENERGY RELIES ON THE *ANCILLARY SERVICE STUDY'S* FLAWED METHODOLOGY TO JUSTIFY EXPONENTIALLY INCREASING SOLAR INTEGRATION CHARGES

Q. Please explain the basic methodology underlying the *Ancillary Study Report*. Is this methodology sound?

A. The basic underlying analysis methodology of determining the cost of solar integration by comparing production cost modeling results with and without solar, while holding reliability constant, is well established and has been executed successfully by others. However, the analysis described in the *Ancillary Service Study* is fatally flawed because Astrapé:

(1) invented and applied a wholly inappropriate $LOLE_{FLEX}$ reliability metric;

(2) modeled DEC and DEP as isolated power systems rather than modeling them as they actually operate, as part of the Eastern Interconnection; and

(3) linearly scaled the short-term variability of new solar generation from existing data rather than being modeled to reflect actual aggregation benefits.

Q. What is the effect of this flawed approach at progressively higher solar penetration levels?

A. At high solar penetration levels, the *Ancillary Service Study* generated exponentially increasing integration costs based on the flawed underlying assumptions.[3] This conclusion, which suggests that integration charges must exponentially rise as solar penetration increases in order to cover accelerating integration costs, is inaccurate. This conclusion arises from the use of inappropriate reliability metrics, <u>not</u> due to exponentially increasing physical balancing requirements. If relied upon, this flawed methodology could be used to impose exponentially increasing integration charges upon solar developers when

[3] Testimony and Exhibits of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Direct Testimony of Nick Wintermantel at p. 20 ("Looking to the high penetration scenarios, the Study results indicated an exponentially increasing cost of integrating incremental solar with the conventional fleet.") (hereinafter "Wintermantel Direct Testimony").

they are not justified.

A. Inappropriate Use of the LOLE$_{FLEX}$ Metric

Q. Is LOLE$_{FLEX}$ an appropriate metric for quantifying a solar integration charge?

A. No, the LOLE$_{FLEX}$ metric is not appropriate for quantifying a solar integration charge. Mr. Wintermantel states in his Direct Testimony that "[t]his LOLE metric is traditionally used for IRP purposes to determine target reserve margin and required installed capacity amounts."[4] He further states that:

> The "1 day in 10 year" planning standard is used to ensure a utility has enough capacity installed and available so that only one firm load shed event is forecasted to occur every 10 years. All simulations in the Study were targeted to this level of reliability by adjusting capacity as needed to be consistent with the "1 day in 10 year" planning standard . . .[5]

However, a metric based on a one-day-in-ten-year *planning* adequacy criteria is completely inappropriate for daily operations. Duke Energy's Reply Comments state: "LOLE$_{FLEX}$ essentially requires the system to maintain enough ramping capability to match 5-minute load ramps ***in all but one period every 10 years***"[6] This is not a rational daily operating requirement because it imposes a substantially more stringent requirement than what is actually needed to safely

[4] *Id.* at p. 15

[5] *Id.* at p. 16.

[6] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Reply Comments at p. 96 (hereinafter "Duke Energy Reply Comments") (emphasis added).

and reliably conduct daily operations. This requirement is unnecessary for a Balancing Area operating within the Eastern Interconnection and is not required by NERC mandatory reliability standards.

Q. If a one-day-in-ten years reliability criteria is appropriate for setting IRP generation capacity requirements why is it not an appropriate short-term balancing requirement?

A. The *Ancillary Service Study* explains that "plans must be in place to have adequate capacity such that firm load is expected to be shed one or fewer times in a 10-year period."[7] This is a reasonable long-term generation planning criteria since a shortfall in generation capacity can indeed result in the need to shed firm load in order to avoid a blackout. However, it is a completely inappropriate short-term balancing criteria under non-contingency conditions because a 5-minute imbalance will not result in the need to shed firm load or a blackout. That is why NERC does not require continuous perfect balancing from each BA.

Q. Does Duke admit that their proposed $\text{LOLE}_{\text{FLEX}}$ standard is subjective?

A. Yes. The Reply Comments state: "the standard of 0.1 $\text{LOLE}_{\text{FLEX}}$ is admittedly subjective".[8]

[7] Duke Energy Reply Comments, DEP/DEC Exhibit 2, *Ancillary Service Study* at p. 10 (hereinafter "*Ancillary Service Study*").
[8] Duke Energy Reply Comments at p. 97.

Q. How did Mr. Wintermantel's Direct Testimony address the *Ancillary Service Study's* use of the LOLE$_{FLEX}$ metric?

A. Mr. Wintermantel acknowledges that the LOLE$_{FLEX}$ standard is not a generally used industry metric. He further admits that operational reliability is governed by NERC Balancing standards, which do not include the LOLE$_{FLEX}$ metric employed in the *Ancillary Service Study*.

Q. Is LOLE$_{FLEX}$ of 0.1 a generally utilized industry metric or standard for assessing reliability events caused by lack of flexibility?

A. No. Operational reliability is governed by the NERC Balancing Standards and is measured by different metrics.[9]

Q. Has NERC established mandatory balancing requirements that address short-term variability of loads and uncontrolled generators?

A. Yes. Power system balancing requirements to maintain reliability are established by NERC. These requirements are laid out in mandatory NERC reliability standard BAL-001-2 – Real Power Balancing Control Performance. BAL-001-2 establishes two reliability metrics that apply during normal (non-contingency) operations: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE Limit (BAAL). I discussed CPS1 and BAAL balancing requirements in my expert report. Duke Energy's Reply Comments never disputed the fact that the

[9] Wintermantel Direct Testimony at p. 17.

actual balancing requirements are based on the NERC BAAL and CPS1 metrics and not on the invented $\text{LOLE}_{\text{FLEX}}$ metric.

Q. Can you briefly state the difference between balancing requirements based on the Companies' self-imposed $\text{LOLE}_{\text{FLEX}}$ *Study* metric versus those based on the actual NERC CPS1 and BAAL requirements?

A. Yes. As Duke Energy's Reply Comments state: "$\text{LOLE}_{\text{FLEX}}$ essentially requires the system to maintain enough ramping capability to match 5-minute load ramps in all but one period every 10 years."[10]

Rather than requiring perfect balancing for all but one 5-minute interval in ten years NERC's CPS1 limits the *annual average* imbalances. Further, not all imbalances are bad. When interconnection frequency is below 60 Hz overgeneration helps raise frequency and helps reliability. Similarly, when interconnection frequency is above 60 Hz under generation helps lower frequency and also helps reliability. CPS1 gives credit for those imbalances that help restore interconnection frequency. While an annual average CPS1 score of 100% is required CPS1 scores range from 0% to 200%, so 100% is not perfect balancing. The Balancing Authority ACE Limit (BAAL) does not require perfect balancing either. BAAL only limits ACE deviations that exceed *30 consecutive minutes*. Further, like CPS1, BAAL only limits ACE deviations that hurt interconnection frequency. That is, over-generation is not limited when interconnection frequency

[10] Duke Energy Reply Comments at p. 96.

is below 60 Hz and under-generation is not limited when interconnection frequency is above 60 Hz. ACE limits are lax when frequency is close to 60 Hz and get progressively tighter as frequency deviates farther from 60 Hz.

Therefore, neither of the applicable reliability metrics that DEC and DEP must follow require the Companies to balance load as stringently as the self-imposed $\mathrm{LOLE}_{\mathrm{FLEX}}$ metric. In sum, the *Ancillary Service Study* inflates the balancing requirements far beyond what is actually necessary, and then passes on the cost of achieving this unnecessarily stringent and unrealistic standard onto QFs in the form of an inflated solar integration charge.

Q. Did the *Ancillary Service Study* mention NERC balancing requirements?

A. Yes. The *Ancillary Service Study* references two NERC reliability metrics: CPS1 and CPS2 saying: "Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and CPS2 standards is a critical component of a solar ancillary service cost impact study."[11]

CPS2 is no longer applicable, however. It was replaced in July 2016—well before the *Ancillary Service Study* was published—with the BAAL requirement, discussed above, when BAL-001-02 became the effective standard. CPS2 did not require perfect balancing either. CPS2 required the monthly average 10-minute imbalances to remain below 92 MW for DEC and below 17 MW for DEP *90% of the time*. That is, CPS2 allowed deviations for over 5,000

[11] *Ancillary Service Study* at p. 10.

10-minute intervals each year while $LOLE_{FLEX}$ considers more than 1 5-minute deviation in 10 years unacceptable. Therefore, even the outdated metric the *Ancillary Service Study* does mention does not require nearly as stringent of balancing requirement as $LOLE_{FLEX}$.

Q. Page 35 of Mr. Snider's May 21, 2019 Direct Testimony includes a Figure 5, meant to illustrate an increase in volatility with solar generation currently operating on the DEP power system relative to a no-solar scenario. Please respond to this figure.

A. I would like to make two important points regarding this figure. First, as discussed above, NERC mandatory reliability standards do not require instantaneous balancing of all deviations, so finding a single 2-minute interval with a 65 MW increase in deviation does not equate to a NERC requirement of an additional 65 MW of reserves.[12] Second, Figure 5 shows the results for March 10, 2019, the most variable day of the 10-day sample provided. The other nine days have single point excursions that range from 7 MW to 62 MW (averaging 35 MW) higher with solar than without.

In any case, Figure 5 does <u>not</u> demonstrate that the average deviation is 35 MW greater with solar than without. To the contrary, it shows that the single worst daily 2-minute deviation in this sample of ten days is, on average, a mere 35 MW greater with solar than without. And again, NERC does not require

[12] The *Ancillary Service Study* states that DEP will require 166 MW of additional reserves for the DEP Existing Plus Transition case. *Id.* at p. 49.

balancing each 2-minute deviation. Therefore, Figure 5 seems to prove that the *Ancillary Service Study* significantly overstates the added reserve requirements that increased solar penetration imposes on the Companies' balancing areas.

Q. Has Duke recently discussed efforts to integrate distributed energy resources to account for and mitigate increases in generation variability?

A. Yes, indeed Duke Energy recently represented to the NERC Operating Committee that it has successfully reduced impacts of solar generation short-term volatility.[13] Duke Energy's Adam Guinn made a presentation at the June 4-5, 2019 NERC Operating Committee meeting titled "Integration and Monitoring of Distributed Energy Resources in System Operations". In that presentation Mr. Guinn stated that DEP "tuned" its automatic generation system (AGC) in September 2018 in response to the changing generation resource mix, which is primarily driven by the increase in solar generation. AGC is the central generation control system that sends control signals to each Duke Energy generator every few seconds directing their provision of regulation. More specifically, Mr. Guinn stated that "Control bounds were *__relaxed__* to improve response performance".[14] Mr. Guinn listed a number of benefits that resulted from this relaxing of the AGC regulation control:

- Generators better respond to sustained system needs
- Dispatchable generators no longer chasing fleeting events
- Reduces impacts from Variable Energy Resource 1-min volatility

[13] Duke Energy Progress presentation to the NERC Operating Committee, June 4-5 2019, "Integration and Monitoring of Distributed Energy Resources in System Operations." Kirby Exhibit D.
[14] Duke Energy Progress presentation to the NERC Operating Committee, June 4-5 2019, "Integration and Monitoring of Distributed Energy Resources in System Operations", slide 9. Kirby Exhibit D.

- Improves fleet efficiency
- An ~20% reduction in BAAL exceedance minutes
- Negligible impacts to CPS1%[15]

The presentation to the Operating Committee shows Duke Energy's appropriate operational focus on the actual NERC balancing metrics BAAL and CPS1 rather than the fictitious $\text{LOLE}_{\text{FLEX}}$ metric. It also shows that DEP has reduced the impact of solar generation short-term volatility by no longer "chasing fleeting events." In other words, this presentation demonstrates that the assumptions used in the *Ancillary Service Study* deviate from Duke Energy's actual operations and that the *Study* fails to account for recent improvements in Duke's response performance. No doubt performance will continue to improve as greater experience with integrating solar generation is gained.[16]

Q. How did Duke Energy respond to your findings in its Reply Comments?

A. Duke Energy altogether failed to explain its reliance on the self-imposed $\text{LOLE}_{\text{FLEX}}$ requirement instead of NERC mandatory reliability standards. Instead, it questioned whether my recommendation to consider mandatory industry-wide balancing standards, instead of a fictitious, self-imposed standard, was "intended to be constructive and to improve the precision of the modeling or, in actuality, is a 'poison pill' designed to make the task unachievable."[17] My recommendation

[15] *Id.*
[16] M. Milligan, B. Kirby, T. Acker, M. Ahlstrom, B. Frew, M. Goggin, W. Lasher, M. Marquis, and D. Osborn, 2015, "Review and Status of Wind Integration and Transmission in the United States: Key Issues and Lessons Learned", NREL/TP-5D00-61911, March
[17] Duke Energy Reply Comments at p. 97.

that the Companies model their balancing requirements based on actual, up-to-date NERC standards is not a "poison pill"—it is a reasonable response to a modeling framework that is completely divorced from reality. My concern is compounded by the fact that the Companies appear unwilling to acknowledge that the *Ancillary Service Study's* sole reference to NERC requirements was to a standard that was already obsolete at the time the *Study* was published. While my recommendation that Astrapé adjust its modeling framework to more closely reflect actual balancing requirements may complicate the analysis somewhat, it is not, as Duke Energy suggested, "unachievable." Furthermore, my report suggests the methodology used in a 2016 Idaho Power study as a feasible way of modeling actual balancing requirement. I discuss this study in more detail later in my testimony.

B. Inappropriate Treatment of DEC and DEP as Islanded Power Systems

Q. Are DEP and DEC islanded power systems?

A. No. Treating DEC and DEP as islanded power systems in the *Ancillary Service Study* differs from how Duke actually plans and operates DEC and DEP as interconnected utilities.

Q. Is Duke's proposed solar integration charge based on the assumption that DEP and DEC are disconnected from the Eastern Interconnection?

A. Yes. The *Ancillary Service Study* states that "The utilities are modeled as islands for the Ancillary Service Study."[18]

Q. Why is it important that DEP and DEC be modeled as part of the Eastern Interconnection rather than as islanded power system?

A. Importantly, and fundamentally, NERC reliability requirements are based on operations within an interconnection; specifically, within the 720,000 MW Eastern Interconnection in Duke Energy's case. This is fundamentally important because with interconnected utility operations, small imbalances within one BA do not result in loss of load events under normal conditions. In fact, imbalances are occurring all the time under normal conditions. As Mr. Guinn noted in Duke Energy's presentation to the NERC Operating Committee, there is no need for dispatchable generators to chase "fleeting events."[19] As I discussed above, the NERC standards limit the magnitude and frequency of allowed imbalances, but they do not attempt to eliminate them or restrict them to one-event-in-ten-years.

Utilities interconnect precisely because interconnecting gives all participants tremendous reliability and economic benefits. Only under the most extreme circumstances would DEC or DEP temporarily withdraw from the Eastern Interconnection because doing so would reduce reliability and increase costs dramatically for rate payers with no offsetting benefits. Modeling DEC and DEP as islanded power systems makes no sense for the same reasons.

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[18] *Ancillary Service Study* at p. 13.
[19] Duke Energy Progress presentation to the NERC Operating Committee, June 4-5 2019, "Integration and Monitoring of Distributed Energy Resources in System Operations", slide 9. Kirby Exhibit D.

Q. Has Duke explained why they base the proposed solar integration charge on an analysis that wrongly assumes that DEP and DEC are islanded power systems?

A. The stated reason for modeling DEC and DEP as islanded power systems in the *Ancillary Service Study* is that "it is aggressive to assume that neighbors will build flexible systems to assist DEC and DEP in their flexibility requirements."[20] Mr. Wintermantel elaborates in his Direct Testimony:

> "DEC and DEP systems were modeled as islands for this Study in order to capture the incremental impact of adding solar generation to each system. Each Company is responsible for meeting NERC requirements within its own BA. I have been advised by the Companies' system operators that while the Joint Dispatch Agreement between DEC and DEP does allow 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.
>
> "Although DEC and DEP are interconnected with surrounding regions, additional ancillary services are necessary to integrate solar generation, and these services have a cost. Further, it is inappropriate for the Companies to assume that they are able to rely upon surrounding neighbors for this type of service. While the Companies could hypothetically contract for real-time regulation service from designated generating units in other BAs, this alternative would require securing firm transmission service as well as capacity and energy contracts from the neighboring generating facility owners—both of which would come at a cost. For these reasons, it is appropriate that the Study models the Companies as islands."[21]

These arguments completely misunderstand the benefits of interconnected utility

[20] *Ancillary Service Study* at p. 13.
[21] Wintermantel Direct Testimony at p. 27.

operations and the impacts on regulation requirements and reserves. Utilities started to interconnect over ninety years ago in order to increase reliability while reducing each utility's reserve requirements. This works because of the strong aggregation diversity benefits for load and generation short-term variability under both normal and contingency conditions. Interconnected power systems are more resilient, reliable, and economic than islanded power systems. All utilities participating in an interconnection benefit from reduced reserve requirements. The mandatory NERC reliability standards are based on interconnected operations. Determining reserve requirements for islanded versions of DEC and DEP is irrelevant to the way the power systems, including DEC and DEP, are actually designed, built, and operated.

Put simply, regulation requirements for utilities operating as an interconnection are lower than the regulation requirements for those same utilities operating as islands. This is not a question of obtaining regulating reserves from a neighbor over a firm transmission path. This is a reflection of the reduced requirement for regulation. The *Ancillary Service Study* fails to account for this reduced requirement and therefore overstates the regulation requirements the Companies are actually subject to.

Q. How did Duke Energy Respond to your concerns regarding the modeling DEC and DEP as islanded power systems?

A. Instead of meaningfully responding to the concerns raised in SACE's initial comments, Duke Energy repeatedly mischaracterizes the islanding concern and attempts to obfuscate the valid points raised by myself, the Public Staff, and NCSEA.

For example, in its Reply Comments Duke Energy repeatedly describes other parties' concerns with modeling DEC and DEP as islanded systems as "assuming that the Companies can rely on 'external market assistance'… to provide the load-following reserves required to reliably respond to the intra-hour intermittency and volatility of solar resources."[22] I did not suggest that the Companies obtain "external market assistance" from other utilities. My concern, which Duke Energy never addressed in its comments, is that modeling DEC and DEP as islands completely misses the benefits of interconnected operations—the reduced requirement for moment-to-moment balancing—which are reflected in the mandatory NERC reliability requirements. This is true even if DEC and DEP have no contractual transactions with each other or with any neighbor. In sum, modeling DEC and DEP as islands ignores the fact that the NERC reliability standards the utilities are subject to factor-in the benefits of interconnected operations. Pretending that this is not the case allows the Companies to once again inflate their balancing requirements to an unrealistic level, and pass on the costs necessary to meet these self-imposed requirements onto solar QFs.

[22] Duke Energy Reply Comments at pp. 86, 88 ("Mr. Kirby's presumption that the Companies can rely upon other members of the VACAR RSG to provide regulating reserves to meet intra-hour volatility is simply wrong."); *Id.* at p. 91 ("The parties criticizing the BA island assumption appear to believe that after solar is added to the system, the DEC and DEP BAs should be able to increase their reliance on intra-hour market assistance to alleviate reliability issues caused by solar QFs.")

Q. Are you suggesting that Duke Energy shirk its balancing responsibilities and "lean" on its neighbors by not treating DEC and DEP as islands?

A. No. Just as DEC and DEP are not shirking their contingency reserve obligations or leaning on their neighbors when they participate in the VACAR reserve sharing group neither are they leaning on their neighbors when they follow the NERC BAL-001 standard. By joining the VACAR reserve sharing group DEC, DEP, and every other VACAR member is able to significantly reduce the amount of contingency reserves they carry and still maintain reliability. This is a fundamental benefit of reserve sharing groups, that the total amount of reserves required to maintain the same level of reliability is greatly reduced because the multiple members are treated as a connected whole. If DEC and DEP were treated as islanded systems they would each have to carry enough contingency reserves to cover the loss of their own largest generator. Because they are not islands and are members of a reserve sharing group they can meet NERC standards and operate reliably with only a fraction of the contingency reserves required for islanded operations.

While obtaining contingency reserve aggregation benefits requires DEC and DEP to join the VACAR reserve sharing group they obtain regulation reserve reduction benefits by interconnecting with the Eastern Interconnection. Interconnected utility operation inherently provides regulation benefits to all of the interconnection participants.[23] DEC, DEP, and every other utility simply do not incur the same balancing requirements or costs as part of the Eastern Interconnection that they would incur if they were islands. The NERC reliability standards do not require perfect balancing to maintain reliability and everyone benefits. Aggregation reduces individual balancing requirements. No one is "leaning" on their neighbors or shirking their responsibilities. This is a major reason that utilities started interconnecting over ninety years ago.

The Commission should not allow Duke Energy to try to recover regulation reserve costs based on calculations of what would be required for islanded operations since DEC and DEP do not operate that way.

C. Unsupported Assumption that Solar Variability Scales Linearly

Q. Duke Energy linearly scaled existing solar plant minute-to-minute output data to represent new solar plants. Is that appropriate?

A. No. Of necessity, the *Ancillary Service Study* (and any planning study) modeled solar sites that do not yet exist and for which there is no actual data. Consequently, appropriate solar plant output data must be synthesized for the analysis. It is important that the synthesized data captures aspects of the actual solar plants that will be built. It is also important that the synthesized data represents data that is synchronized to the load data it is paired with to accurately represent net power system variability and uncertainty.

[23] Regulation Sharing Groups are recognized in the NERC standards, but they provide different and additional benefits to those being discussed here.

Linear scaling is reasonable for determining the average energy production from additional solar generation; double the number of solar plants and get about double the energy. It is inappropriate for estimating the minute to minute variability, however. Short-term variations of loads and variable renewable generators are typically uncorrelated among themselves and with each other. Consequently, regulation requirements are not arithmetically additive but instead increase with the root mean square: doubling the solar output increases short-term variability by a factor of about 1.4 (the square root of $[1^2+1^2]$), not 2 (1+1).

Solar plant short-term variability tends to be uncorrelated because solar plants cannot be physically placed on top of each other. They have significant geographic size. They also are typically not all placed side-by-side, giving them even greater geographic diversity. A cloud passing by will not shadow all plants at exactly the same time. Solar short-term variability tends to be uncorrelated for physical reasons.

Longer term trends for both load and solar generation (the daily load pattern, sun cycle, and the passage of weather fronts) result in coordinated load and generation patterns that impact many loads or generators similarly. The aggregate daily load pattern for two municipalities, for example, tend to be similar and the load patterns tend to add linearly. Conversely, short-term minute-to-minute variability for loads, solar plants, and wind turbines tend to be uncoordinated and short-term variability tends to add statistically rather than linearly.

Q. Can you provide an example of another instance where diversity benefits reduce regulation requirements and linear scaling would be inappropriate?

A. Yes, one might consider common household appliances like water heaters (and air conditioners and many other pieces of equipment), which individually have very high variability but collectively present a much smoother profile to the utility. Water heaters and air conditioners do not provide temperature control, for example, by smoothly dialing their output up and down like a light dimmer. Instead they cycle fully on and completely off every few minutes to hold water (or air) temperature within a desired narrow range. This cycling fully on and fully off presents as highly variable individual load to the utility.

If tank type electric water heaters were a brand-new technology a cautious utility might install one to gain experience. They would discover that the water heater cycled its 2.5 kW heating element and then fear that if a million customers installed water heaters the utility could be faced with a 2,500 MW load instantly coming on and off every few minutes. After all, "it is difficult to predict the volatility of future portfolios"[24].

Fortunately, we have a lot of operating history with electric water heaters and we know that they do not synchronize their short-term variability. We know that it is completely inappropriate to linearly scale water heater short term variability. We know that it is completely appropriate to recognize that the longer-term water heater energy use pattern is largely synchronized, with greater

[24] *Ancillary Service Study* at p. 30.

consumption in the morning and evening, but that short-term variability is not. Consequently a utility would not be allowed to charge residential customers for an additional 2,500 MW of regulation reserves that were not actually required "just in case."

Like water heater variability (and air conditioner variability, etc.), solar variability scales statistically, not linearly. With both water heaters and solar generators, the short-term variability of one individual entity is not synchronized with the variability of other individual entities: short-term variability is uncorrelated. Just as with water heaters, it is not appropriate to linearly scale the short-term variability of a few solar generators to represent the aggregate short-term variability of a larger fleet.

Q. Does the scientific literature recognize significantly reduced regulation requirements resulting from geographic diversity of solar plants?

A. Yes. A 2010 Lawrence Berkeley National Laboratory report provides a good example.[25] The report acknowledged that "[e]arly studies of PV grid impacts suggested that short-term variability could be a potential limiting factor in deploying PV."[26] However, after studying variability across multiple solar sites, the report concluded that "accounting for the potential for geographic diversity can significantly reduce the magnitude of extreme changes in aggregated PV

[25] Andrew Mills and Ryan Miser, 2010, Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power, Ernest Orlando Lawrence Berkeley National Laboratory, (Sept. 2010), https://emp.lbl.gov/publications/implications-wide-area-geographic.
[26] *Id.* at p. 2.

output, the resources required to accommodate that variability, and the potential costs of managing variability."[27] The report found that short-term variability of geographically dispersed solar plants is largely uncorrelated and that previous studies that linearly scaled reserve requirements were in error stating: "[a]s is well known for wind, however, accounting for the potential for geographic diversity can significantly reduce the magnitude of extreme deltas, the resources required to accommodate variability, and the potential increase in balancing reserve costs."[28]

Q. Is there evidence in the data supplied by Duke Energy that short-term solar variability does not scale linearly?

A. Yes. An examination of the historic solar output data for DEP and DEC shows this decline in relative variability.[29] For example, for the month of July 2018 DEP had a maximum solar output of 1,630 MW while DEC had a maximum solar output of 427 MW. The maximum coincident solar output for the combination of DEP and DEC was 2,041 MW, just 0.8% below the sum of the DEP plus DEC maximum solar outputs. As expected, maximum solar output is closely correlated for DEP and DEC. Aggregating DEP and DEC does not greatly reduce the maximum solar output of the aggregation. By contrast, the relative short-term intra-hour variability of the aggregation of DEP and DEC is significantly lower than the sum of the variability of the two BAs. The hourly average standard

[27] *Id.*
[28] *Id.* at p. 34.
[29] SACE Data Request No. 2 Item No. 2-30 asked for, and Duke provided, 5-minute aggregate solar and load data for DEP and DEC for April 2016 through August 2018.

deviation of the DEP intra-hour variability for July 2018 was 9.7 MW. The hourly average standard deviation of the DEC intra-hour variability for July 2018 was 3.6 MW. If short-term variability scaled linearly as the *Ancillary Service Study* claims, then the hourly average standard deviation of the short-term variability for the net Duke system would be expected to be 13.3 MW (9.7 + 3.6). Instead, the hourly average short-term variability had a standard deviation of only 10.3 MW, just 78% of what linear scaling predicts. The 10.3 MW is also exactly what would be expected for completely uncorrelated short-term variability aggregation for DEP and DEC [square root of (9.7^2, + 3.6^2)].

Examining the increase in short-term variability as the solar fleet grew from April 2016 through July 2018 shows a similar result with short-term variability increasing much more slowly than peak output.

Because historic data shows the expected trend of short-term variability increasing much more slowly than solar capacity as solar penetration increases, the assumption of linear scaling is unjustified.

Q. How did Duke Energy respond to your recommendation that short-term variability of new solar plants should be modelled as uncorrelated?

A. Despite the historical data mirroring the trends that would be expected for uncorrelated short-term variability aggregation for DEP and DEC, the *Ancillary Service Study's* linear scaling of variability assumes perfect correlation of the short-term variability of the new and old solar plants. In response to SACE's initial comments, which explained that solar plant short-term variability tends to be uncorrelated, Duke Energy's reply comments stated:

"Mr. Kirby estimated the discount with the following subjective formula.

$$1 / \sqrt{\frac{\textit{Existing Plus Transition Capacity}}{\textit{Capacity from Historical Dataset}}}$$ [294]

"The formula is not appropriate as it is not based on the observed diversity benefit of increasing solar."[30]

First, the formula I employed is not "subjective"—it is the standard root mean square statistical formula for combining the variability of uncorrelated, randomly varying, entities such as the short-term variability of aggregations of loads, solar generators, and wind generators. Second, as discussed above, this formula models hourly average short-term variability for the Companies' system more precisely than the linear scaling modeling the *Ancillary Service Study* employs. Therefore, it is Astrapé's assumption that short-term variability scales linearly which is unreasonable and out of line with observed diversity benefits of increased solar.

Q. Why isn't the *Ancillary Service Study's* inclusion of solar generation with reduced variability sufficient to account for the aforementioned diversity benefits?

A. The *Ancillary Service Study* states that it did include a case in which "the raw historical data volatility was utilized along with a distribution that has 75% of the raw data volatility to serve as bookends in the study for the "+1,500" MW solar

[30] Duke Energy Reply Comments at p. 106.

scenarios."[31] But these scenarios are not "bookends": they both still vastly overstate the short-term variability for the growing solar fleet. It would be much more reasonable to assume that short term variability of new solar plants is uncorrelated with that of the existing solar plants and with each other. The resulting expected short-term variability per MW of installed solar generation from uncorrelated solar variability would then be:

- 100% for the actual measured solar fleet
- 74% of-the-actual-measured-MW-variability-/-MW-of-installed-solar-generation for the Existing solar generation
- 61% for the Existing + Transition
- 55% for the Existing + Transition + Tranche 1
- 43% for the Existing + Transition + Tranche 1 + 1500 MW

The *Ancillary Service Study* included Existing + Transition + Tranche 1 + 1500 MW cases with 100% and 75% short-term variability when a more realistic assumption is that short-term solar variability will decline to 43% due to aggregation benefits.

Q. The *Ancillary Services Study* included solar generation from thirteen locations throughout the DEC and DEP service territories. Why is that not sufficient?

A. Thirteen locations is not a lot of diversity for 7,630 MW of solar generation in the Existing + Tranche 1 + 1500 MW case. If the simulated solar plants were evenly spread among only thirteen locations that would result in each solar plant being 587 MW and occupying about 3000 acres or 4.6 square miles. It would be much

[31] *Ancillary Services Study* at p. 31.

more realistic to simulate 7,630 MW of solar generation spread over 150 distinct locations, each representing a 50 MW solar plant.

The study did not include even that much diversity, however. Twenty two percent of the DEP solar plants and 24% of the DEC solar plants were modeled at single sites.[32] 78% of the DEP solar and 85% of the DEC solar was modeled at just four sites each. What might appear to be a reasonable attempt at site diversity is, in fact, singularly lacking in diversity.

Even if a 587 MW solar plant covering 3,000 acres were built, it would have a significant reduction in short-term variability compared with existing solar plants simply from its own geographic size.

High quality solar integration studies model realistically sized solar plants that are sited with realistic geographic separation. The *Ancillary Service Study* fails to do so.

Q. How do the best integration studies model higher penetrations of wind and solar generation than currently exist?

A. The best studies have sub-hourly solar or wind data that is time-synchronized to actual load data. This is because weather drives wind, solar, and load. The best solar and wind integration studies use mesoscale atmospheric numeric modeling to generate five- or ten-minute wind and solar data, at specific locations for every

[32] *Id.* at pp. 22-23.

proposed wind and solar generator, for a number of historic years.[33] The solar and wind data is then synchronized with actual measured load data covering exactly the same historic time period. This assures that diversity benefits as well as coordinated behavior are appropriately modeled. The best studies utilize reliability metrics that approximate actual NERC reliability requirements.

Because the *Ancillary Service Study* did not follow the practices of good integration studies the Commission should not accept the study results as proposed by Duke and should not find the proposed integration charge reasonable.

III. THE IDAHO POWER STUDY PROVIDES A BETTER MODEL FOR CALCULATING INTEGRATION COSTS

Q. In your report, you refer to a 2016 Idaho Solar Integration Study as providing a "feasible approach" to modelling variable renewable generation integration in a realistic way. Please explain why.

A. The Idaho Power Study studied variable renewable generation integration (solar and wind). The Idaho Power Study is a better model because it (1) employed production cost modeling with reserve requirements adjusted to maintain pre-solar-and-wind reliability levels; and (2) targeted reserves sufficient to compensate for 99% of the 5-minute balancing deviations—in other words it allowed a cumulative 90 hours per year of deviations. This methodology, while

[33] *See, e.g.*, Eastern Wind Integration and Transmission Study, NREL/SR-5500-47078, February, 2011 and Western Wind and Solar Integration Study Phase 2, NREL/TP-5500-55588, September 2013

still more conservative than the actual NERC balancing requirements, allowed the Idaho Power Study to more realistically model variable renewable generation integration. I recommend that the Commission relies on a study that more closely resembles the Idaho Power Study in order to more accurately calculate any appropriate solar integration charge.

Q. Mr. Wintermantel compares Idaho Power's incremental operating reserve requirements with those calculated for DEC and DEP. Is this an accurate comparison?

A. No. Mr. Wintermantel included a Figure 7 in his Direct Testimony that shows the MW of required additional reserves plotted against the MW of solar generation. Based on this figure, which shows that at low levels of solar penetration (800 MW and 1,500 MW of solar) the incremental load following reserves required by the Idaho Study is comparable to the load following reserves required by Astrapé's *Ancillary Service Study*, Mr. Wintermantel concludes that the $\text{LOLE}_{\text{FLEX}}$ metric is "reasonable and appropriate."[34] This conclusion is not sound because Idaho Power's peak load is only 3,400 MW compared with 20,600 MW for DEC and 14,000 MW for DEP, and as discussed above, the *Ancillary Service Study* predicts exponentially increasing cost of integrating incremental solar with the conventional fleet.[35]

Furthermore, variable renewable penetration (wind plus solar) in the Idaho

[34] Wintermantel Direct Testimony at p. 31, ll. 1-11.
[35] *Id.* at p. 20.

Power study was 67% of peak load compared with 5% to 33% penetration for Duke. Had integration requirements been plotted based on solar penetration percentage it would be clear that Duke's proposed solar integration charge is significantly higher than Idaho Power's at comparable levels of renewable penetration. Figure 1 below compares Idaho Power's additional reserve solar generation requirements with Duke's based on penetration level, and illustrates that DEC and DEP's additional operating reserve far exceeds Idaho Power's even though Idaho Power is experiencing far higher rates of renewable penetration.

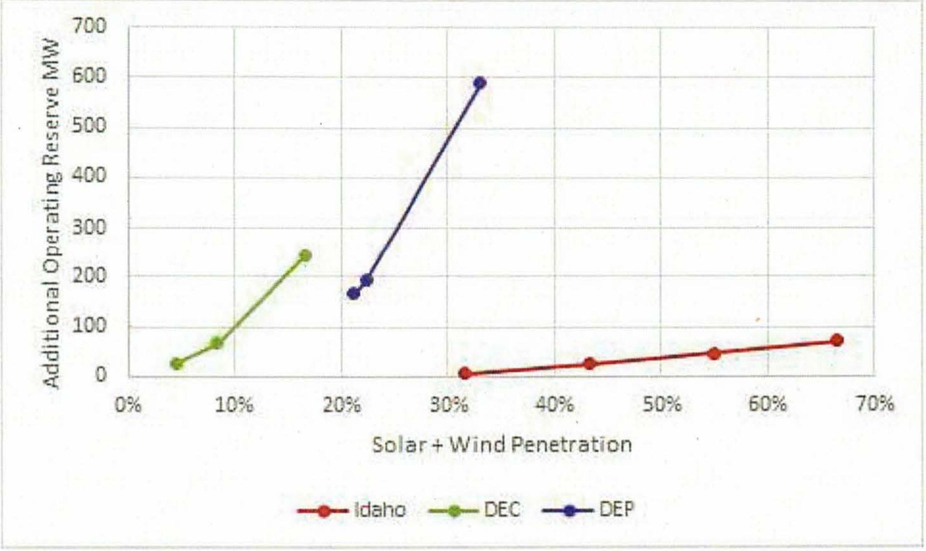

Figure 1: Idaho Power's additional reserve requirements compared to DEC and DEP's additional operating reserve

Figure 2, below, demonstrates that the integration costs calculated for DEC and DEP also dramatically exceed the integration costs calculated in the Idaho Power Study, even though Idaho Power is experiencing significantly greater renewables penetration.

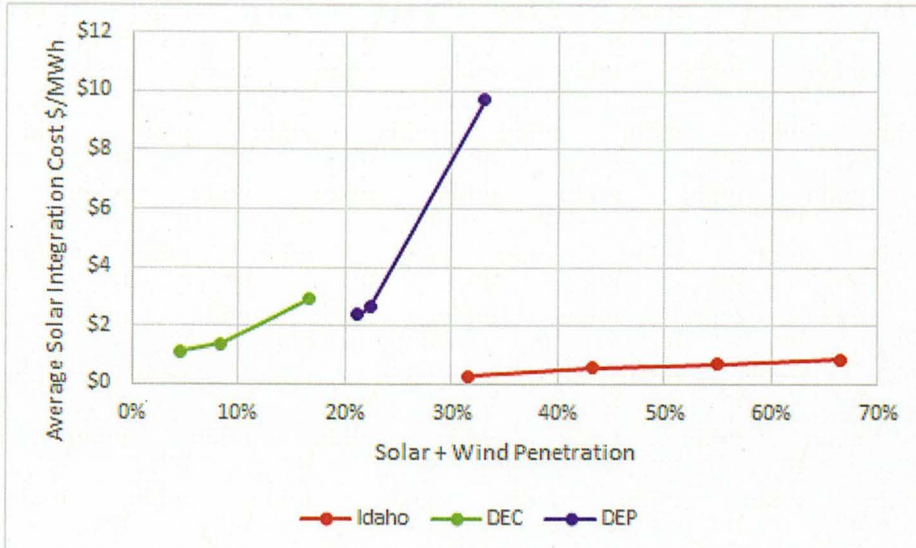

Figure 2: Idaho Power's calculated solar integration cost compared to DEC and DEP's calculated solar integration cost

These figures illustrate that reserve requirements and integration costs calculated in the *Ancillary Service Study* far exceed those calculated in the Idaho Power Study for much greater rates of solar and wind penetration. In other words, Mr. Wintermantel's statement that the Idaho Power Study validates the conclusions reached in the *Ancillary Service Study* is misleading and inaccurate.

Q. Why did Idaho Power find that it could relatively easily integrate 67% wind and solar generation penetration while the *Ancillary Service Study* concluded that the Companies will face significant integration costs at much lower levels of solar penetration?

A. A major difference in the integration analysis performed by Idaho Power and the *Ancillary Service Study* is the reliability metric. While the *Ancillary Service Study* used the fictitious 1-day-in-10-year $LOLE_{FLEX}$ short-term balancing requirement, Idaho Power targeted reserves (in both the base and renewables cases) sufficient to compensate for 99% of the 5-minute balancing deviations. That is, Idaho Power allowed a cumulative 90 hours per year of deviations rather than one-event-in-10-years. Idaho Power's modeling reliability metric is still very conservative but is much closer to the actual NERC reliability requirements and consequently results in a more realistic assessment of solar generation integration requirements.

Q. In Reply Comments, Duke Energy argued that the 99% confidence level used in the Idaho Power Study is no less stringent than the LOLE$_{\text{FLEX}}$ 1-day-in-10-year balancing requirement used in the Astrapé *Ancillary Service Study*. Is this accurate?

A. No. The 99% confidence level used in the Idaho Power Study is less stringent than the LOLE$_{\text{FLEX}}$ 1-day-in-10-year balancing requirement used in the *Ancillary Service Study*. The LOLE$_{\text{FLEX}}$ reliability metric used in the *Ancillary Service Study* allows only a single 5-minute imbalance in ten years while Idaho Power's reliability metric allows 90 hours of imbalance per year. In other words, the LOLE$_{\text{FLEX}}$ metric used in the *Ancillary Service Study* requires balancing that is over 10,000 times stricter than the 99% confidence level used in the Idaho Power study.

Duke Energy claims that the LOLE$_{\text{FLEX}}$ balancing requirement is not as draconian as it seems because load deviations counteract solar deviations in some intervals and that DEP and DEC systems already have excess flexibility during some hours.[36] But these same points regarding flexibility and load deviation are inherent to any basic production cost modeling, including the Idaho Power Study, so they cannot be used as a means of distinguishing the balancing requirement in the two studies.

More importantly, the $LOLE_{FLEX}$ 1-day-in-10-year balancing requirement is completely unrelated to the mandatory NERC balancing requirements, which also apply to each BA's net load.

IV. DATA QUALITY ISSUES IN THE *ANCILLARY SERVICE STUDY*

Q. Please describe your concerns with potential solar output data quality issues adversely impacting Duke Energy's solar integration analysis as articulated in your Report.

A. In my Report, I discussed *possible* dropouts and data anomalies in the solar data underlying the *Ancillary Service Study*.[37] Because analysis of regulation requirements is much more sensitive to data dropouts than energy or capacity analysis, I devoted several pages of my report to analyzing the raw output data that Duke Energy supplied in response to data requests.

[36] Duke Energy Reply Comments at pp. 100-02.
[37] *See* SACE Initial Comments, Exhibit B at pp. 15-19.

Q. Have your concerns regarding the presence of potential solar output quality issues been addressed?

A. Yes. In Reply Comments, the Companies acknowledged that raw output data must be carefully scrubbed prior to regulation analysis and stated that Astrapé did scrub the output data it received from Duke Energy prior to regulation analysis.[38] This addressed my concerns about the potential for dropouts and data anomalies.

Q. Why did you previously believe that the data Duke provided to Astrapé had not been scrubbed?

A. Duke Energy characterized my assumption that the *Ancillary Service Study* relied on unscrubbed data as "unreasonable."[39] However, my belief that the data Duke Energy provided to Astrapé had not been scrubbed arose from misleading responses to SACE's data requests.

SACE Data Request 2 Item 2-27 explicitly asked for sub-hourly output data from *individual* solar plants covering the same time period that the Astrapé *Study* was based upon.[40] Duke Energy refused this data request, responding that the data was not accessible:

> Duke Response to SACE Docket No. E-100, Sub 158 Avoided Cost – 2018 SACE Data Request No. 2 Item No.

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[38] Duke Energy Reply Comments at pp. 111-12.
[39] *Id.* at p. 11.
[40] SACE Data Request No. 2, Item No. 2-27, Docket No. E-100, Sub 158. ("Please provide actual, 1-minute generation output of all QF solar across DEP and DEC's territory for 2018 year to date, as well as 1-minute aggregate load data for each system. If possible break down DEP in east and west regions. Please provide data in aggregate, as well as plant data (if available).").

> 2-27: "[T]he Companies object to SACE's request to have the Companies prepare or gather data and analysis that is not reasonably available and/or does not exist and therefore would be unduly burdensome to create. The aggregate data consists of nearly 200 individual sites, each of which would have to be retrieved separately at one-minute granularity. … Please refer to the attachment provided in the Companies' response to SACE DR 2-30, which includes five-minute granularity aggregate data".[41]

Note that the Data Request asked for both aggregate data and individual plant data. Duke Energy substituted 5-minute aggregate solar output data for 1-minute aggregate solar output data (which was fine) but did not provide any individual solar plant data, stating that the individual plant data was "not reasonably available and/or does not exist". This omission is significant <u>because a lack of individual solar plant data makes it virtually impossible to scrub the solar data or conduct a valid regulation analysis.</u>

Based on Duke Energy's response, which stated that the individual solar plant data was "not reasonably available" or did not exist at all, it was reasonable to conclude that Duke Energy did not provide Astrapé with data from individual solar plants. Otherwise, Duke Energy's response would have misrepresented, or at least obscured, the true availability and existence of the data SACE requested. Since Astrapé could not have fully scrubbed the solar data without date from individual solar plants, I was reasonably concerned about the presence of data dropouts and anomalies in the data, and how they would have affected the

[41] *Id.*

Ancillary Service Study's conclusions.[42]

V. DUKE ENERGY AND THE PUBLIC STAFF'S STIPULATED INTEGRATION SERVICES CHARGE CAP

Q. Is the stipulated proposal to cap future increases to the integration services charge based upon Duke Energy's calculation of incremental ancillary service costs appropriate?

A. No. As explained previously, Duke Energy's integration cost calculations are already over inflated, especially for higher solar penetrations. Additionally, Duke Energy's proposed integration charge is based on average costs. Presumably future integration charge proposals will also be based on average, rather than marginal, costs. It makes no sense, then, to set a cap based on the inherently higher marginal costs when future rate adjustments will be based on average costs.

VI. DOMINION'S INTERMITTENT GENERATION RE-DISPATCH CHARGE

Q. Do you have concerns with Dominion's proposed re-dispatch charge?

A. Yes, a primary concern continues to be the lack of details that Dominion has provided concerning the re-dispatch charge calculations.

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[42] In response to a similar data request in DEC and DEP's pending South Carolina Avoided Cost proceeding, the Companies responded by providing the one-minute generation output from individual plants. DEC and DEP Response to SACE and CCL First Data Request 1-19, Docket 1995-1192-E-1. It is unclear why the Companies considered this data reasonably available in the context of the South Carolina proceeding, but not in this proceeding.

I am also concerned that Dominion did not include analysis of the benefits that distributed solar provides to the power system in their development of the proposed re-dispatch charge.

Q. Mr. Petrie states that Dominion is now willing to eliminate the 80 MW solar penetration level from the analysis. Is this appropriate?

A. Yes, I was originally concerned that the proposed re-dispatch charge was based on analysis of inappropriate levels of solar penetration. Solar penetration is already 823 MW in the study region and is expected to be 965 MW in 2020 and 1,063 MW in 2021.[43] Inclusion of the 80MW Scenario in the re-dispatch calculation is inappropriate because the low-solar-penetration results dominate the calculated cost. Removal of the 80 MW solar penetration scenario alleviates this concern.

Q. Mr. Petrie states that Dominion is now willing to base its proposed re-dispatch cost calculation on the "all costs" category and not to average in the other categories. Does this alleviate your concerns?

A. Mr. Petrie's statement partially alleviates my concerns. It is worrisome that Mr. Petrie states that "[t]he Company continues to believe that its initial approach to calculating the re-dispatch charge was appropriate". It is reasonable to perform analysis under different sets of assumptions in order to better understand what

[43] Virginia Electric and Power Company's Report of Its Integrated Resource Plan, p. 212 (May 1, 2018).

conditions contribute to specific results. It does not make sense to average results from different types of conditions such as "All Costs" and "No PJM Purchases/Sales". Similarly, pumping costs and revenues should either be included or not. It is hard to imagine how it makes sense to average a "No Pumping Costs/Revenues" case with three other unrelated cases. Hopefully this analysis approach will not reappear in the future.

VII. Conclusions

Q. Can you summarize your recommendations for the Commission?

A. Yes. The analysis methodology presented in the November 2018 Duke Energy Carolinas and Duke Energy Progress Solar *Ancillary Service Study* is deeply flawed, and the resulting solar integration charges are unjustified. As a result of the deficiencies I discussed above, the solar integration costs developed in the *Ancillary Service Study* do not reflect actual increased reserve requirements or actual impacts on the operating costs that the Companies will likely experience as a result of increased solar generation. The analysis method and tools should be updated to reflect actual utility reliability requirements and operations. The solar data should be reanalyzed to reflect plant and system aggregation benefits. Errors in calculated reserve requirements will only get worse as expected solar penetrations increase. Reliance upon the $LOLE_{FLEX}$ reliability metric, islanded analysis methodology, and linear scaling of solar generation short-term variability should not be allowed in this or future integration studies.

Q. Does this conclude your testimony?

A. Yes.

BY MS. BOWEN:

Q. Thank you. Mr. Kirby, did you prepare a summary of your testimony?

A. I did.

Q. Would you please give your summary to the Commission?

A. Madam Chair, members of the Commission, my name is Brendan Kirby. I am an electric power systems consultant. My business address is 12011 Southwest Pineapple Court, Palm City, Florida. I am a licensed professional engineer with a BS in electrical engineering from Lehigh University and an MS in electrical engineering, power system option from Carnegie-Mellon University.

I have 44 years of experience in the electrical utility sector, 15 of which were spent at the Oak Ridge National Laboratory where I was a senior power systems researcher. I spent a year providing technical support to the Federal Energy Regulatory Commission as it established the mandatory reliability standards. I was a FERC representative on the initial NERC reliability readiness audits of control areas and reliability coordinators. I coauthored an amicus brief cited by the United States Supreme Court in its January

2016 ruling confirming FERC's demand response authority. I have been consulting full-time since 2007. I have testified in proceedings regarding wind and solar integration, bulk power system reliability, ancillary services, and demand response before Commissions in Georgia, California, Minnesota, Texas, Wyoming, Hawaii, and before the FERC.

I thank the Commission for the opportunity to participate in this important proceeding. I am here to testify on behalf of the Southern Alliance for Clean Energy. In my testimony, I address several aspects of the solar integration charge proposed by Duke Energy Carolinas and Duke Energy Progress, and included in the proposed Stipulation of Partial Settlement filed on May 21, 2019, on behalf of Duke Energy and the Public Staff. My testimony also addresses the solar redispatch charge proposed by Dominion Energy of North Carolina.

In my testimony, I explained that Duke Energy's proposal of the proposed solar integration charge does not accurately represent the actual cost of solar integration. The ancillary service study underlying Duke Energy's proposed integration charge has significant errors, each of which results in the study overestimating the Companies' load-following requirements and artificially inflating solar integration cost projections. First, the study uses an LOLE FLEX reliability metric that is unrelated to mandatory NERC reliability requirements and is considerably more stringent than Duke Energy's actual operating reliability requirements. Second, the study models DEC and DEP as isolated power systems instead of modeling them as they actually operate as part of the Eastern Interconnection. Third, the study incorrectly assumes that short-term variability of new solar generation scales linearly. Due to these errors, the solar integration costs developed in the ancillary service study do not reflect actual increased reserve requirements or impacts on operating costs that the Companies will likely experience as a result of increased solar generation. Furthermore, since the study inaccurately concludes that the integration charges must exponentially increase as the solar penetration increases, the flawed methodology could be used to impose exponentially increasing integration charges upon solar developers when they are not justified.

My testimony also discusses Dominion's

proposed redispatch charge. My primary concern with Dominion's proposed redispatch charge is that Dominion analyzed only the costs, but not the benefits, of distributed solar. I recommend that Dominion be required to consider the benefits of solar to the grid and factor those benefits into any proposed redispatch charge.

In conclusion, I respectfully urge the Commission to reject Duke Energy's proposed solar integration charge and the Stipulation of Partial Settlement regarding the charge. The Commission should not allow Duke Energy to use inflated and inaccurate projections of reserve requirements and operating costs to penalize and discourage development of solar qualifying facilities. I further recommend that the Commission reject Dominion's proposed redispatch charge until Dominion recalculates the charge based on both the cost and the benefits of integrating solar.

Q. Thank you, Mr. Kirby.

MS. BOWEN: Madam Chair, Mr. Kirby is now available for cross examination.

CHAIR MITCHELL: Mr. Dodge.

CROSS EXAMINATION BY MR. DODGE:

Q. Good morning, Mr. Kirby.

A. Good morning.

Q. Tim Dodge with the Public Staff. So, Mr. Kirby, you were in the room just a few moments ago when I was speaking with Mr. Beach --

A. Yes.

Q. -- and I had asked a question about the Idaho study --

A. Yes.

Q. -- and the PacifiCorps study and whether those systems were modeled as islands.

Did you hear that question?

A. I did.

Q. And do you have any familiarity with either of those studies and whether --

A. Yes.

Q. -- those also were -- whether or not they were modeled as islands?

A. Yes.

COURT REPORTER: I'm sorry. Could you just wait until he finishes his question? Thank you.

Q. With regard to the Idaho Power study that you cite in your testimony, was it modeled as an island?

A. That gets to a very important point. And let me explain. We are using -- I think we are using the term island and power system in two very different ways. When I speak about the -- when I am concerned that the Astrape study modeled the power system as an islanded power system, I am speaking of a physically islanded power system where you disconnected all the ties to the outside, where the system is not connected to the Eastern Interconnection. The Astrape study requires five-minute balancing with no -- well, it requires the balancing area's generation to match the balancing area's load for every five-minute interval.

When Mr. Beach was talking about an islanded power system, he was talking about whether you could have transactions with your neighbors. And let me try and make sure that distinction is very clear. I am -- my concern is that it would be fine to model the power system and say that the balancing area is not having any commercial interactions with its neighbors, no transactions coming in and going out. A power system that is connected to the Eastern Interconnection but that is having no transactions with its neighbors -- no energy transactions, no ancillary service transactions, no reserve transactions -- that power system still has to meet the NERC balancing requirements. So NERC sets the standards, and it would be perfectly reliable if it meets those standards. If that balancing area were to physically disconnect, to physically operate as an island, then the NERC balancing standards would not be sufficient. A system that had to island and stand on its own would collapse if it tried to meet -- tried to operate on only the NERC standards.

So when I am concerned about the system being modeled as an island, it's concern that the system was modeled as a physical island. And my point -- the major point of my concern in my testimony is that the reserve requirements for a balancing area that is connected to the Eastern Interconnection, even if it has no transactions, the mere fact that it is connected to it greatly reduces the short-term balancing requirements that that balancing area needs to meet, and makes it such that the NERC balancing standard requirements are adequate to maintain reliability.

Q. Thank you for that explanation.

And with regard to the Idaho study, do you have a copy of that solar integration study with you?

A. I do. I do.

Q. On page 17, it talks about the design of the simulations.

A. Yes.

Q. So the second paragraph under the design of simulations description it indicates that the Idaho Power generating a transmission system as it exists at the time of issue of this report is assumed for the production cost simulations, and then it lists the generating resources that are assumed.

So those are -- that's what it limited its -- the available operating reserves for purposes of the integration report, those resources?

A. Yes.

Q. Okay. All right. Thank you. And are you aware of any other solar integration studies around the country, particularly with vertically integrated utilities that have taken different approaches with the islanding, physical or for reliability purposes?

A. No. No utility that I'm aware of has done -- no credible study that I'm aware of has done a study for -- a utility that is interconnected has done a study that assumes physical islanding.

Q. All right.

A. Utilities, of course, that are islands, they must do the study that way.

Q. Okay. Thank you. So I would like to ask you a couple of questions about your direct testimony, the Figures 1 and 2 in your direct testimony. This is on page 37 and 38.

A. Yes.

Q. All right. You were -- in these charts, you are comparing the penetration rates for solar and wind for Idaho versus the additional operating reserves required in the Idaho Power study versus the Duke integration studies. Now, you have -- the right column talks about -- I'm looking at Figure 1 first, on page 37. This is additional operating reserves and megawatts required.

And, again, that's just for solar, or is that for solar and wind?

A. I believe these are the added reserve requirements just for the solar.

Q. Okay. But your chart for Idaho Power includes the solar and wind penetration?

A. Yes, because they are having to deal with much more variability than -- they are dealing with very high penetrations of variable generation.

Q. All right. And so if we were looking just at solar instead of including the wind portion here, would the amount of additional operating reserves be as significant as you indicate here? Would it shift more to the left?

A. Well, the red line would shift somewhat to the left. I can't remember the exact percentages, but -- well, maybe it's in here. It was in my report.

(Witness peruses document.)

So the penetration for solar alone is still higher, I believe, than for DEC or DEP, but the -- then they have -- you know, they are forced to deal with the even greater version of having the wind as well.

Q. Okay. So looking at Figure 2, this deals with the average integration costs?

A. Yes.

Q. And again, the same -- you have the solar and wind penetration percentages along the x-axis, and you've got the average solar integration costs on the y-axis. The -- in terms of -- what you're comparing there is you have, again, for DEC/DEP, minimal winds, so you have just shown the solar, but you've shown for Idaho the larger penetration includes solar and wind --

A. Yes.

Q. -- but only the cost for the solar; is that correct?

A. I believe that's correct, yes.

Q. Okay. Are you familiar with what the integration costs are -- estimated average integration cost for wind would be in Idaho?

A. I am not. Though, I will say that, as you -- as we have seen in other studies, the incremental cost tends to be higher. And here, solar was the incremental on top of an already large amount of varying wind. So Idaho was being forced to deal with the variability of solar, not as its first variability, but after its dealing with the loads variability and the winds variability, and now solar was added on top of that.

Q. All right.

MR. DODGE: May I approach the witness?

CHAIR MITCHELL: You may.

Q. Mr. Kirby, what I have shared with you is a copy of the wind integration study report from Idaho Power.

This is dated February 2013, but is it your understanding that that's the most recent wind integration report that Idaho Power has?

A. I do not know.

Q. Okay. Subject to check, would you agree that this is the most recent --

A. I have no idea.

Q. Okay. All right. I tabbed one page in this. I believe it's page 7. I just wanted to share the wind integration costs. These are average costs that came out of this study, but looking at the table on page 7, it indicates for the three different levels of wind penetration the average integration cost would be $8.06 at 800 megawatts, $13.06 at 1,000 megawatts, and $19.01 at 1,200 megawatts; did I read those numbers correctly?

A. I see that.

Q. Okay. All right. So if you added those integration costs of the wind for your Figure 2 to show the average integration cost for solar and the wind, that we would have to adjust the scale on that chart, wouldn't we?

A. Sorry. I want to pull that back out.

(Witness peruses document.)

I'm sorry. What's slowing me down is to check for -- I don't recall if this study -- I'm not seeing anything saying that this study had a technical review committee, and the significance of that is that the Idaho solar study, which was done in I think -- yes, 2016, so it would be three years after this study, did have a technical review. So they had an outside group of experts -- independent experts who reviewed the study methodology and the study results. Most importantly, the study methodology.

Q. And I -- I'm sorry, go ahead.

A. And the significance would be -- just a speculation, but the reason the technical review committee would have been brought in for the solar study was because of concerns with the methodology. And I, of course, have not looked at the methodology used in the wind study to see if it is the same methodology that was used in the solar study. So I agree with you that the numbers that are reported here are as you said. Whether those numbers are comparable, I could not say without more review of the study.

Q. Sure. And I certainly appreciate that. And I think, also, to the point that there is going to be some overlap likely in some of those -- the way you would look at the integration costs with solar and wind combined versus two separate reports looking at two different simulations.

A. Well, the wind report is likely before there was significant solar. So the wind report would be a -- probably an analysis of standalone -- or of the wind resource wouldn't -- the solar wouldn't have been there. The solar report, of necessity, had to include wind, because wind was -- just as load was in the system at the time, wind was in the system. So you can't look at the solar by itself.

Q. All right. Thank you. So I wanted to make sure also I understand your perspective on the LOLE FLEX standard. I recognize your position that it doesn't align with the NERC BAAL standards or the CPS2 standard.

Do you agree that it does reflect a measure of increased intra-hour volatility between the base case and the change case?

A. No. The metric, itself, does not reflect a difference between a base case and a change case. The study methodology does. And the study methodology of using a production cost model that's based on security constraint, unit commitment, and economic dispatch, and running production costs and hourly production cost modeling, subhourly production cost modeling over a range of time, that's a very -- it's now an established methodology for conducting integration studies. So that methodology does, indeed, look at a without-solar and a with-solar cost and compares them.

The metric, the LOLE FLEX, no. It's simply a metric that looked at whether the power system had enough ramping capability every five minutes to match the movement and load, and that's -- that's just a metric of ramping capability versus net load of volatility, and it's not related to -- there is no requirement in the NERC standards. NERC does not see that that is -- has any impact on a system reliability.

Q. But in terms of the relationship you just stated, the net load of volatility and ramping capability, that there is a -- in terms of being in compliance with the standards, that is an important relationship; you agree?

A. Could you please restate the question?

Q. To the extent you described as a measure of net load volatility and the ability of the resources of the ramping capability of existing resources, aren't those two related, in terms of how a utility would be able to comply with reliability standards?

A. The LOLE FLEX metric is not.

Q. In terms of the volatility, okay. But if we don't refer to LOLE metric, the intra-hour volatility and ramping capability, the relationship between those two factors.

A. Yeah. Intra-hour volatility is important, yes.

Q. Okay. All right. So if the intra-hour volatility increases, does that have the potential to decrease --

A. Oh, yes.

Q. -- reliability and the need for additional operating reserves?

A. Yes.

Q. Okay. All right. No further questions. Thank you.

CHAIR MITCHELL: Okay. We are gonna take a break, and we will come back on the record at 11:35.

(At this time, a recess was taken from 11:05 a.m. to 11:38 a.m.)

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

MR. DODGE: Chair Mitchell, this is Tim Dodge with the Public Staff. If I could briefly, during my cross examination with Mr. Kirby I provided him a copy of the Idaho Wind Integration Study from 2013. And, initially, I just indicated to confirmed the dollar amounts in -- that were included in his table, but if I could, I would like to make the copies of that available as a cross examination exhibit for Mr. Kirby. Copies are being made right now, and I'll have the distribution momentarily.

MR. BREITSCHWERDT: Mr. Dodge, actually, I have copies. I would be glad to pass them out. They are a Public Staff cross exhibit. It seems like something we are all gonna talk about today, so we made copies.

MR. DODGE: If you have copies available.

MS. BOWEN: So, I'm sorry, just for clarity, are we introducing it as a Public Staff cross exhibit, or is Mr. Breitschwerdt gonna wait to do it?

MR. BREITSCHWERDT: Public Staff is fine.

MR. DODGE: If we could introduce that wind integration study as Public Staff Kirby Cross Exhibit Number 1.

MR. BREITSCHWERDT: I'm sorry, Mr. Dodge, you said wind integration study?

MR. DODGE: Yes.

MR. BREITSCHWERDT: I apologize. We

have the solar integration study.

MR. DODGE: Okay. So we will have copies downstairs momentarily for distribution.

CHAIR MITCHELL: Okay. Would you like to go ahead and introduce it at this time?

MR. DODGE: If that's acceptable.

CHAIR MITCHELL: How would you like that exhibit to be identified?

MR. DODGE: If the 2013 Idaho Power Solar Integration -- Wind Integration Study, I'm sorry, could be marked as Public Staff Kirby Cross Examination Exhibit Number 1.

CHAIR MITCHELL: Okay. And with -- do you want to go ahead and move it in at this time?

MR. DODGE: Yes, please.

CHAIR MITCHELL: Okay. Without any objection, we will go ahead, and the motion is allowed, Mr. Dodge.

MR. DODGE: Thank you.

(Public Staff Kirby Cross Examination Exhibit Number 1 was admitted into evidence.)

CHAIR MITCHELL: So I believe it's Duke's.

CROSS EXAMINATION BY MR. BREITSCHWERDT:

Q. Good afternoon, Mr. Kirby. Good morning still. I guess we are pushing afternoon quickly. Brett Breitschwerdt on behalf of Duke Energy. How are you today?

A. Doing well. Yourself?

Q. Doing well. And you have been here all week; is that correct?

A. Yes.

Q. So you have heard the Duke panel that testified earlier this week, and then from Mr. Wintermantel who sponsored the study on behalf of Astrape?

A. Yes.

Q. Okay. Thank you. So I would like to start out with a few, kind of, basic questions just to confirm understanding I think some areas of agreement.

So would you generally agree with Mr. Wintermantel and the Astrape study that a utility that is managing a system that is integrating solar is gonna have to plan for and respond to greater volatility than a system that does not have solar installed in the system?

A. Yes.

Q. Okay. And so your testimony doesn't dispute the fact that there is a cost associated with that volatility and that there is an increased cost associated with adding solar to the system; is that correct?

A. Correct. It's possible that the cost is so low that it's not worth the Commission's time, but yes, there is going to be cost.

Q. And so talking about the Progress system that by 2020 is gonna have 3,000 megawatts of solar -- uncontrolled purpose solar on the system, fair to say that that is not an immaterial cost and something that should be quantified and something that should be assigned to the cost cause?

A. Well, I agree that that's -- that's a good amount of solar, and it's certainly something you want to study and you want to look at. Until you correctly and accurately look at it and determine what the cost is, you don't know what the cost is. So -- but I would agree there will likely be a cost. It's possible that that cost would be so low that it is not worth the Commission's time to impose a separate charge for it.

Q. And you would agree with me that that cost is being caused by the addition of the uncontrolled solar --

A. Yeah.

Q. -- to the system and that volatility -- not a problem. My questions may be a little long, so not a problem. So the addition of that uncontrolled solar and the associated volatilities causing that cost; do you agree with that?

A. Yes.

Q. Thank you. So turning now to the Astrape study, I think one area where I see conceptual agreement between your testimony and the study is this concept that a solar integration study should quantify the cost incurred by the utility to integrate the variable resource in the utility's system while maintaining the same level of reliability before and after the -- I think we are focused on solar here -- the variable solar energy is being added to the system; is that correct?

A. In general, yes. I would qualify that slightly, and only after hearing the whole week of discussion. Here's my qualification. If you had a system, say, that was -- you know, obviously doesn't exist -- if you had a system where the load was just perfectly smooth, so there was no variability whatsoever, and then you were to add -- and you say, well, that system is having a fine time, just no problem at all for it to meet the NERC BAAL standards. And you add a bunch of solar, and wind, anything else, a variable load comes in, and suddenly the system has got some variability in it. It would not be appropriate to then say, for that system, just because it had no variability before, that it must have no variability after. So it's a subtle distinction, but the reliability rule should be the same before and after.

Q. So let me -- I think you said, on page 2 of your affidavit, that, in developing such a study, in order to make a fair comparison, it's necessary to hold reliability constant in the no-solar and solar generation case; would you accept that as your testimony?

A. That is what I said, and what I was trying to add was a slight clarification to that that, you know, if someone were to pick that apart and say, well, I want to hold -- I happen to have a system that had very high reliability -- excessively high reliability before, I now want to hold that after, that would not be appropriate.

Q. And you have no indication that the Duke utilities are taking -- retaining excessive -- bringing excessive operating reserves on the system or managing their systems in a way that's imprudent or to promote excessive reliability; is that correct?

A. That is correct. Most good utilities operate their systems where they are watching their BAAL and CPS1 scores, and they deliberately -- they, obviously, want to meet reliability. They want to be very reliable. They fully meet the standards. So they will hold their scores. They will put on enough reserves to keep their scores so they are fully reliable. If they find that their reliability scores are too good, they will back off on the reserves they are carrying. Because if your score is too high, you are wasting money.

So, in actual operations, it turns out it is a -- as a modeler, it is a good thing to go and true up to look at actual operations and see how a system was operating, and that's good, because the system operators will -- they have incentive to, and they do a good job of bringing their systems to the right level of reliability. Now, as Mr. Beach said, you can't take that, you know, at every instant in time, because at times you will have a system operator who sees a changed condition, he decides to carry extra reserves, because he thinks the system may be more stressed. And so for a period of time, until learns whether this new condition genuinely does create the added stress, there may be excess reserves, and the CPS1 and BAAL scores will reflect that. But as a general rule, over a length of time, you will find that well-run systems have CPS1 and BAAL stores that are appropriately better than what NERC requires.

Q. So thank you for that. I'm gonna try and keep my questions narrowly tailored, since we are being efficient here, just to keep the back and forth more expedient.

MS. BOWEN: And, Madam Chair, just on that, we certainly allowed the Duke witnesses and Dominion witnesses time to fully answer the questions.

MR. BREITSCHWERDT: I'll be careful to make sure my questions are tailored in such a way that the answers -- and please feel free to elaborate, and your counsel can help you elaborate on redirect as well.

Q. So I would like to focus on the NERC

standards that you speak to in your testimony. You extensively discussed the NERC reliability standards, and you just mentioned the control performance 1, CPS1; is that the acronym that you use? And then the BAL-001-2 reliability standards?

A. Yes.

Q. And those are generally the balancing standards? Can I use that terminology for short?

A. Yes.

Q. And you heard Mr. Wintermantel's testimony yesterday where he agreed that these are the standards that the system operators must meet to balance the system and regulate frequency; do you recall that?

A. Yes.

Q. Okay. And you agree that that's appropriate and that's what is required --

A. Yes.

Q. -- in real-world operations?

And so in your testimony and affidavit you challenge the Astrape study for not attempting to more closely model these balancing standards, correct; that's the general premise of your testimony?

A. Yes.

Q. And would you either agree or accept, subject to check, that both Duke and Astrape have represented to the Commission and through testimony that, to their knowledge, no utility across the country has conducted an integration services charge -- or I guess an ancillary service study that has been used to support integration service charge that's designed to model these balancing standards; do you agree with that?

A. The difference is how closely one gets. It -- I do agree, and I stated in my report and in my testimony, that it is not currently possible to perfectly model the BAAL requirements, the NERC reliability standards. And the reason for that is the balancing requirements, themselves, depend on what the -- what system frequency is. And system frequency is not a function of just any one utility, it's what all of the aggregate Eastern Interconnection is.

Eastern Interconnection is roughly 720,000 megawatts, and frequency is above 60 hertz when there is more generation than what the aggregate load is, and it's lower when there's less. And the NERC reliability standards require -- only require balancing -- or only penalize a balancing area when it is -- when its generation-to-load ratio, when it is hurting system frequency. So NERC penalizes you if system frequency happens to be high and you are over-generating, then the NERC balancing standards wake up and say that's bad. Similarly, a frequency is low and you are under-generating. So what makes the modeling difficult is you would have to model perfectly the entire Eastern Interconnection. You can't do that, but you could get surprisingly close. And my concern is the LOLE FLEX metric does not get anywhere near close.

Q. Thank you. So to reiterate your testimony in your affidavit here today, is that continues to be infeasible, to directly model the BAAL standards, as you commented on extensively in your testimony?

A. Yes. It's infeasible to model them perfectly.

Q. In your testimony, you also take issue, in small comment, but make the point, that Mr. Wintermantel, in the study -- Astrape, in the study they developed, they pointed to the earlier control performance 2, or CPS2, standard which was replaced in July of 2016 with the BAAL standard, BAL-001-2; is that right?

A. Yes.

Q. He said yesterday that was an oversight. And would you agree with me that the manner in which the

Astrape study undertook the modeling, it did not take into consideration the CPS2 or the BAAL standard, so it had no impact on the modeling that that older standard was identified?

A. Yes. However, I think it is significant that you can look at the history of NERC's balancing requirements, and you find -- the reason that's important is we have seen a very clear and large progression towards NERC recognizing that instantaneous balancing is not required -- is not helpful to maintaining overall system reliability. So the first -- NERC first came out with balancing -- it was a guideline -- they happened to be called A1 and A2 -- back in the '70s. And, at that point, there was a requirement that says each balancing authority must force its ACE, it's area control error, it must force that match between load and generation, it must force it to cross zero every 10 minutes. So the driving force in what you had to do, in terms of balancing, the system operator had to watch, and if he was under-generating, he had to force his generation to rise and to cross zero to get those two to match. And it's not gonna just stay there, it's gonna shoot across. Had to do that every 10 minutes. And if he was running high, he had to come down. Well, NERC recognized that that was not useful to system reliability.

So why is that? Well, it's because if the system frequency happens to be low and you are over-generating, well, you're helping to bring that system frequency up. So they really didn't want you to go on and say, well, system frequency is low. I'm helping to improve reliability for the interconnection, but I'm being forced by the A1/A2 standards to reduce my generation and cross through zero. Well, we recognize -- as an industry, we recognize that just didn't make sense. So in 19 --

Q. Mr. --

A. If I may, please.

Q. Please.

A. In the mid-'90s we adopted CPS1 and 2. Those recognized the balancing that the A1 and A2, forcing -- forcing balancing every 10 minutes was not a useful thing. Notice that was still every 10 minutes. CPS1 and 2 then said, look at the long-term average. They also then had the CPS2 which said, yeah, and you better look and keep a shorter term, the CPS2 requirement, on the 10-minute average. You better watch that as well.

You move another 20 years, and we recognize that, no, that was not helpful to reliability. So we moved over to a standard now with CPS1, which looks at an annual average of the balancing, and then we looked at the BAAL part of that standard, and that puts a requirement in based on system frequency, again, only if you are hurting system frequency, you must come into balance, and it's a 30-minute criteria. So if you are out -- if you are hurting interconnection reliability for 30 minutes, you've got to come back across. Anything shorter than that, you do not. And even there, it's not cross zero, there is a megawatt number you have to hit. So the point to all of that is that the balancing standards to maintain interconnection reliability, which is what NERC cares about, which is what DEC and DEP have to operate to, does not require five-minute balancing.

Q. Thank you. And again, I will try to keep my questions more discrete. That was very helpful, and actually you answered two questions along the way there, so we are making progress.

A. We are ahead.

Q. Well, I wouldn't go that far, but we are making progress. Let's just -- I mean, the history was helpful to the Commission, I hope, and I think the key point is between the CPS2 standard that was replaced in July of 2016 and occurred in current BAL-001-2, is it fair to say that the new standard is significantly more restrictive? You went from having a monthly assessment of 10-minute average deviations, and now the system operators required, on a 30-minute basis -- 30-consecutive-minute basis, to ensure they maintain compliance with the updated standard; would you agree with that?

A. No, I would not. It is significantly less restrictive, and we are a slow industry. It takes us a long time to adopt a new standard. So the BAAL standard was under development -- I cannot recall the exact -- but it was years that it was under development. And a wise part of the development process is we have some utilities operate under the new BAAL standard while it's being tested. So this goes on for years. While that testing was going on and the standard would then come up for voting, an interesting quirk of this particular standard was the utilities who were in the test -- the test was scheduled to end -- refused to switch back to the old CPS1 and 2 standard. They refused to switch back because they were saving so much money, because it's so much easier a balancing standard to meet. And they pointed out rightly that, hey, this standard is better for reliability and it is significantly less restrictive, and it saves us a bunch of money. And so then the standard finally did get passed. It just took us, as an industry, a while to look at those results, to vote on them, and to decide they were acceptable, and then to get FERC to adopt the standard.

Q. So just so I'm clear and the Commission is clear, it's your testimony that the CPS2 standard, which you said was first created when, in the '90s?

A. It was in the '90s, yes.

Q. And then in 2016, as the industries evolved --

A. Yes.

Q. -- NERC established a less restrictive standard --

A. Yes.

Q. -- in passing the BAL-002 [sic], and the difference between the two standards at a high level is that the CPS standard did a monthly evaluation of averages with 10-minute deviations, and the BAL-002 [sic] standard requires compliance every 30 consecutive minutes; is that correct?

A. I would not characterize it that way, no.

MS. BOWEN: Also, Mr. Breitschwerdt, can we make sure we are looking at the same standard? So are you referring to the one that was introduced yesterday as an exhibit?

MR. BREITSCHWERDT: Yes, ma'am. That's the current standard. Thirty-minute compliance.

MS. BOWEN: And, Mr. Kirby, do you need a -- do you have a copy of that too?

THE WITNESS: I do. I have a copy of it. The only problem is that --

MS. BOWEN: And, I'm sorry, Mr. Breitschwerdt, that says -- the one that you have is 001-2; is that what you have?

MR. BREITSCHWERDT: That's correct.

MS. BOWEN: And it's not 002? I'm sorry. We've just gotten some confusion here. I want to make sure we're all looking at the same thing.

MR. BREITSCHWERDT: It's 001-2.

MS. BOWEN: Great. Thank you.

Q. I think I can withdraw the question. I don't think there is a lot more to go on there, but it's your testimony that it's less restrictive, and that, between 1990 and 2016, NERC was formed, presumably, and then established a less restrictive standard for 2016?

A. No. NERC was formed after the 1964 blackout. So NERC is much older than that. I'm sorry, I got caught on the date.

Q. That's okay. So could you look at page 16 of your testimony, please, starting at line 18?

A. I'm sorry, page number again, please?

Q. 16.

A. Yes. And line number?

Q. Starting on 18. So I will read it to you while you're finding it. So, I mean, you are speaking here about the CPS2 standard, and you are making the point that monthly average 10-minute imbalances were required, and that the DEC system was required, under that prior standard, to maintain 92 megawatts of load following, and then the DEP system was required to maintain compliance of 17 megawatts 90 percent of the time, and you make the point that this CPS2 standard, which Mr. Wintermantel in the Astrape study inadvertently referenced, allowed deviations for over 5,000, 10-minute intervals?

A. On a going-forward basis, that's no longer the standard.

Q. Why did you inform the Commission that it was 5,000 10-minute deviations; why was that a helpful metric to put out there in the record?

A. The reason I put it out there was because, as I read the Astrape report, it talked about the CPS2 metric, and so it says, okay, here's what the reliability requirement is. Now we are going to use this LOLE FLEX, because we don't want to -- you know, we are unable to model to the CPS2. And so the point of my example here was to show that LOLE FLEX does not -- it's not a reasonable representation of what CPS2 requires.

LOLE FLEX is saying you can only have one five-minute deviation in 10 years, where a CPS2 was allowing 5,000 10-minute intervals, so 10,000 five-minute intervals every year, whereas LOLE FLEX said you get one in 10 years. The point being that the difference between the LOLE FLEX metric and CPS2, and even more so with BAAL, is they are just phenomenally different in terms of their balancing requirement. There is nothing in NERC that says you have to be able to balance every five minutes and you get one five-minute deviation in 10 years. It's completely unrelated to what's required.

Q. And just so I'm clear, is it your understanding of the Astrape study that they assumed one five-minute deviation from the NERC standards in 10 years?

A. My understanding of the Astrape study is that the methodology looks at the currently online ramping capability on a five-minute basis, and it looks at the net, gross -- the aggregated load in solar's ramping movement over that five-minute interval, and in the 10 years, if it finds one five-minute interval where there is not sufficient ramping -- online ramping capability from the generation, that that becomes an unacceptable violation. You are allowed one. So one would be acceptable, two would be unacceptable violation.

Q. And would you agree with me that the LOLE FLEX metric is not as conservative as a frequency deviation that you would have to manage under the NERC standards, and that they were modeling the NERC standards, so at 0.1 -- one violation in 10 years under LOLE FLEX would not be representative of a NERC frequency deviation that would violate the standard?

A. I don't think I'm following your question, because I would say that the LOLE FLEX is a much, much more stringent requirement.

Q. Okay. Let's -- so I think you spoke to that in your testimony. So maybe just to return to your testimony quickly, you made the point here on page 16 that there were 5,000 10-minute deviations allowed under the old CPS2 standard, but you didn't identify under the current standard that Duke operates under today, the BAL-002 [sic], how many deviations were allowed; is that correct?

A. Well, if you are looking just at 10-minute deviations, you can have as many as you want. BAAL -- you know, that's -- yeah. The BAAL standard -- the BAAL part of the standard only wakes up and penalizes you -- obviously, system operators are not gonna do this, but it only imposes a penalty when you hit 30 minutes of imbalance that's hurting a system frequency.

Q. So to the stringency of the standard -- I think if you turn to page 39 of your testimony, please, I want to cover that -- you said, on page 39, that it's your view that the LOLE FLEX metric requires -- that Astrape utilizes requires balancing is over 10,000 times stricter than the 99 percent confidence level that's used in the Idaho Power study; are you familiar with that?

A. Yes.

Q. And that's your opinion, that the standard is 10,000 times stricter than what the Idaho Power study used?

A. The LOLE FLEX, which requires that -- which looks for one -- which has a limit of one five-minute imbalance in 10 years, yes, it's 10,800 times tighter than a standard that allows for 90 hours a year. That's 900 hours of imbalance is allowed in -- from the Idaho study, 900 hours imbalance would be allowed in 10 years, and the LOLE FLEX metric says nope, one instance of five minutes is all you get instead of 900 hours.

MR. BREITSCHWERDT: Chair Mitchell, I would like to introduce a cross examination exhibit at this time.

(Pause.)

CHAIR MITCHELL: Mr. Breitschwerdt, let's go ahead and mark for identification.

MR. BREITSCHWERDT: Thank you, Chair Mitchell. So I would mark this as DEC/DEP Kirby Cross Examination Exhibit Number 1.

CHAIR MITCHELL: Shall be so marked.

(DEC/DEP Kirby Cross Examination Exhibit

Number 1 was marked for identification.)

Q. So, Mr. Kirby, I think -- have you had a chance to review the exhibit?

A. Yes.

Q. Okay. And did you have an opportunity to review Mr. Wintermantel's direct testimony in this proceeding?

A. I did.

Q. And would you accept this is -- subject to check, this is a modified version of his Figure 7, which is a comparison of the operating reserves that were required under the Idaho Power study at various penetrations, operating reserves relative to?

A. Subject to check, yes.

Q. Okay. So --

MS. BOWEN: And I'm sorry, Mr. Breitschwerdt, this is not -- just to be clear, this is not the chart that is in Mr. Wintermantel's testimony. This is developed after the filing of that testimony, based on that.

MR. BREITSCHWERDT: That's correct, and I was going to talk him through that.

MS. BOWEN: Okay.

Q. I think the arrows and the numbers on this chart are added, but the -- somewhat for informational purposes, just to make it clear -- but the underlying chart, itself, the dots on the chart going across, are representative.

MS. BOWEN: I'm really sorry. The original chart that this is based on, can you just confirm where that is for the witness' purpose?

MR. BREITSCHWERDT: Sure. It's at the bottom of the figure. In the exhibit, it says Duke Progress Wintermantel Direct at 14. We could turn to there now.

MS. BOWEN: And it's Figure 3? Do we have that right? I apologize. I just want to make sure -- and, basically, we are wondering if you mean Figure 7 or --

MR. BREITSCHWERDT: Yes. It's Figure 7 of his direct testimony.

MS. BOWEN: And it looks like it's on page -- his direct, page 31, rather than 14. Please confirm that so Mr. Kirby knows where he's looking. Again, we think this has been derived from Figure 7 on page 31 of Mr. Wintermantel's direct testimony.

MR. BREITSCHWERDT: That's correct. And

I will amend the exhibit, just if you will mark on there please that it's from page 31 of his direct and not page 14 in the footer, that would be helpful.

MS. BOWEN: Thank you.

Q. So I think we were having a conversation a moment ago, Mr. Kirby, about your statements in your testimony that the LOLE FLEX metric used in the Astrape study, in your opinion, is 10,000 times more conservative than the methodology or the metric that is used in the Idaho Power study --

A. Yes.

Q. -- is that correct?

And how familiar are you with the Idaho Power study? Were you involved in the development of that study?

A. No.

Q. Have you reviewed it closely?

A. Yes.

Q. And is it your general position, regarding the results of that study -- or let's start with the methodology -- the methodology used in that study, the methodology was reasonable?

A. Yes.

Q. And the metric that was used was reasonable, in your opinion?

A. The metric, itself, is actually a little conservative, but yes, it was much more reasonable.

Q. In your opinion, the results of the study, in terms of the load following operating reserves that were required, is it your opinion that those results were also reasonable?

A. As far as I know, the study appears to have been performed well, and it had a much more reasonable metric, so the results are probably reasonable, but I had no ability to, you know, verify the accuracy of the modeling.

Q. Okay. And so looking at this exhibit that I have placed in front of you, would you accept, based on your review of Mr. Wintermantel's testimony and your review of the Idaho Power study, that this represents comparison of the operating reserves that were required to integrate solar into the Idaho Power system and then the Astrape study's requirements for the Duke Energy Carolina system and the Duke Energy Progress system as those studies added penetration of solar over time?

A. I think it's important to realize that the Idaho Power study was looking at a very different -- it was looking at solar integration, but it was looking at a different impact that solar has on the system. So the -- in my testimony, where I was focusing on was the fact that Idaho Power chose a reliability metric that was 99 percent balancing requirement. And my point was that that's much, much closer to approximating the actual NERC balancing requirement. So that's my real point of focusing on that study.

But if you go further and then say, well, what did they find and why did they find it, well, in Idaho, what they were looking at was not five-minute ramping. What they were looking at was the difference -- the hour-ahead solar forecast error. So it was the uncertainty in solar based on -- from an hour before they were looking at what solar was forecast to be, and what was the worst deviation based on looking at five-minute intervals, how far off was solar based on an hour-ahead forecast. And so what they were quantifying was the reserves needed to compensate for the hour-ahead forecast error. What the Astrape study was looking at was did the -- did the balancing area have enough ramping reserves to follow every five minutes.

So whether you come up with the same number or not is irrelevant. They are looking at two totally separate impacts. And, in fact, it would be completely unreasonable, then, to come back and say, oh, well, here's the results we found for needing five-minute ramping requirements. Oh, we never looked at hour-ahead solar forecast error. Now we want to add that in too. You could do that on each individual component and then come up with a really high integration charge.

So my point in all of that is that the question about whether the megawatts of reserves that the Idaho study calculated for a specific megawatt amount of solar happened to be the same as the megawatt amounts required for parts of the study for a much different sized balancing area is not relevant.

Q. Well, let's just establish that the results are highly correlated; would you agree with that?

A. I would agree with you that, when you plot them on this graph with these axes, the dots happen to fall reasonably close together.

Q. I mean, it's more than that. If you look at the Idaho Power study, and they are integrating 400 megawatts of solar, which is the base level for that study required 6 megawatts -- and I will talk through this, and please interject if you disagree with anything I'm saying -- but for adding the 800 megawatts, they found that 24 megawatts of operating reserve were required, the base level which was used for integrated service charge in this proceeding for Duke Energy Carolinas, they said to integrate the 840 megawatts of solar, it required 26 megawatts. So highly correlated 800, 840, 24 megawatts, 26 megawatts, continued, and I think Mr. Wintermantel did this yesterday, he kind of established a curve going up on his graph to show that, logically, as you add more solar, you need to add more operating reserves to address that volatility and going out over the curve you get --

MS. BOWEN: Mr. Breitscherdt, what is the question? And it may be helpful to break it up so that Mr. Kirby can follow what you are getting at, because that was a lot. If you followed it, Mr. Kirby, that's fine, but I would like the question.

Q. I could slow this down and ask individually.

So would you agree that the Idaho study has operating reserves measured in yellow on here had 400, 800, 1,200, and 1,600 was the amount of solar they proposed at the system in their production cost -- their hourly production cost modeling as explained?

A. What I would not agree with is that that in any way says that if you took the DEC and DEP systems and applied the Idaho study methodology and performed the analysis -- the Idaho analysis for the DEC and DEP systems, that you would -- that that, in any way, implies that the Idaho methodology would come up with that same reserve requirement when applied to the DEC and DEP generation solar and load.

Q. But you would agree with me that the results are highly correlated and they are appropriately reflected here?

A. I'm troubled by your use of the word "correlated," because "correlated" implies that there is some connection. So no. I will agree with you -- yes, I will agree with you that the -- those specific results for Idaho measured only in terms of solar megawatts and incremental operating reserves are -- have values that are close to the Astrape results for the DEC and DEP. I don't think that -- for a lot of reasons, I don't think that that actually means much.

Q. So let's go back to the -- you were speaking about the --

COMMISSIONER GRAY: Please pull the mic a little bit, please.

MR. BREITSCHWERDT: Yes, sir.

Q. You were speaking about the modeling in the Astrape study and the metric used, and I was reviewing your testimony. Page 14, line 20, you take issue with or make the comment --

A. Let me get there, please.

Q. Sure.

A. My testimony?

Q. Yes, sir.

MS. BOWEN: Can you give the lines and page one more time, please?

MR. BREITSCHWERDT: Sure. Page 14, line 20.

THE WITNESS: I'm slow. One more time, the page and line.

Q. Page 14, very bottom of the page. And it's --

MS. BOWEN: Mr. Kirby's testimony?

MR. BREITSCHWERDT: Yes.

MS. BOWEN: I'm not seeing a line 20. Page 14 of the direct.

MR. BREITSCHWERDT: If you will allow me

a moment, I will -- excuse me, line 19. I apologize.

MS. BOWEN: Thank you.

Q. So you make the comment that Duke has not disputed through the reply comments the fact that the actual balancing requirements were based -- were not based on the actual NERC standards, which you agree is -- can't be modeled at this point, and were based on the -- what you characterized as the invented LOLE FLEX metric; is that accurate?

A. Yes. I have said that you cannot model the -- you cannot duplicate the CPS1 and BAAL perfectly, but you can get close.

Q. And isn't it true that the hourly production cost modeling that the Idaho Power study undertakes is similarly an invented metric that was designed by the modelers?

A. Which got very close -- which got much closer to the NERC requirements.

MR. BREITSCHWERDT: And, Chair Mitchell, I would like to introduce the Idaho Power solar integration study from April 2016, if I could, please, as an exhibit.

Q. Mr. Kirby, you have a copy of this?

A. I do.

CHAIR MITCHELL: Let's mark it for identification purposes.

MR. BREITSCHWERDT: Thank you, Madam Chair. So this would be Duke Progress Kirby Cross Exhibit Number 2.

(DEC/DEP Kirby Cross Exhibit Number 2 was marked for identification.)

Q. So I think maybe I'm drawing an inference, but it seams like you're suggesting that the Idaho Power hourly production cost modeling was intentionally designed to meet those NERC balancing standards.

Is that a fair inference or not a fair inference?

A. I think -- yes, of course, the -- it's the NERC balancing standards that tell a utility what balancing it has to do. So that is the reality that -- the balancing area is going to have enough reserves and operate them such that it meets the NERC balancing requirements. They are not going to go and meet some other requirement. You know, once the standards are vetted by the industry, and accepted, and then adopted by FERC, you say, well, that's what we operate to. So the BAL-001 standard for the realtime balancing under normal conditions is a performance standard. The balancing area needs to meet a certain level of balancing, and neither NERC nor FERC cares what reserves are required. You have to --

Q. Mr. Kirby --

A. I'm sorry, can I just finish that? You have to have enough reserves on so that you -- so that you are meeting the NERC standard. So that is what -- there is nothing in the standards that say what that amount of reserves are. So when you go as a modeler and want to model one of these systems, you are having to come up with a proxy that gets you to modeled reserves that reasonably approximate what the real system operator has to have available, and what the real system operator is being driven by is the NERC standards. I apologize that that was so long.

Q. I just wanted to make clear. So I have reviewed the Idaho study, and it doesn't reference the NERC standards, it doesn't reference -- or it doesn't -- do you agree that it doesn't reference the NERC standards -- it doesn't reference the BAAL -- it doesn't -- it's April 2016 study, correct?

A. Yes.

Q. That's the date on it?

A. Yes.

Q. So, as of April 2016, CPS2 was the standard in effect, correct?

A. I'm not sure. And the reason I'm not sure is I don't know if Idaho was one of the utilities that was operating already under BAAL, because a number of utilities -- quite a few utilities have been operating under BAAL for several years, and as I mentioned, they wouldn't give it up because it's so much cheaper. So I'm not sure which it was to. And my response, no, it does not surprise me at all that the study does not reference the NERC standards. Fundamental to all of our analysis is that what's driving how we operate power systems is we operate to the NERC standards. So you normally don't go and bother to reference that.

Q. So your premise is that you are critiquing the Astrape study for a modeling methodology that is a five-minute intra-hourly methodology versus an hourly production cost modeling methodology that Idaho used. And while we are recognizing that the Astrape study doesn't model specifically to the BAAL standards, you're saying that's okay, that the Idaho study also didn't recognize that it wasn't modeling to the BAAL standard either, and it was fine that they didn't reference it, but, presumably, it was modeling to those standards; that's your testimony?

A. My testimony is that Idaho's selected metric of requiring 99 percent balancing, that does get much closer to the NERC balancing requirement than the LOLE FLEX metric does. And while I would agree with you that I can't recall either anywhere in the Idaho Power study where they specifically said that -- you know, they reference CPS1, CPS2, or BAAL -- that what was driving them was to meet the NERC standards. And I'd further say that, if they were driving to something else -- if they were driving to something -- if they were driving to something that was less stringent than what NERC requires, then they wouldn't be reliable, and that wouldn't be acceptable. If they were driving to something that was more stringent than the NERC reliability requirements, then they were wasting money, and their Commission would not have allowed it.

Q. And do you have any basis to infer that the Duke utilities, based on the Astrape study, will be procuring operating reserves that are in excess of what is identified in the Astrape study, and that would be excessively reliable?

A. No. And, in fact, that is my point. I think that I have a tremendous respect for the way Duke operates their power system, and I believe that they will continue to operate and to be watching their CPS1 and BAAL scores, and so that they will operate such that that is what they meet, and they will not operate to something -- to a much more stringent or different standard. Consequently, a study that looks at what would the costs be to meet a different standard is -- it's not relevant, because they would never incur those costs.

Q. All right. Would you agree with me that both the Astrape study and the Idaho study are essentially quantifying production cost differences, in terms of increased load following ancillary service requirements between parasimulations in a base case and a change case?

A. Yeah. I would agree that the basic methodologies of the two studies, being production cost models that are based on security constrained unit commitment and economic dispatch under hourly models covering a lengthy period and that do without-solar and a with-solar study as a comparison, that the two methodologies and the modeling tools are very similar. The difference is that the metric that was chosen as the reliability metric was appropriate in Idaho's case and inappropriate in the Astrape study's case.

Q. And the metric that was used in the Idaho study was based on an hourly production cost modeling, and the Astrape study is -- let me -- would you agree with that?

A. No, I would not. The balancing metric in the Idaho study -- it is -- you are correct, in that the Idaho study did its -- it was 2016 -- modeling capabilities have improved since then. So the production cost modeling in the Idaho study, I believe, was done on an hourly basis, and the way they incorp -- but they were focusing on subhourly variability. And in their specific case, they were looking at five-minute intervals also of solar production and looking at the difference between the five-minute solar production and the hour-ahead forecast of that solar production. So they were looking at basically a forecast error, but it was subhourly. It could have happened in the first five minutes, last five minutes, any time in the hour. And from that, they took that imbalance, if you will, and put that back into the hourly production cost study.

So the Astrape study does it by doing --

directly doing five-minute modeling. In Idaho's case, they did it by looking at the five-minute variability and then adding that back in on an hourly basis into the hourly production cost modeling. Two different approaches, but coming to the same -- trying to come to the same basic modeling of with and without and comparing the difference.

Q. And -- okay. So I would like to move to the discussion that you had earlier with Mr. Dodge on, I think, the islanding or what the Astrape study and Mr. Wintermandel's testimony has characterized as neighbor assistance.

Is it fair to say that your testimony takes issue with the manner in which Astrape modeled the Duke and Progress balancing authorities and the assumption that they are solely and fully responsible for providing the incremental load following requirements to support the additional ancillary services or operating reserves that's caused by adding solar volatility to the system?

A. No. I do not take issue with the fact that DEC and DEP operate as balancing areas and that they must fully meet their balancing requirements. What I take issue with is, the way Astrape did the model, it assumes that the DEC and DEP were not connected to the Eastern Interconnection, and therefore, that DEC and DEP operated as a physical island, and that they must meet on a five-minute or faster basis. They must have the generation perfectly able to match the load. So they were looking at the ramp rate. Is the generation that DEC and DEP have capable of ramping to match the load deviation? And that has -- and that would be required for a physical island.

In this case, NERC does not require that any BA have the ability to match every five minutes. If -- that's a basic problem with the name of the LOLE FLEX, the loss-of-load expectation, the metric. There is no loss of load if you are short on ramping ability for five minutes. It just means that there is gonna be flows in or out of your system. And the NERC reliability requirements fully recognize that's gonna happen all the time. So the -- a problem I think we have is that this question of a system operated as an island gets used in two different ways, and I'm probably the only one who is focusing on the fact that the modeling looked at it as a physical island, as though the system operators went and opened the breakers with all their neighbors and were having to then balance the system. Well, you cannot run a BA that's in the Eastern Interconnection, you cannot run it to the NERC balancing authority -- or balancing standards if you are physically disconnected. The balancing standards are built around the idea that you are physically connected to your neighbors.

It's perfectly fine for you to be completely unwilling to ever talk to your neighbors about any kind of transactions of energy or ancillary services. You are gonna meet all your energy on your own, all your ancillary services, all your balancing requirements on your own. That's fine. The NERC standards still apply. And so, in that sense, modeling as an economic island if you will, that's perfectly reasonable. The problem with the Astrape study is it did not only model as an economic island, it modeled it as a physical island, and that is unreasonable. If you were really going to operate as a physical island, you would have to have a lot higher reserves.

Q. So if I understand -- and I think we can -- so you're not taking issue with the point that a utility would have to either provide or purchase firm capacity from another utility, and so from a capacity procurement for operating reserves, modeling as an island is appropriate; you would agree with that?

A. I agree completely that it's perfectly fine to look at -- if you do not have firm transmission available, and you don't have a willing seller of ancillary services, or you don't want to assume that, that's fine. Then you are going to supply those reserves on your own.

Q. Thank you. And so what your focus is is within the intra-hour analysis that Astrape did, that they were not focused on the, kind of, ability of the larger interconnection to allow for changes in frequency within the framework of the BAAL standards; is that fair?

A. I don't think I would say it quite that way. Let me try and rephrase it.

Q. How would you say it?

A. What I would say, my objection is that the Astrape study -- the LOLE FLEX metric of one five-minute inability to have adequate ramping in 10 years is completely divorced from NERC reliability requirements, and those NERC reliability requirements are based on the fact that you are not a physical island, that DEC and DEP are both connected to the Eastern Interconnection. If they were not connected, then I would agree. I've done a lot of work with Hawaii. I was a consultant to the Hawaii Commission. So for a small island system -- we did a bunch of work at the lab with the Alaskan Rail Belt, so I am familiar with physically islanded systems, small systems. You have a completely different set of reserve requirements. So that is where the study is in error, yeah.

Q. Well -- but -- so your premise is, if they are connected to the larger interconnection, that they are able to rely on the area control error, or ACE, that other balancing authorities would be able to push to do to respond to volatility on the Duke system; is that a fair characterization?

A. I would not say it that way. The way I would say it is that, for all of the balancing areas, the whole reason that we interconnect is because when we are interconnected, the balancing requirements for everyone are much lower. The interconnecting is a tremendous benefit for reliability and economics, even if you never transact with your neighbors. The mere fact that you are interconnected means that your -- your balancing requirements -- economically standing completely on your own, your balance, and everyone else's balancing requirements, are much lower than if you were standing on your -- that's why there is no utility in the Eastern Interconnection that is willing to operate as an island.

Q. So, fair point, but is it reasonable to assume that a balancing authority can rely more heavily on its neighboring balancing authorities in the form of allowing increased ACE deviations as incremental solar is added when comparing -- in a modeling study, between comparing the base case scenario and the added solar scenario? Let me rephrase the question and break that up.

So I think what Astrape has done is they treated the Duke system as an island for modeling, and they recognize that you can't rely more heavily on your neighbor. There is a certain amount of reliance on the system in the base case that should be recognized as the utility providing their operating reserves, and they are recognizing that there should not be increased reliance on neighboring balance authorities for purposes of quantifying the operating costs -- the operating reserves cost of adding solar to the system; do you agree with that?

MS. BOWEN: Mr. Breitschwerdt, I know

you tried to break it up. That was still very long. If Mr. Kirby followed it, that's fine, if not, maybe -- yeah.

A. I will take a shot at it. I am completely comfortable with and never -- I agree with the -- I agree with the concept that you -- the purpose of this -- the methodology of this kind of study -- the purpose of this kind of study is to look at what are the -- what are the increased balancing requirements for a balancing authority after you have added a variable renewable, in this case solar. That's perfectly reasonable. I would also agree with Mr. Beach's statement that, if you happen to have an energy imbalance market, if you happen to have -- if you happen to be part of PJM, so you have got their full market structure, all of that is wonderfully beneficial. That's tremendous. But I am not assuming that. I am perfectly willing to accept that the study says, well, those things are not available, so we didn't model them. That's a separate question of should we go and get an energy imbalance market. Perfectly good question. I would support it. I think you should. It's a good thing. It saves everybody a lot of money. Setting that completely aside, it's then a question of -- so it's not a question of leaning on your neighbors and expecting your neighbors to take care of you. It's the fact that, when you interconnect, the balancing requirements for everyone are reduced, and that the model should reflect that, because it's not a question of saying I need to be standing on my own. It's reflecting the reality of the way you operate. An interconnected utility has lower balancing requirements than an island, and the LOLE FLEX metric inherently looks at the system as a physical island, and that's not appropriate.

Q. And I think you had a conversation with Mr. Dodge earlier about that being your perspective, that that's not appropriate.

And just to be clear, your testimony does not identify any other studies that have evaluated a balancing authority or modeled a balancing authority in a non-islanded study; is that correct?

A. When you say non-islanded, what type of island? Are you talking about a physical island or economic island?

Q. We are talking about a physical island.

A. No, no. Because there is no study out there that ever would do that. There's no one -- it's one of those fundamental things that --

Q. Would you agree with me that the Idaho study is an hourly cost production modeling, so they are not taking into consideration intrahourly transactions, similar to what the Astrape study has done here?

A. Transactions? I'm not following you. What type of transactions are you talking about?

Q. Excuse me. Intra-hour volatility and the operating reserves that are required to respond to that volatility?

A. No, I would not agree with you. Very much, very central to the Idaho study, is that it is looking at five-minute variability. It doesn't do it in the production cost model, but it is part of the study, that -- in the last three years, there has been advances in computing capability and modeling capability. Their model was not capable of modeling -- in the production cost model, was not capable of modeling down to the five-minute interval. Is it an improvement to do the direct economic production cost modeling of five minutes? Sure. Do you have to do it? No. It turns out it's perfectly fine to look at what the increased variability imposes on the system, in terms of added variability and added reserve requirements each hour, and then you take that as an input to the model.

So the Idaho -- the tool they had that only works with hourly production cost modeling, even though it was only an hourly production cost model, they did not miss the subhourly variability. The whole reason they did the study was to look at subhourly variability. Subhourly variability and subhourly uncertainty. So they included more.

Q. Okay. So maybe just -- we have been in the weeds trying to understand the different modeling techniques, and just to take it up a level, or five levels, perhaps.

So, essentially, what the Astrape study has done is they recognize that, on the Duke Energy Carolina system, for purposes of quantifying integration services charge, there is 840 megawatts of solar; do you agree with that?

A. Yes.

Q. That is the existing plus transitional?

A. Yes.

Q. And they said that it's the -- to respond to the volatility associated with that uncontrolled 840 megawatts of solar, it's gonna require 26 megawatts

of additional load following reserves; do you agree with that?
A. I'll accept that, sure.
Q. Okay. And do you -- are you aware of any study that would -- that has quantified a lesser amount of load following reserves than 26 megawatts to integrate 840 megawatts of solar on the system?
A. Am I aware of a -- can I quote you the name of a specific study? No. On the other hand, if you were to add 800 megawatts of solar to, say, the PJM system, I would expect that it would be a much lower amount of added reserves required.
Q. For whom? Who would have to add the reserves?
A. I said this was adding it to the PJM system, so the PJM would have to have added reserves.
Q. Right, but the balancing requirements are balancing authority by balancing authority. What we are here to quantify today is not PJM watt, it's what --
A. I'm sorry. PJM -- and I apologize. PJM has changed so many times. I can't remember what the name of the largest unique balancing authority in the -- it's basically PJM. PJM runs a balancing authority,

and it's big.

Q. But it's your testimony that 26 megawatts for -- of additional operating reserves to integrate 840 megawatts of uncontrolled solar is unreasonable or excessive; is that your position?

A. No. My testimony is that the study methodology -- the study metric was wrong. It does not reflect the -- it's not appropriately modeling the NERC balancing requirements. And because of that, the study results -- we can't say anything about the study results. It -- the study -- the study is fundamentally flawed by the use of the LOLE FLEX metric.

MR. BREITSCHWERDT: Okay. Madam Chair, one more cross exhibit, please. If I could mark this as DEC/DEP Kirby Cross Exhibit Number 3.

(DEC/DEP Kirby Cross Exhibit Number 3 was marked for identification.)

Q. Mr. Kirby, I've just handed you another solar integration study that was recently conducted for a Southeastern utility.

Are you familiar with this study?

A. I am not.

Q. You have never reviewed this study before?

A. Do you have reason to think that I have?

Q. I just asked the question.

A. I have got to admit, my memory is not perfect. So, to the best of my knowledge, I have not. But if you have reason to think that I have --

MS. BOWEN: I'm sorry, Mr. Breitschwerdt, can you confirm, is this publicly available? Is it not publicly available? Don't know? I just noted that it's dated February 2019, which is very recent. So I didn't know if that --

MR. BREITSCHWERDT: It is. We will submit to the Commission that this study was developed on behalf of South Carolina Electric and Gas and filed in South Carolina Docket 2019-2-E.

MS. BOWEN: Okay. Yeah. I see the filing now. Thank you very much.

Q. So you're not aware of this study being in existence, Mr. Kirby?

A. I don't believe so.

Q. Well, we will not ask you many questions about it, since you are not generally familiar with it, but if you could flip to page 4 of the study, which is the executive summary.

So study was commissioned -- and I'm just gonna breeze through this quickly -- by SCE&G in order to estimate impact of solar installations on their system and resulting incremental cost. It considers variability integration costs of three different scenarios of solar increasing on the system. Similar concept, operating reserves being required.

Would you -- and it's probably an unfair question to ask you, except subject to check, that this was similarly an islanding study, but --

A. I would not accept that. If someone was doing a genuinely physically islanded system study, I would be amazed and would not expect that study to stand examination.

Q. Well, let's just go through the study approach here briefly.

So if you go down, 336 megawatts of solar being added, 637 megawatts being added, and then 1,044 megawatts; do you see that there?

A. Yes.

Q. Okay. So if you could turn -- and I don't want to spend a lot of time on this, but just turn to page 30 of the study where it identifies the levelized costs that were quantified to integrate.

A. I'm sorry, what page was that?

Q. Page 30.

A. (Witness peruses document.)

Q. Similarly focused on a 2020 year, they quantified an integration cost of $3.52, and then the incremental penetration increasing to $4.04 -- or adding $4.04, followed by an additional $3.96; do you see that?

A. (Witness peruses document.)

Yes, I see that. Okay.

Q. So recognizing that you haven't reviewed this study -- and I'm not taking issue with that or asking you to review it now. I appreciate there is not sufficient time for that. But just would you agree that the ancillary services cost, the integration cost quantified in this study for SCE&G and other Southeastern utilities, are materially higher than the cost that Astrape study quantified for the Duke systems? Would you agree with that?

A. I would -- obviously, I would agree that these numbers are -- even there, I would want to be sure that they were talking about average and not incremental. The Astrape study did have numbers that were higher than this.

Q. In the out years of penetration, correct?

A. Yes. Well, penetration and -- right. So, unfortunately, I'm not -- so your question about are these numbers higher than what --

Q. Since you're not familiar with the study, I will withdraw further questions. I think that's appropriate. So I want to speak with you briefly about the biennial update that is proposed in the stipulation that Duke entered into with Public Staff.

Are you familiar with that?

MS. BOWEN: Do you have a copy of that, Mr. Kirby? If not, we can --

A. I do. Unfortunately, I shuffled my papers.

Q. If we could just assume, subject to check, that the stipulation provides for --

A. I have the stipulation.

Q. Very good. And would you -- if you want to turn to section 5, stipulation provides for a biennial update in future avoided cost proceedings of the quantification of ancillary services costs as well as integration services charges?

A. Yes.

Q. Do you want to take a moment to review that if you feel you need to?

Would you agree with me that updating the integration cost studies would allow the companies to recognize changes in system characteristics, such as fuel prices, changes to the flexibility generating fleet that affects the ability to provide operating reserves at lower cost, as well as changes in solar volatility and diversity assumptions as additional solar is added to the Duke and Progress systems?

A. I think that's great, and I would go further. To that -- I don't recall if in there there was the -- specifically mentioned to go and look at what the Company's experience actually turns out to be, as far as increased operating reserves required to successfully meet the NERC balancing standards. And, you know, that -- and to that, which Commissioners request for that information, I think that is something that should also be added in to say that, okay, every two years we are also going to look -- there is a whole bunch of solar coming onto the system, we are operating a higher level now. Certainly a higher level than what the variability was benchmarked at. And to see how the variability has played out, what the aggregation benefits have turned out to be, and what the reserve requirements have actually turned out to be. Now, I would add one caution to that, is in asking about the -- asking the system operators of how much reserves are you carrying so they know that for every hour, but you want to also tease out and make sure you know how much of that was contingency reserves, and that's fairly easy for them to split out. So they will tell you the spinning reserve and the non-spinning contingency reserves. But then you also want to know their breakdown on the reserves, as far as how much of that is for load following, how much of that is for regulation, how much of that is covering other unknowns that they are keeping reserves for. So it's not a single number, it ends up being a small group of numbers, and you would like to know, how is actual experience played out, so that would very much enlighten the two-year review.

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

CHAIR MITCHELL: Dominion?

MR. DANTONIO: No cross from Dominion.

MS. BOWEN: I have just a few redirect questions, if that's all right.

CHAIR MITCHELL: Okay.

REDIRECT EXAMINATION BY MS. BOWEN:

Q. Mr. Kirby, one of the exhibits that was introduced was the Idaho Power study.

A. Yes.

Q. And I just want to make sure that we are all clear on this. You referenced the Idaho study, and my understanding is that's for a particular reason. Could you explain why that is -- what that was?

A. The reason I referenced the Idaho study is that the Idaho study looking -- I was looking for an example where another study found a more reasonable proxy for the NERC reliability requirements, and the Idaho study of saying, well, 99 percent balancing requirement, that's a much more -- that still is too strict, but that's a much more reasonable proxy.

Q. Great. Thank you. So it's not perfect?

A. It is not perfect.

Q. It is not perfect, but it gets closer to the actual NERC standards?

A. Closer.

Q. Sorry. And the NERC standards are what the utility must actually operate to in real life?

A. Yes.

Q. And then just one more question about this Idaho Power study. Do you still have it --

A. I do.

Q. -- in front of you? Okay. On page 6 there is some acknowledgements. You don't need to speak in great detail to this, but I know Mr. Dodge had some questions for you about the wind study and the solar study, and you talked about technical review committee.

Can you just describe what's on this page very briefly, but just so folks know?

A. On page 6?

Q. Roman numeral. I'm sorry, Roman numeral 6.

A. Oh.

Q. Yeah.

A. Yes, yes. Roman numeral 6 is an acknowledgement, and they are thanking the technical review committee. The technical review committee is a concept that -- I have been on a number of them. It's a very neat concept. And DOE has been very generous in supporting these. So if you are going to do a study, especially a study that introduces a new concept, a new study method, a new metric, or that, say, for the first time you are looking at solar -- you looked at wind before -- DOE has looked at that and said this is an advance -- in this study is potentially an advance in the analysis technique that, if it's good and it works out and it's done well, we hope it will get propagated to the industry. So DOE tends to then sponsor a technical review committee. And it ends up being an important -- so you look for a group of experts, and you don't want them hired by the utility. Not that you don't want them hired by the utility, you don't want them hired by anybody that's a participant in the study. You want them to be genuine independent technical experts, but somebody's got to pay the motel bill and the flight and whatnot. So DEO steps in and they are willing.

So you see here there is a couple of my colleagues: Michael Milligan -- Dr. Milligan, Barbara O'Neal, NREL folks, Idaho National Laboratory supplied one, but then, you know, you've got some other folks as well. So this is a group of technical experts that then are involved with the study right from the start, and they get together and meet every month, every couple of months. If not physically meeting, they will have a conference call. And whoever is conducting the study -- typically the utility -- then presents, okay, here's what we are trying to do, here's the methodology we are proposing to use, here are the tools we are proposing. They lay that all out, and the technical experts then opine on whether they think that's appropriate and any improvements that need to be made. And so it's an interactive process. And by the end you get -- you either get or don't get the endorsement from the technical review committee, and if the technical review committee endorses it, then everyone else kind of gets the feeling that, all right, the way the study was done was a good way to do the study. So it typically has impact outside of just that one, say, specific rate case.

Q. And just for my confirmation, presumably, they would have looked at, for example, the metric -- the reliability metric that was used?

A. Absolutely.

Q. And this is the reliability metric that you say is closer to the actual NERC standards than what Astrape has done in this case?

A. Yes.

Q. Okay. Thank you.

MS. BOWEN: And then on the handout -- that Dominion Energy handout -- I don't -- I don't think I missed this, I don't believe you moved it into the record, and I would actually say that Mr. Kirby hasn't seen it, doesn't know what it is. It's publicly available. I would say we could take judicial notice of it, or you could stipulate that it's in the public record, but --

MR. BREITSCHWERDT: We did move it as Cross Exhibit 3.

MS. BOWEN: You did? I might have -- did you move it as cross exhibit?

MR. BREITSCHWERDT: Or marked it for review.

MS. BOWEN: And maybe I'm out of time for this, which is fine, but if I'm not out of time, I would object to it and say it's more appropriate for --

CHAIR MITCHELL: There has been no motion at this time.

MS. BOWEN: So let me let the record reflect my objection, but I think it's publicly available. If you need to reference it in filings, you could take judicial notice. That would be my recommendation. So I would ask that it not be entered into the record.

CHAIR MITCHELL: It has not been moved at this time.

MS. BOWEN: Okay. So wait to hold my objection. I understand. My apology. Okay. I think that's all I had. Thank you.

CHAIR MITCHELL: We are going to take a 10-minute break, and we will be back at 1:10.

(At this time, a recess was taken from 12:59 p.m. to 1:12 p.m.)

CHAIR MITCHELL: All right. Let's go back on the record. We will take questions from the Commission.

MS. BOWEN: Madam Chair, if I may, I'm sorry, one matter. I have spoken with opposing counsel with the cross exhibit, the Dominion Energy study, and I believe Mr. Kirby maybe has seen it before but couldn't -- it was hard for him to confirm that just getting it on the stand like that. So if they do want to introduce it into the record, which I believe they do, we will withdraw the objection.

CHAIR MITCHELL: Okay. Thank you.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Kirby, good afternoon. I've got a few random questions, and they really are disconnected, because I've come up with them here listening to you. But I want to just be sure I've got you identified correctly.

You were -- were you one of the coauthors of

the NRAL technical report titled "Operating Reserves and Variable Generation"?
A. Sounds right.
Q. August 2011?
A. Could be. And I'd be -- if you'd like, I could confirm that.
Q. I just got the cover page, and it's some background reading to educate myself, and I -- you had the same name?
A. No. Well, that's absolutely me, yes.
Q. That's you?
A. As you have seen, trying to remember a document from that many years ago, you have to --
Q. You had a lot of publications in your CV, and that was one that I had come upon independently on my own as background education, and I just wanted to make sure it was you.
A. That is me. And my apologies for it.
Q. As I say, I have some random things, and nothing very extended. At the end of the cross examination, you were being asked about the biennial update proceeding that Duke has proposed to adjust their systems integration charge, and I think you said that that was -- I don't want to put words in your

mouth, but sort of a positive thing, even though it didn't solve the problems that you identified, but it was a positive thing for you to do that?

A. Yes.

Q. And you suggested that we -- that as part of that biennial update, that we need to get reporting on the different categories of reserves that Duke has actually maintained over the biennium, broken down by different categories and reserves, and I think you were referring -- I saw you gesture, you were referring to the question that Commissioner Brown-Bland asked yesterday of Mr. Wintermantel, and I pushed her to ask for more. So you were suggesting that that question that she asked Mr. Wintermantel yesterday, that that be segmented by category reserves, right?

A. Yes.

COMMISSIONER CLODFELTER: So I would say to Duke's counsel, I hope that they would take it as a friendly amendment to Commissioner Brown-Bland's question to Mr. Wintermantel yesterday that, when we get that data about the 2015 reserves, that it also be broken down by category. Okay?

MR. BREITSCHWERDT: Specifically?

COMMISSIONER CLODFELTER: Well, we asked for 2000 -- we expanded it to 2014 to the present. All I'm getting at is, Mr. Kirby suggested we ought to see that as an aggregate number of all category reserves, but we ought to see regulating reserves, load following reserves, and contingent reserves, and so on. And I just wanted to amend the request from yesterday, if that's agreeable. Okay?

Q. So, Mr. Kirby, back to you. Do you think, in connection with the biennial update proceeding, it would -- if we do this -- again, if we do this, we will have a biennial update. If we do have a biennial update, is there any kind of information we ought to also be looking at at the -- what I call the historical score cards, NERC score cards that the Company has had over the two years; should we look at those?

A. Yes. I mean, that's always a good thing to look at as well. It's pretty much no problem. They have got to keep those --

Q. Got to keep them.

A. Got to keep them anyway. And I would be amazed if you didn't find that they keep CPS1 scores and BAAL scores that are a little conservative but not a whole lot conservative.

Q. And let me stay with that for a minute, because that's gonna take me to another place I wanted to talk to you about. So your -- without having made the study of the matter or look at any data, your expectation of a well-managed company would be that they would not vary too far from the standards, in terms of their actual performance?

A. Yes, because --

Q. A little conservative, but not too conservative?

A. Yes.

Q. All right. Let me tell you where that takes me. In Mr. Wintermantel's testimony on page 17 -- I don't expect you to have it in front of you. I will read what he says. He says that -- and he's referring here to the use of the LOLE FLEX 0.1 metric, and he says the level of reserves which actually achieve the LOLE FLEX 0.1 year -- events per year was similar to the average reserves actually supplied by the total DEC and DEP systems in 2015 prior to significant solar penetration being integrated. As I understand that, and as I understood his testimony yesterday, what he's saying is that they -- that that metric -- that that metric, LOLE FLEX 0.1, produces -- when you run it through the model, actually produces the reserves that Duke, in fact, historically had before they had a lot of solar penetration.

And so, if that metric yields the actual historical result of the reserves that Duke had, and if we're assuming for the present without having studied the matter that those were probably a little conservative but not excessive, then if we are simply using that metric to model out into the future, why aren't we sort of hitting it pretty close to the target? Why isn't that metric a pretty good surrogate for where we ought to be? If we end up with a comparable level of reserves after solar penetration, and it meets that metric at that point, why aren't we really where we need to be, in the sweet spot with the NERC standards?

A. Yes. And that's a very good question. And let me --

Q. And you're gonna give me a very good answer?

A. I'm gonna try.

MS. BOWEN: Mr. Kirby, are you looking for Mr. Wintermantel's testimony?

THE WITNESS: I'm looking for the Astrape report, and I found it, and it will only take me a second to get to it.

(Witness peruses document.)

Or not. Okay. I'm sorry.

MS. BOWEN: We have it right here.

THE WITNESS: I'm sorry. The page reference I had in my head was not the right one for it. So matching -- you know, matching that point is necessary but not sufficient. So there are two concerns. And, unfortunately, I couldn't find the exact reference for it, but the Astrape report says that they adjusted the model -- they calibrated the model to produce an LOLE FLEX of 0.1 for those conditions, all right. Well, I'm not sure exactly what all went into calibrating. So a problem with the calibrating the model to it is you can't say, well, I did a bunch of work to -- I turned all the dials in the model that calibrated it to meet this point, and then come back and say, look at that, the model met that point, and therefore -- you know, therefore, I'm more confident in the model. No. You just said you went and calibrated it in order to meet -- to represent the system at 0.1. So the second point on it being necessary but not sufficient is you're exactly right. That's what -- so that's what you want to do, is to have your model trued up against reality. But it's not just one point. There also can be a slope to the line.

So the concern would be, all right, even if everything was fine and you did manage, for whatever reason, to hit the -- to match the operation of the existing system, now when you go and roll in a whole lot more solar, was that -- was that criteria sort of a brittle criteria where, wow, you add a little more variability and it shoots way up, because it's looking for that one five-minute event in 10 years. Well, maybe you were so flush with ramping capability on your system that, under the existing system, it just wasn't -- you know, wasn't stressed, and it was -- you know, it was very tolerant. You stress it a little bit, and now you have gotten out of -- and now the problem is that that metric looks for one event in 10 years. And that's not -- so --

Q. Well, I understand you don't like it, but it is a surrogate. I think I understand from everybody's testimony that you've got to use some metric that's going to be a surrogate for the actual NERC standards because you can't model them directly. So we are trying to find out how good a surrogate that is. You don't like it, but let me follow up with a question. I understood your answer. I understood -- thank you for the explanation. So let me follow up now.

Suppose we had multiple runs of the Astrape model, and each of those runs -- because now we have had more than just 2015. We have 2016, 2017, 2018. So what if we ran it for all of those subsequent years and actually -- the LOLE FLEX metric actually yielded the actual results -- operating reserves that Duke was maintaining and carrying during those years. Do we get an additional level of confidence that that's a good surrogate, perhaps? Or does it show us, if we are divergent from what Duke was actually carrying, that maybe it's a really bad surrogate, that it was brittle like you say? What would another four years worth of runs do for us?

A. Another four years of runs would be very good. You're exactly right. So that would leave us -- so let's say that you do the modeling and you get -- and you'd have to make sure that you had really a reasonably good span of solar penetration. And I'm sorry, right now I'm drawing a blank of how much change there has been. So if there is enough that you feel like, okay, I'm now looking at a system that is significantly more stressed with added solar, so I'm feeling like I'm really checking, and so if you did that, and the model hit all those points in between, then I agree. You look and say, wow, that's interesting. The model is matching at least the reality we have seen so far. Now you can -- extrapolation is always difficult. You never know, is it gonna break. But I agree with you that would give you confidence. Then you would be stuck in the position of saying, all right, the physical phenomena that it's based upon I know is wrong, and yet it's giving me the right result. How is that happening? So you would have to dig deep to understand why it worked. But I agree with you completely, and, you know, so if you found -- it's the same kind of thing, if you -- you know, you looked at some totally separate variable, the temperature at noon on every Tuesday, and you plotted that, and that gave you the same answer, you would say, wow, isn't that interesting. I have no idea how that happened, but it works. And as long as I'm convinced it works, good enough. But any time you have a model that you don't understand because the physics doesn't seem to match what you know the physics of reality to be -- the modeled physics and the real systems physics, if those don't match, you are always very leery as to will the results be right. On the other hand, you've got lots of history that demonstrates the results are right. Hey, the results are right.

Q. It's sort of like the analogy of when I press the on button here on the iPad it turns on. It always turns on, but I don't have a clue why.

A. Yes.

Q. Let me leave that alone, but stay with the same general topic. I'm not a power systems operator or even have -- I don't even have a background in electrical engineering. So try to use layman's terms and explain to me again -- walk me through why it is that the 99 percent metric used in the Idaho study gets closer to modeling the NERC standards. Tell me how it gets closer.

A. Right. The way it gets closer is it says -- it looks at the balancing, the matching of generation and load, right, and it -- so what the metric is looking at is every five minutes, right, how well did you -- were you capable of matching generation to load? So maybe the solar suddenly drops, and your system didn't have the generation, didn't have the ramping capability or the capacity, either one, and so it failed, in that five-minute interval, to be able to match load, right. Well, coming out with a 99 percent metric, that gives you -- I think it's 90 hours a year that, you know, 99 percent of the -- of the whole year's time it says I could have been out of balance for 90 hours a year.

Well, the important point is NERC -- you know, if your -- if your power system is out of balance -- so you're sitting there, you're operating, your generators are trying to follow their load perfectly, and the load suddenly moves on you, and you fail to chase it, doesn't bother NERC a bit. This happens all the time. And maybe the load dropped and you were over. So the metrics are looking at the -- you know, at longer-term averages of that variability, and then for -- you know, obviously, if you do this for -- you know, if you say, well, I don't care. They give me a lot of flexibility. So I'm gonna -- I'm out of balance, and I'm sitting there -- well, it wouldn't be loss of a generator, because then the other standards come in, but for whatever reason, I'm lazy today. I'm just not gonna run -- I'm not gonna run as much generation as I should.

Well, at that point, that BAAL metric is watching that, and it wakes up, and it says, by the time you have hit 30 minutes, you are getting a call from the reliability coordinator saying -- and he's gonna call you before that, because he's watching it too. You're never wanting to push these limits right to the edge, but you are not technically in violation for 30 minutes. So that's why the 99 percent, saying I'm gonna do all this long modeling, and if I'm out -- you know, if I'm out of balance for 1 percent, that's fine, but I'm gonna add more reserves if I go out of balance for more than that. And as I say, you know, if you want to more closely match the NERC actual requirements, it's probably looser than that. 95 percent might be more appropriate. But fine, 99 percent, you know, it's pretty close. It certainly beats the heck out of saying I am going to demand that I have the ability to match load every five-minute interval for 10 years, and I could only miss it once.

Q. Okay. You were not -- thank you. Thank you for that. You had several critiques, and I don't remember -- maybe I was dozing off during the cross examination -- but there was one that you -- I don't remember hearing any discussion of, and that was the -- your critique that the Astrape model assumes that, as additional solar is added, that the impact scale up linearly. And you make a critique of that that no, that's not correct, it doesn't scale linearly. So my question to you really -- I understand your testimony, but my question to you is, Mr. Wintermantel testified yesterday that, on a going-forward basis, just based on really characteristics of the way solar is coming online in North Carolina, that increasingly, in the future, there are going to be fewer -- likely to be -- likely to be fewer solar installations added to the grid that are going to be much larger. Each one is going to be much larger. There are going to be fewer of them, and there is gonna be less geographic diversity. And so, well, fewer projects, yeah, each are larger scale. There are not gonna be a lot of 1,000 1 megawatt projects scattered all over the place.

So would you want to comment on that observation by Mr. Wintermantel, and how does that affect your critique on that point?

A. Yes. Thank you. You're right. I'm surprised there weren't questions on it. Exactly. The reason for my hemming and hawing, you saying there won't be as much diversity is a couple of things. One is, yeah, the -- when they looked at the fleet of solar that they benchmarked against, and had a nice map, and it looked like -- I can't remember whether it was 16 locations -- some large number of locations. Well, when you went down and looked at that, it turns out that one location in DEC and one location in DEP accounted for, like, a quarter of the solar. So the -- there -- it wasn't like all of the solar was spread out evenly across that whole map. And then I think it's -- I can't remember, but it's some pretty high -- perhaps it's 80 percent is in only four of the locations. Four locations. So the amount of diversity that was in the study is actually much less than what you kind of first think when you look at this map, and it's got a lot. So that's one point, is that the base amount does not have a lot of diversity in it. Two, you --

Q. The baseline? You are referring now to the baseline?

A. Yes. Yeah. They are saying, okay, we start with this reality, which is very good, by the way. It wasn't like they went back and said, okay, well, what if I have one solar plant and I am gonna take that linear? It wasn't that bad. But it was a point in time, and that point in time has a lot less diversity in it than it first appears. Because, like I say, a quarter of it is in one site, and then I think 80 percent is in four sites. So it's really all based on four locations.

So, as you add in more solar -- and you're right, as you get these larger plants, you know, 100 megawatt solar plant is admittedly different than 100 megawatts of rooftop solar. On the other hand, you get a potful of benefits from that utility-scale plant that, kind of, outweighs your controllability, all kinds of things. So as you go to add more, right, it's a big difference between -- as I go and build coal plants -- and so you go back in the '50s, we built coal plants that were, like, 150 megawatts a unit. And then we went through, and by the time we hit the '70s, and we are now up to a coal plant that's 1,000 megawatts for a unit. Well, that's one unit. Now you've got the problem, if that guy trips off, that's a linear scaling. That's a big problem compared to -- well, solar doesn't work that way. Once I got a 100 megawatt plant, I want to add more, I can't put it on top of the existing 100 megawatts. I'm forced to at least go next door. And clouds are a finite side and they move at a finite speed. So the next plant cannot have variability that is perfectly correlated with the existing. So you immediately start to get aggregation benefits. And then you compound it with -- so here's where I was kind of a little bit disagreeing with you on, okay, as we add more -- no. I suspect -- and I'm not an expert in siting and I have not looked at where people are proposing to site solar, but when you are talking about that kind of amount, it seems like, as people just look for locations, they are gonna have to spread them out. They won't be able to put them, you know, side by side. And even if they did, you get to that massive amount of solar, you are covering a lot of acres. So even that massive size will have a significant reduction variability, and significant aggregation benefit.

Q. Thank you. There is a lot there, but I will let it go, because all I really wanted to hear was hear you comment on the Company's response.

A. Sorry about that.

Q. That's quite all right. I think that's it. Thank you.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Beach [sic], just one question. So you indicated all the ways that the modeling is flawed, or you tried to tell us as many as you could see, and in doing so, are you able to have any opinion about the impact on the final result? In other words, how -- by how much would you say that the result -- the end result, the end cost, and then subsequently the charge as proposed is a lot off, just a little off, or are you completely unable to say? What would you --

A. It's a lot off. Going back to the question of variability, you know, Duke assumed linear scaling. Well, we know a much more reasonable assumption is -- a first approximation is to assume that, in the subhourly level, minute to minute, that the plants are independent. So they add statistically. So that says that if I have -- if I have two time -- you know, twice as many plants, I'm gonna get pretty much twice as much energy. Fair enough. I'm gonna get about 1.4 times as much variability.

So, you know, at each solar level you can look at what is really my expected increase in variability compared to the base case where they -- you know, they went out and actually measured and said, okay, we got confidence so it's not their baseline, but it's back to the amount of solar that was in the --

that the variability was calibrated against. So from that, you can look and -- so, for instance, from that you see that when -- at the very high level of penetration, they ran a sensitivity case with 75 percent variability. That's still way too high. But you look at the results and you see, wow, they came down a lot. So it says no, if you came down the amount of variability -- you came down to what is the correct amount of variability, it's going to be a lot less. It's much more difficult to say what the impact is going to be with the -- based on if you replace the LOLE FLEX metric with the same modeling and have a more reasonable reliability requirement, like what Idaho did, difficult to say -- have to do some work to come up with an estimate of what that number should be.

Q. So -- and I'm sorry, I called you Mr. Beach. Mr. Kirby.

A. That's fine.

Q. So what -- so in terms of your engagement with this matter, if you were asked -- could you even ballpark the right number, or was it a situation where you don't have the -- all the inputs and all the information you would need to be able to do that?

A. Recognizing the problem that the

Commission -- ultimately, I suppose you have got to come up with a number, and -- so something I have seen done in other places -- Bonneville Power, for instance, has, at times -- I don't know if you have got the ability to do this -- comes up with where they say, okay, we've got a technical dispute. We are gonna adopt a number, and we are gonna specifically say this number does not have any precedent, it does not -- we are not endorsing the methodology that generated the number. In that case, it can be just a compromise. As far as technically estimating it without doing the study, it's tough.

I mean, the reason that Duke went to the efforts -- I mean, a lot of modeling effort, and an awful lot of it is very good. It just -- it misses a couple of things. The tool, the methodology, the comparative methodology is all sound. Just the LOLE FLEX and the scaling, you know, missed that. So it needs to -- perhaps the best solution is to just say go back and do it again fixing those problems.

Q. But you -- Mr. Kirby, you are not able, or you didn't come up -- you don't have any idea of a number that's closer, or a good grounds -- a good basis for coming up with one of those numbers?

A. You're posing an interesting technical challenge, and it's tough to resist. You know, just from thinking about how would you -- here's a puzzle, how would you solve the puzzle? So that's what is making me hesitant.

Q. That's the question before us. We've got a puzzle. How do we solve it?

A. Absolutely. So that analysis modeling is fun. So yes, that's why you want to do it. It seems to me that you could take results that are already there and correct for the amount of variability, basically -- oh, boy. So what I'm going after is the idea that you could say, well, the amount of variability that's assumed in the plus-1,500 case, say the real high penetration. Well, really, that would have been the amount of variability that was in four cases back. So you would then say -- it doesn't get to the LOLE FLEX, unfortunately, which is our fundamental problem.

Just setting that piece aside, just trying to fix the variability problem, yeah, you could come out and say, all right, I will look at the cost of the higher amounts of reserves for however many cases you had to go back to match the correct amount of variability, apply it to that higher amount of -- and that would start to get you closer, except for the fact that the LOLE FLEX still has a -- probably screws you up, yeah.

Q. All right. And then with regard to the redispatch charge, there your recommendation was that we go back and have Dominion recalculate to consider the benefits.

Did you have anything, in your understanding, or in your head, that might inform what that number would be? In other words, did you do any recalculation or have any basis to do such?

A. No. No. No.

Q. Do you have any idea in which direction their number is wrong? And the same question, is it a lot off, is it a little off? They agreed to 78.

A. Right. And I certainly appreciate they are looking at the technical questions that were raised, and discussing those, and then coming to an understanding. That was very commendable. I would have an extremely difficult time estimating, you know, the value of the added benefits. I'm sorry.

Q. Your recommendation about recalculating, did it apply to the $0.78, or was that on the $1.78?

A. No. That applies to the $0.78. I fully appreciate -- as you recall, in the initial testimony there was all kinds of concerns, and they addressed all of them, which was very nice.

Q. But you would still say we need to know what it would be if the benefits were taken into account?

A. Yes. Though I would also say, just in my personal view, that the concern with Duke is a much higher concern.

Q. Okay. All right. Thank you.

EXAMINATION BY CHAIR MITCHELL:

Q. Mr. Kirby, I have just a few questions for you. You provided testimony regarding the benefits of interconnected operations?

A. Yes.

Q. It's in your prefiled, and you have spoken about it some today.

Can you -- just so I'm clear, can you give me your opinion of the benefits that flowed to the Duke utilities as a result of their being a part of VACAR and being part of the Eastern Interconnection?

A. Oh.

Q. With respect to the matter at hand, the issue of reserves.

A. Right. So VACAR -- I can't give you a number, but the benefits of being part of VACAR are very easy to calculate. They are very straightforward.

Q. And, I mean, just kind of keep it conceptual.

A. I am going to, right. So -- and the contingency reserves are kind of the perfect example. Just it turns out, for contingency reserves, you have got to go and join VACAR. The Eastern Interconnection, you don't join it, you are part of it. So you are already a member.

So the example, VACAR, what VACAR does for you is -- what you would have to do if you were not a member of a contingency reserve-sharing group, you have an obligation to have -- whatever the largest generator you've got, maybe it's a 1,000-megawatt nuke, you have got to have reserves available continuously whenever that nuke is on that will compensate if it suddenly fails. So what you have to have -- I believe the requirements here would be 50 percent spin and 50 percent non, which would say, all right, if your nuke is sitting there and producing 1,000 megawatts, you have to have 500 megawatts of other generation that is online and unloaded. You probably need it spread over a number of units, but you have got to have -- you have got to have another 1,000 megawatts of generation that is only operating at 500 so it's ready to immediately respond if the nuke trips. And then you have got to have another 500 megawatts, the other half, in stuff that can start within 10 minutes. So that's what you've got to have.

You go and join VACAR -- and I can't remember right now how many other members there are in VACAR, and it gets split up in the size, so relatively the size -- if -- say DC is 10 percent of VACAR, suddenly they go from having to have 1,000 megawatts to only having to have 100, because we are now saying we don't care -- you know, even though -- even though everybody may have their own 1,000-megawatt nuke, because we are interconnected, we don't expect those -- all of them to fail all at the same time. So we are able to have a reserve-sharing group, and we share our reserves, and every one of us gets to carry only a tenth of the reserves.

Now, we do have to respond any time any one of those nukes fails. So you are gonna respond more often, but it's an incredible savings. But to do it with the contingency reserves, you join that contingency reserve-sharing group. Well, same thing happens, but kind of a more fundamental level, with this minute-to-minute variability, and it actually also applies too on the contingency reserves.

So I said, if you are not a member of the -- so you're -- you've -- you got a 1,000-megawatt nuke, and you are not a member of the reserve-sharing group, you have got to have 1,000 megawatts of reserves. And the rules are that you have got to have half of that in spinning reserve that's online and ready to go, but it's actually allowed 15 minutes to fully respond. And the fast start stuff, you've got -- by the rules, if you lose your nuke, you are given 15 minutes to restore your balance, okay. That benefit is what you got from being a part of the Eastern Interconnection. You are not having to pay anybody. It's whether -- so whether you're in VACAR or not, because you are in the Eastern Interconnection, the rules are -- and we lived with the rules long enough; we know that these are perfectly good -- that as long as you're rebalanced within 15 minutes, that you deployed all your reserves and rebalanced in 15 minutes, you're good, you met the requirements.

If you were a physical island and were not connected, if you lost a 1,000 megawatt nuke, you've got cycles to seconds to replace that energy. You are not making it. And having a reserve and say, well, I've got this -- I've got this other contingency. I met my NERC standards. I've got an online spinning reserve. It can fully ramp up in 10 minutes. Sorry, that's not good enough. Your system was black 9 hours -- or 9 minutes and 59 seconds ago.

The fact that the interconnection is there, it provides this tremendous flywheel that you are working with that is enabling -- and it works for everybody else as well. It's not like you are leaning on anybody. This is a benefit we all get. You have lower balancing requirements.

Q. Thank you. That's very helpful.

CHAIR MITCHELL: Questions on Commission's questions?

MR. BREITSCHWERDT: Just a few.

RECROSS EXAMINATION BY MR. BREITSCHWERDT:

Q. So, Mr. Kirby, in response to questions from Commissioner Clodfelter, you were speaking about the Idaho study and the metric, and the fact that it measured deviations, and you essentially, if I've got your testimony written down correctly, said that the metric allowed the Idaho system to be out of balance

for 90 hours during the year; is that --
A. I believe that's right. I would have to go and see what I wrote down.
Q. I'm not quizzing you on whether 90 is right. I think that's what you said.
A. Yes.
Q. We will agree that is correct. But that's in evaluating being out of balance or deviations when you are evaluating, generally, compliance with the NERC standards; is that fair? When you say it's out of balance, you are a deviation from the compliance requirements of the NERC standards; is that --
A. No. No. No. That was what -- so the Idaho study, as you correctly point out, did not take the NERC balancing standards and try to model them directly. Modeling them perfectly is very difficult or impossible. So they said we will have -- we will have a metric that says we -- you know, we're going to require five-minute balancing 99 percent of the time.
Q. Right.
A. And so that's the metric the study is trying to meet. And, you know, implicitly, that metric is a surrogate for the NERC balancing requirement.
Q. And the assumption is you are in balance, not

a deviation; out of balance, that's a deviation, correct?

A. Yeah.

Q. And it gives you the benefit of 90 hours a year to be out of balance and that being a deviation?

A. Yes. It basically says that if during a five-minute interval, say, solar took a big dip and then came back, and it was only just one five-minute interval, as long as it didn't happen too many times, you were fine.

Q. And it was based on actual system operations, so it's looking backwards and saying, did the system operator stay within balance; is that correct? The five-minute data that it was modeling was based on actual system operations, correct?

A. No.

Q. The five-minute deviation data that they were evaluating was based on actual system operations?

A. The load data and the solar data, yes.

Q. Right. So there was no perfect foresight that the system operator would have had in their model; it was based on actual system operations, so there was not an assumption, as there is in the Astrape model, that the system operator has perfect foresight five minutes ahead and can ramp the generation to meet load; would you agree with that?

A. I think so. I'm not -- the question is a little --

Q. Well, I think we've just been talking past each other. I mean, I think Mr. Wintermantel, on page -- do you have his testimony, by chance?

A. (No response.)

Q. That's all right. So on page 17 of his testimony the question is raised of is LOLE FLEX generally utilized industry metric or standard reliability, and he says no. We all agreed on that. But he does say that LOLE FLEX, as used in SERVM, is a measure of system reliability to satisfy net load obligations, assuming net load is known five minutes before it materializes.

Would you accept that that's his testimony, subject to check?

A. Yes.

Q. And that's a different methodological approach used in the Astrape study and used under the SERVM modeling approach than what you were characterizing as the Idaho approach where the system is out of balance and they are allowed a greater amount of flexibility of 90 hours a year?

MS. BOWEN: I'm sorry, can you -- is this directly responsive to one of the questions from the Commissioners?

MR. BREITSCHWERDT: Commissioner Clodfelter was asking about the Idaho metric and why it was more appropriate or less conservative than the LOLE FLEX metric that the Astrape study used. I mean, this is pretty fundamental to the Commission's question here, and I just wanted to make sure we are in alignment here.

Q. Would you agree with that?

A. The reason I'm having so much trouble with the question is because the Idaho study not only includes the movement of the solar -- and the Astrape study says, okay, we will put in the movement of the solar and the load, and then we will assume the operator has got perfect foreknowledge of that.

Q. Correct.

A. The Idaho study says, not only will we put in the actual movement of the solar, and the actual movement of the load, and the actual movement of the wind, but we will not assume perfect foreknowledge. We will throw in uncertainty. We will throw in the uncertainty of the worst five-minute deviation from the hour-ahead forecast.

Q. That's right.

A. So it says that what -- when Idaho imposed, you know, the 99 percent, they were -- they were looking at an even tougher problem, because it includes uncertainty as well as variability.

Q. And so because that uncertainty is included, they are allowing additional -- they are being less conservative in the metric, they are allowing additional flexibility in the metric, so whereas SERVM assumes perfect foresight and is modeling to the 0.1 flex, which is reflective of system operations and operating reserves in 2015 prior to solar being added, what Idaho does is they don't assume that perfect foresight, and they are reviewing the deviations that actually occurred; is that correct? Do you agree with that? Potentially, we were on the same page there for a brief moment. Perhaps not.

A. We can't have that.

Q. Right. I think that's where we have been today.

A. Okay. My -- the problem having -- getting my head around it to make sure I'm understanding your question is, the way I'm hearing it, it sounds like you're arguing against yourself, which I suspect you're not. So that makes me think I don't understand the question, because you showed me an example trying to say that the Idaho study comes up with the same amount of reserves as the Astrape study.

Q. Correct.

A. And my response to that is yes, and the Idaho study assumes uncertainty as well as variability. So if you were to add uncertainty on top of that to the Astrape study, it would jump the reserve requirements up higher and they would no longer agree.

Q. Would you agree that one is an hourly production cost modeling where the variabilities assumed are quantified outside of the model and it's fully integrated in the Astrape model on a five-minute time step?

A. Yes. But I would add to that that the subhourly variability is fully included for every hour in the Idaho study, they just -- they don't happen to do it inside the production cost model, but it is fully accounted for every hour.

Q. Right. I think we have gotten to the point that we agree that they are different methodologies; you agree with that?

A. I actually don't think the methodologies are very different, with the exception of -- with the exception of the choice of that metric, the LOLE FLEX versus the 99, and then also how the solar was scaled. There is a difference there.

Q. And I apologize. Your counsel has been very patient here, and I just have one more question related to a question that Commissioner Brown-Bland asked, and she asked about linear scaling, and you went through your perspective that -- and I think this is what you were articulating, was that linear scaling was necessary and appropriate, especially at the more significant penetrations, and you pointed to the highest penetration of the study where the Astrape modeler added 75 percent versus 100 percent of the scaling. So it didn't linearly scale out in that fourth iteration of the study.

Do you agree with that? Do you recall that discussion with Commissioner Brown-Bland?

A. I recall a discussion. I do not recall my saying that I thought the linear scaling was appropriate. It's inappropriate.

Q. That's right, but my point is that -- I'm sorry, please finish.

A. And the -- my understanding of the Astrape study is that the 75 percent was done as a sensitivity, but those results were basically not used. So the -- all the used results were a linear scaling, and that's -- to me, that's just wrong.

Q. Well, I appreciate that, and I guess my point is, would you agree that the actual level of solar penetration and the charge that's being established in this proceeding is not based on those future scenarios where the linear scaling should or shouldn't be included, but based on the existing plus transition that's based on the actual operation of the solar fleet today, and it's not this third or fourth tranche iteration that's being added in the future? So in a future proceeding we could debate about the level of linear scaling further out in the future and the amount of appropriate solar diversity, but for the purposes of the charge that the Companies have proposed, it's based on the existing plus transition and these linear scaling questions are prospective and may be issues with modeling out in the future, but not for the actual charge that's been proposed?

A. No. And the reason I disagree with you is, the size of the fleet that was actually measured -- so they took one year of historic data, and that fleet -- and I have it in my testimony. There is a table. And that fleet was significantly smaller than for the next two iterations, which are part of this study. And so there is a significant overstatement of variability for even the solar that exists now. So, to that point, you could go and look at what the variability is now and see if that matches what the study is assuming.

Q. And you, perhaps -- you could accept, subject to check, that the existing plus transition vintage of solar, the 840 megawatts in Duke Energy Carolinas and the 2,950 megawatts for Progress, are all legacy PURPA projects that are of the same size and of the same type that were on the system in 2016/2017.

So the conversation you had with Commissioner Clodfelter about the new larger solar plants is based on the evolved implementation framework of --

MS. BOWEN: Mr. Breitschwerdt, I'm sorry. I feel like you're responding to different questions by different Commissioners, and it's --

MR. BREITSCHWERDT: That's fair enough.

MS. BOWEN: Okay. Thanks.

MR. BREITSCHWERDT: I think I can withdraw the question and stop there.

THE WITNESS: Darn, I just found the number.

MR. LEVITAS: Madam Chair, one question?

RECROSS EXAMINATION BY MR. LEVITAS:

Q. Following on Commissioner Brown-Bland's inquiry, Mr. Kirby, would you be willing to work with Astrape and the Commission to try to develop an alternative charge that responds to your concerns and that you believe would be a more accurate and valid charge to be used for this purpose?

A. Certainly.

Q. Do you have any idea how long that might take?

A. Oh, boy. Depending -- that would be completely up to Duke. I don't see it as a very long -- you know, it's not a multiple-years effort, it's something significantly shorter than that.

Q. Thank you.

RECROSS EXAMINATION BY MR. DODGE:

Q. Mr. Kirby, I'm gonna make one more attempt too with this modeling question. I think the surrogate question that Commissioner Clodfelter asked about the Idaho study, and he thought it was maybe a more comparable approach to meeting those NERC standards. So if you have the Idaho solar study --

A. I do.

Q. On page 20, I just want to make sure I understand the answer you were giving about what is known with regard to what variability or uncertainty is allowed. So looking at the top of page 20, it's describing the model here.

Does the production cost model that was used in this study allow any mismatch between generation and load in the time step being evaluated, or is it assumed that those are in balance?

A. (Witness peruses document.)

I'm trying to remember. I think -- the study does not assume that they are in balance. In fact, that's a fundamental -- you keep adding similar -- you keep adding reserves until you achieve the same level of balance. In this case, 99 percent.

Q. And that's for the solar portion -- the change in the solar, but the load imbalance for the system, as a whole, is stipulated to be imbalanced?

A. No. You are not -- you never -- you don't really care what the solar is doing on its own. It's only once you have netted the solar with the wind and the load. So it's only the aggregate of load, wind, and solar that you are checking against. That's what the conviction at generation fleet is being dispatched against. And then the model looks at that and says, you know, is it able to meet that match. And it's requiring it to be able to meet that match. Or it's able to -- the generation is able to match load, you know, so it allows a 1 percent -- 1 percent of the time it allows a deviation.

Q. Okay. Thank you.

MS. BOWEN: I think I have just one question, if that's okay.

CHAIR MITCHELL: Okay. Well, one question.

REDIRECT EXAMINATION BY MS. BOWEN:

Q. Very briefly, but Commissioner Brown-Bland asked you questions about, you know, what can the Commission do with this issue and with the problems that you raised.

I just -- my one question is, what is the practical effect of getting the reliability metric wrong? So if the LOLE FLEX metric is the wrong metric to be using, what is the practical impact for the Commission to be aware of of getting that metric wrong?

A. The practical impact is that the calculation of the reserve amounts is then -- is wrong, or you don't know that it's right, and then, consequently, you don't know if the cost is right.

Q. Thank you.

CHAIR MITCHELL: I will -- if there are no further questions for the witness, I will entertain motions.

MR. BREITSCHWERDT: Sure. I move State's -- Duke Energy State Cross Exhibits 1, 2, and 3 into the record, please.

MS. BOWEN: No objection.

CHAIR MITCHELL: Hearing no objection, motion allowed.

(DEC/DEP Kirby Cross Examination Exhibit Numbers 1 through 3 were admitted into evidence.)

MS. BOWEN: I would like to move Mr. Kirby's testimony into the record in regard to his prefiled testimony and the exhibits. I believe that we have. I can make another motion if I need to.

CHAIR MITCHELL: So your motion pertains to?

MS. BOWEN: Well, his testimony is on the record, so I think we are good.

CHAIR MITCHELL: Okay.

MS. BOWEN: If I may, just one more very quickly, we also have -- the parties have stipulated to Mr. Wilson's testimony, and we can file a verification of that testimony with the Commission at a later date if needed, and then we would also like to move into the record SACE's initial comments and reply comments and attachments into the record.

CHAIR MITCHELL: The motion is allowed, hearing no objection, with respect to SACE's comments.

(SACE's Initial Comments and Reply Comments and Attachments were admitted into evidence.)

CHAIR MITCHELL: Mr. Wilson's testimony?

MS. BOWEN: Do we need to file a verification with the Commission? We can, if needed.

CHAIR MITCHELL: Okay. Without

objection, your motion to move Mr. Wilson's testimony into the record shall be allowed.

MS. BOWEN: Okay. Without verification, great. Thank you.

(Whereupon, the prefiled direct testimony of James F. Wilson was copied into the record as if given orally from the stand.)

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

DIRECT TESTIMONY OF JAMES F. WILSON ON BEHALF OF SOUTHERN ALLIANCE FOR CLEAN ENERGY

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I. Introduction and Qualifications

Q: Please state your name, position and business address for the record.

A: My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, Maryland 20814.

Q: Please describe your experience and qualifications.

A: I have thirty-five years of consulting experience, primarily in the electric power and natural gas industries. Many of my assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients.

With respect to the resource adequacy issues I will address in this testimony, I have been actively involved in these issues in the PJM Interconnection, L.L.C. ("PJM") region for many years, participating in PJM stakeholder processes, performing and presenting analysis of these issues, and submitting affidavits in various regulatory proceedings. I have also been involved in these issues in various state regulatory proceedings, most recently in North Carolina.

I have submitted affidavits and presented testimony in proceedings of the FERC, state regulatory agencies, and U.S. district court. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is attached to my testimony as Wilson Exhibit A.

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

A: I am testifying on behalf of the Southern Alliance For Clean Energy.

Q: Are you sponsoring any exhibits?

A: Yes. I am sponsoring an expert report, *Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing* ("*RA and Capacity Report*" or " my *Report*"), included as Wilson Exhibit B. I am also sponsoring my curriculum vitae, which is included as Wilson Exhibit A.

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

A: The purpose of my direct testimony in this proceeding is to respond to certain aspects of the avoided capacity rate design included in the proposed Stipulation of Partial Settlement[1] filed on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Companies" or "Duke

[1] Stipulation of Partial Settlement Among Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and the Public Staff, April 18, 2019 (hereinafter "Rate Design Stipulation").

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Energy") and the Public Staff, and to provide an evaluation of the underlying resource adequacy studies.

Q: Please briefly provide background information regarding the stipulation and resource adequacy studies.

A: In their initial filings, the Companies proposed, in new Schedules PP, avoided capacity credits with modified seasonal and hourly structures.[2] The Public Staff filed initial comments recommending additional granularity as part of the avoided energy and capacity rate design.[3] In reply comments and supporting testimony, Duke Energy proposed an updated avoided energy rate design that incorporated some aspects of the Public Staff's proposal.[4] On April 18, 2019, Duke Energy and the Public Staff entered into a *Stipulation of Partial Settlement Among Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and the Public Staff* ("the Stipulation"), which included an updated avoided energy rate design and avoided capacity rate design to be included in the Companies' Schedules PP.

The seasonal weighting and other aspects of the proposed avoided capacity rates and rate design included in Duke Energy's initial proposed rates, and in the Stipulation, are based upon resource adequacy studies ("DEC 2016 RA Study", "DEP 2016 RA Study"; collectively "2016 RA Studies") that were

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[2] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits, Docket No. E-100, Sub 158 (hereinafter "Duke Energy Initial Statement and Exhibits").
[3] Initial Statement of the Public Staff, Docket No. E-100, Sub 158, pp. 46-57.
[4] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Reply Comments, Docket No. E-100, Sub 158, pp. 67-74; Direct Testimony of Glen A. Snider pp. 18-32.

prepared for DEC and DEP by Astrapé Consulting in 2016.[5] The capacity values for solar resources that are reflected in the proposed avoided capacity rates and rate design were based on a Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study ("*Solar Capacity Value Study*")[6] that employs the same model and many of the same assumptions that were used in the 2016 RA Studies.

II. REVIEW OF DUKE ENERGY'S RESOURCE ADEQUACY STUDIES AND SOLAR CAPACITY VALUE STUDY

Q: Please summarize the avoided capacity rate design proposed in the Stipulation.

A: The Stipulation proposes a 100%/0% winter/summer capacity payment weighting for DEP, and 90%/10% for DEC.[7] The Stipulation also proposes changes to the existing monthly and hourly structure. These changes are intended to reflect the recent experience with extreme cold temperatures and also higher solar penetration. Duke Energy's initial avoided capacity rate design proposal, and the rate design proposed in the Stipulation, are based on the analysis documented in the 2016 RA Studies and related Solar Capacity Value Study.

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[5] Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study, August 27, 2018 (hereinafter "*Solar Capacity Value Study*") pp. 16, 34; NCSEA's Initial Comments, Attachment 4 (filed copy of *Solar Capacity Value Study*); Duke Energy Initial Statement and Exhibits at p. 14, n. 30; *see also* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Response to SACE Data Request No. 2, Item No. 2-24, Docket No. E-100, Sub 158 (providing copy of 2016 RA studies); Initial Statement of the Public Staff Exhibits 3-4 (filed copies of 2016 RA studies).

[6] *Solar Capacity Value Study* at pp. 16, 34.

[7] Rate Design Stipulation IV.B.; *see* Duke Energy Initial Statement and Exhibits at pp. 29.

Q: Please describe your *RA and Solar Capacity Report*, included as Wilson Exhibit B.

A: The *RA and Solar Capacity Report* attached as Wilson Exhibit B documents my review and evaluation of the 2016 RA Studies and the Solar Capacity Value Study. I performed this review and evaluation in the context of analyzing Duke Energy's initial filings in this proceeding, and this same report was filed as Attachment B to SACE's Initial Comments.

Q: After reviewing the Companies' prefiled direct testimony and the proposed Stipulation, is there anything in your *RA and Solar Capacity Report* that you would change?

A: No. The avoided capacity rates and rate design included in the Stipulation are based on the same flawed analysis as the Companies' initial proposals.

Q: Please provide an overview of the primary issues you identified with the RA Studies and Solar Capacity Value Study.

A: My *Report* shows that flaws in the 2016 RA Studies and Solar Capacity Value Study resulted in inaccurate and improper avoided capacity rates. The 2016 RA Studies significantly overstate the risk of very high loads under extreme cold, primarily due to the faulty approach used to extrapolate the relationship between temperature and load to very low temperatures.[8] The relationship between temperature and load under extreme cold is much weaker than the 2016 RA Studies assume, as discussed extensively in my report filed on February 17, 2018

[8] *RA and Solar Capacity Report*. Exhibit B, pp. 5-13.

in Docket No. E-100, Sub 147 ("Wilson 2017 RM Report"),[9] and in my updated analysis this year described in my *RA and Solar Capacity Report*.[10] Winter resource adequacy risk was also overstated due to the demand response and operating reserve assumptions applicable to winter peak conditions.[11] The 2016 RA Studies assume that demand response will continue to be summer-focused, despite identifying more resource adequacy risk in winter than in summer.[12] If the Companies believe that load loss risk is mainly in the winter, they should focus attention on developing the substantial potential for winter demand response,[13] which would lead to more balanced seasonal resource adequacy risk. As shown in my *Report*, if the 2016 RA Studies were to assume equal levels of demand response in winter and summer, most of the hours with load loss would be in summer rather than winter.[14]

Both winter and summer risk were further overstated due to the economic load forecast uncertainty assumptions, which greatly overstate the risk of large and unexpected increases in peak load.[15]

My *Report* also notes that the Companies' approach (based upon the 2016 RA Studies and Solar Capacity Value Study) to estimating seasonal, monthly and hourly resource adequacy risk, seasonal capacity values of solar resources, and recommended reserve margins will be highly sensitive to various assumptions that

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[9] Wilson 2017 RM Report, Docket No. E-100, Sub 147 at pp. 3-12.
[10] *RA and Solar Capacity* Report, Exhibit B, pp. 6-11.
[11] *Id.* at pp. 19-20.
[12] *Id.* at pp. 19.
[13] *Id.* at p. 20.
[14] *Id.* at pp. 19-20.
[15] *Id.* at pp. 14-19.

can change dramatically over just a few years.[16] This suggests that the avoided capacity design, should not be overly focused on relatively few months of the year or hours of the day, because the Companies' estimates of the seasons and hours with resource adequacy risk can change over time as load shapes and the resource mix change. If the rate design is narrowly focused on certain months and hours, as conditions change over the duration of a contract the rate design may come to inaccurately reflect avoided capacity value.

Additionally, the price signals inherent in the rate design can shift capacity needs to adjacent hours or months. While it is important to strive for accurate price signals, it is also important to strive for price signals that are reasonably stable over time, and likely to remain reasonably accurate as conditions change.

III. RECOMMENDATIONS

Q: Do you have a recommendation with regard to the seasonal and hourly allocation of capacity payments proposed in the Stipulation?

A: Yes. The Stipulation asserts that "it is reasonable and appropriate for the Companies' seasonal and hourly allocations of capacity payments to be based on the loss of load risk identified in the Astrapé Solar Capacity Value Study."[17] As explained above and in my *Report*, there are flaws in the underlying RA Studies and related Solar Capacity Value Study. Accordingly, I disagree with the conclusion set out in the Stipulation, and provide the following recommendations:

[16] *Id.* at pp. 23-24.
[17] Rate Design Stipulation at IV.A.

1. I recommend that the winter/summer capacity values proposed for use in the avoided capacity cost weightings (100%/0%, 90%/10%) in the Companies' Schedules PP be rejected, and much more balanced seasonal weights developed and approved.
2. Because the rates and rate redesigns included in the Stipulation are based on the same flawed analysis that is highly sensitive to various questionable assumptions, I also recommend rejecting the proposed monthly and hourly rate structures.

Q: Do you recommend specific seasonal weightings, or monthly and hourly rate structures?

A: No. This would require use of the Companies' modeling tools to perform further analysis after correcting the flaws identified above (estimated loads under extreme cold; demand response and operating reserve assumptions; and load forecast uncertainty).

Q: What impact would the flawed seasonal capacity value weightings reflected in the Stipulation have on the value of solar resources?

A: Because solar resources tend to have higher availability during summer, the seasonal capacity value weightings proposed in the Stipulation would result in understating the capacity value of solar resources.[18]

[18] *See RA and Solar Capacity Report*, Exhibit B at p. 23.

Q: Do you have any recommendations regarding the resource adequacy and capacity value studies the Companies might rely upon for future avoided cost filings?

A: Yes. To ensure that the Companies' resource adequacy studies more accurately estimate their loss of load risk to support the Companies' seasonal and hourly allocation of capacity payment, the Companies should:

1. Study the relationship between extreme cold conditions and load, taking into account relevant factors such as likely facility closures and impact of wind speeds, to inform the assumptions to be used in future resource adequacy studies;
2. Research the drivers of sharp winter load spikes under extreme cold conditions and develop programs for shaving these rare and brief spikes.
3. Research the potential for load forecast errors due to economic and demographic forecast errors, and the extent to which these errors could lead to less capacity than planned in a delivery year.
4. Provide more detailed information about future resource adequacy and related capacity value studies, including all model reports and a more comprehensive set of sensitivity analyses.

Q: Does this complete your direct testimony?

A: Yes it does.

MS. KEMERAIT: One additional motion. Michael Wallace with EcoPlexus is here today, and we prefiled testimony consisting of 10 pages and exhibits on July 5th. That testimony relates to energy storage, and he provides technical explanation about how the output from the underlying solar-only facility can be measured, and separately from the output from the added energy storage facility. And all parties have waived the cross examination of Michael Wallace, so I would move that his prefiled supplemental testimony and exhibits be admitted into evidence.

CHAIR MITCHELL: Without objection, the prefiled testimony of Mr. Wallace will be copied into the record as if given orally from the stand. The exhibits thereto shall be identified as marked in the prefilings and received.

(Wallace Supplemental Exhibit Numbers A through C were admitted into evidence.)

(Whereupon, the prefiled supplemental testimony of Michael Wallace was copied into the record as if given orally from the stand.)

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STATE OF NORTH CAROLINA

UTILITIES COMMISSION

RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:

Petition for Approval for the Inclusion of Battery Storage in the Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities

SUPPLEMENTAL TESTIMONY

OF

MICHAEL R. WALLACE, PE, CEM, GBE

ON BEHALF OF THE

ECOPLEXUS INC.

JULY 3, 2019

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael R. Wallace. My business address is 600 Park Office Dr., Suite 285 Research Triangle Park, NC 27709.

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

A. I am the Vice President of Development in the Southeast United States for Ecoplexus Inc. ("Ecoplexus").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of Maine. I am a professional engineer licensed in North Carolina, Maine, New Hampshire, Vermont, Massachusetts, New York, Virginia, Georgia, Florida, California, and Washington. I am a Certified Energy Manager in the United States, and I am currently completing a Master of Business Administration degree from Kegan Flagler School of Business, University of North Carolina at Chapel Hill.

I have more than sixteen years' experience in progressively responsible engineering and business leadership.

As the Vice President of Development in the Southeast United States for Ecoplexus, I am responsible for leading business planning, business development, and design expertise in all aspects of utility scale solar and battery storage with a focus on projects designed for distribution and transmission interconnections ranging from 2 megawatts ("MW") to 300 MW AC in the Eastern United States. I manage a team of twelve individuals who guide renewable energy projects from concept through development and to construction. I am also responsible for strategy and business planning in the Southeast United States. I currently manage a development pipeline of approximately 3,000 MW AC. I am responsible for origination of projects with utilities, including Duke Energy, Florida Power & Light, South Carolina Electric & Gas, Dominion Energy, Southern Company, Tampa Electric Company, and Santee Cooper. Additionally, I am responsible for all aspects of development of utility-scale projects to construction, including negotiation of purchase power agreements and interconnection agreements.

My curriculum vitae is attached hereto as Exhibit A.

Q. FOR WHOM ARE YOU SUBMITTING SUPPLEMENTAL TESTIMONY FOR IN THIS PROCEEDING?

A. I am submitting supplemental testimony in this proceeding on behalf of Ecoplexus.

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

A. The purpose of my testimony is to (1) respond to the direct testimony submitted by Duke Energy Progress, LLC and Duke Energy Carolinas, LLC (collectively, "Duke") and the Public Staff that the addition of storage to solar facilities should be allowed if the Qualifying Facility ("QF") agrees to enter into a new or modified power purchase agreement ("PPA") at Duke's current avoided cost rates, and (2) to provide technical information regarding how a DC -coupled battery solution can be metered once added to an existing qualifying facility.

Q. DOES ECOPLEXUS HAVE EXPERIENCE WITH BATTERY STORAGE IN THE STATE OF NORTH CAROLINA?

A. Yes. Ecoplexus recently participated in Tranche 1 of Duke Energy's Competitive Procurement of Renewable Energy ("CPRE") program and two of its projects which include battery storage were selected and recommended for PPAs. Ecoplexus' projects will be the first third-party transmission-interconnected battery storage projects in North Carolina.

Q. HAVE YOU HAD AN OPPORTUNITY TO REVIEW DUKE WITNESS GLEN A. SNIDER'S TESTIMONY ABOUT ENERGY STORAGE AND DUKE POSSIBLY ALLOWING A QF TO MODIFY AN EXISTING FACILITY TO ADD BATTERY STORAGE IF THE QF AGREES TO ENTER INTO A NEW MODIFIED PPA AT DUKE'S CURRENT AVOIDED COST RATES?

A. Yes. I have read and analyzed Duke Witness Glen A. Snider's direct testimony regarding allowing the addition of energy storage to an existing facility if a QF agrees to enter a new or modified PPA. I agree this is a reasonable position for the portion of the facility that adds battery storage and support it.

Q. HAVE YOU HAD AN OPPORTUNITY TO REVIEW THE INITIAL STATEMENT OF THE PUBLIC STAFF SUBMITTED ON FEBRUARY 12, 2019?

A. Yes, I have reviewed the Public Staff's testimony, in particular pages 73 – 84 that address the addition of battery storage.

Q. DOES ECOPLEXUS AGREE WITH THE APPROACH SUGGESTED ON PAGE 75 OF THE PUBLIC STAFF'S TESTIMONY TO SEPARATELY METER ANY ADDITIONAL ENERGY OUTPUT FROM THE ORIGINAL FACILITY AND COMPENSATE THAT ADDITIONAL OUTPUT AT THE THEN-CURRENT COMMISSION-APPROVED AVOIDED COST RATES WITHOUT REQUIRING THE EXISTING FACILITY TO FORFEIT PAYMENTS UNDER THE TERMS OF ITS EXISTING PPA?

A. Yes, Ecoplexus believes that this approach is an appropriate and feasible means of balancing the need to incentivize new technologies with establishing appropriate rates that reflect their value. There are multiple methods to track, record, and transfer the energy stored and released from a battery storage system. One method includes transferring that data directly from the Energy Management System provided by the battery storage provider through network communications onsite. Another method is to add a DC meter to the storage output so that energy output could be compensated at the current avoided cost rates and separated from the pre-existing PPA.

Q. CAN YOU ELABORATE ON HOW ENERGY STORED AND RELEASED FROM THE BATTERY STORAGE SYSTEM CAN BE SHARED WITH UTILITIES OR OTHERS?

A. Yes. The battery management system ("BMS") collects information such as the energy and power of the storage system in real-time and delivers it to the Energy Storage System ("ESS"), which processes and analyzes that data. Battery storage BMS and ESS integrators provide a cloud-based system for monitoring, sharing and displaying data. If necessary, a utility may request information from the BMS and ESS provider to connect to the utility-owned SCADA system in parallel to the cloud-based software.

BMS and ESS providers operate under MESA-ESS specifications. The purpose of MESA-ESS specification is to support the use of communication standards, promote interoperability, and minimize the amount of non-recurring engineering that is required to integrate ESS into utility operations using DNP3.

The MESA-ESS specification defines the communication requirements for utility-scale ESS, including ESS configuration management, ESS operational states, and a profile of the IEEE 1815 (DNP3) standard based on the information model for advanced DER functions. These advanced DER include all the functions defined in IEEE 1547:2018, California's Utility DER Electric Rule 21 Interconnection, and the European ENTSO-E DER interconnection requirements (2016), as well as additional functions of particular interest to ESS. This specification references the DNP3 Application Note AN2018-001 which is based on a DNP3 Mapping Spreadsheet, which directly maps the IEC 61850 data objects for basic and advanced DER functions to DNP3 data objects. A copy of this specification can be found in Exhibit B.

Q. CAN YOU ELABORATE ON HOW ENERGY STORED AND RELEASED FROM THE BATTERY STORAGE SYSTEM, WHICH IS DIRECT CURRENT, COULD BE METERED?

A. Each solar facility has an alternating current (AC) revenue meter at the point of interconnection owned by Duke Energy, which will remain in place. A proposed solution is to add a direct current meter for each storage block after the DC/DC converter and before the inverter. An example of a meter that would work in this application is provided by a company called Accuenergy, which manufactures power and energy metering products to distribute, control, and manage electricity, specializing in "multifunction power meters, power quality analyzers, flexible current transformers, split core CTs, network communication modules, cloud-based energy management systems and tenant billing solutions."[1]

A DC meter can communicate to other networks utilizing Modbus-RTU. The utility or the developer will be able to pull voltage, current, energy or power directly from one of these meters. In case of loss of communications for this system, all metering parameters can be recorded in 1-minute intervals for up to four months using a data recorder. Once communications are restored, data is pushed back to the network for use. An AC revenue meter is governed by the American National Standards Institute ("ANSI") C12.1. ASNI standards require an AC revenue meter which is measured in watt-hours to be 0.2% accurate. Currently there are no ANSI or IEEE standards in place for DC-meters, however many DC-metering companies like Accuenergy provide meters that can meet ANSI C12.1 accuracy specification. Accuenergy's AccuDC 240 Series DC Power and Energy meters can provide a 0.2% accuracy for voltage, current, power and energy. Please see Exhibit C where a technical specification sheet is provided with cost.

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[1] Accuenergy, https://www.accuenergy.com/about-us/.

Q. IF DC ENERGY CAN BE MEASURED WITH REVENUE GRADE ACCURACY AS YOU'VE DESCRIBED, HOW WOULD THE UTILITY USE THIS INFORMATION TO SEPARATE THE ENERGY FROM THE STORAGE SYSTEM?

A. This could be completed in different ways, and one method that should be considered is to use a ratio of DC-metered output to array-metered output. Inverters measure the current and voltage from the DC array at the point of injection to the inverter. This information is available to the site operator and can be placed on a network for viewing, analyzing and sharing. This notifies the site operator of the energy being collected from the array. At the same time energy is being transferred from the array, it could also be transferred from the storage system which is metered and shared for analyzing. A simple ratio can be calculated and used at the utilities AC meter to decipher energy from the array as opposed to energy from the storage system to ensure the proper rate is assigned. DC metered data can consider loss factors such as losses through the inverter and transformer and system line losses from the point of DC metering to the point of AC revenue metering.

Q. FROM YOUR TESTIMONY YOU'VE STATED STORAGE CAN BE METERED AND MEASURED TECHNICALLY, WHAT OTHER ISSUES SHOULD THE COMMISSION CONSIDER AND WHAT PATH FORWARD WOULD YOU RECOMMEND FOR THE INCLUSION OF BATTERY STORAGE TO EXISTING FACILITIES?

A. Storage can be measured and metered with accuracy as discussed collaboratively with the industry and utilities. There are two outstanding items which should be addressed in the coming months.

a.) A metering & communications standard should be discussed and considered. There is evidence to support these conversations are ongoing with other large utilities and organizations and further discussion can be had with NDAs in place.

b.) Commercial PPA terms should be discussed and considered collaboratively with the industry and utilities. There are commercial terms which can solve many of the storage questions which need to be addressed.

I would propose the following milestone schedule;

i.) Utilities make the commission and industry aware of their concerns both technically and commercially. (30 days)

ii.) The industry proposes solutions in a collaborative good faith effort to address the utilities concerns. (60 days)

iii.) The utility and the industry draft commercial terms and technical standards to be submitted to the public staff for review. (120 days)

iv.) A formal proposal is submitted to the Commission for review. (150 days)

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

MS. KEMERAIT: Mr. Wallace -- I know we are five minutes beyond 2:00, but he wanted me to make it clear to the Commission that he is here today in case the Commissioners have any questions of him. Thank you.

CHAIR MITCHELL: Questions by the Commission for Mr. Wallace? There are no questions. Thank you.

MS. KEMERAIT: Thank you.

CHAIR MITCHELL: Okay. We have come to the end of the day today. As a reminder, we will be back tomorrow at 11:00. Thank you. We are adjourned.

(The hearing was adjourned at 2:06 p.m. and set to reconvene at 11:00 a.m. on Thursday, July 18, 2019.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appears in the foregoing hearing were duly sworn; that the testimony of said witnesses was taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to this; and further, that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 24th day of July, 2019.

Joann Bunze

JOANN BUNZE, RPR

Notary Public #200707300112