PLACE: Dobbs Building
Raleigh, North Carolina

DATE: Monday, July 15, 2019

DOCKET NO.: E-100, Sub 158

TIME IN SESSION: 1:30 P.M. TO 5:30 P.M.

BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Generic Electric

Biennial Determination of Avoided Cost

Rates for Electric Utility Purchases

from Qualifying Facilities - 2018

Volume 2

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TABLE OF CONTENTS

EXAMINATIONS

EXHIBITS

P R O C E E D I N G S

CHAIR MITCHELL: Good afternoon. Let's come to order and go on the record. I'm Chair Charlotte A. Mitchell. With me this afternoon are Commissioners ToNola D. Brown-Bland, Lyons Gray, and Daniel G. Clodfelter.

I now call for hearing Docket Number E-100, Sub 158, In the Matter of Biennial Determination of Avoided Cost Rates for Electric Public Utility Purchases from Qualifying Facilities 2018. These are the 2018 biennial proceedings held by this Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 and applicable Federal Energy Regulatory Commission regulations pertaining to this Commission's responsibilities for determining each electric utility's avoided cost with respect to rates for purchases of power from qualifying cogenerators and small power producers.

These proceedings are also being held pursuant to General Statute 62-156, which requires this Commission to determine the rate to be paid by electric utilities for power purchase from small power producers as defined in the general statutes.

On June 26, 2018, the Commission issued its

Order Establishing the Biennial Proceeding, Requiring Data, and Scheduling Public Hearing. Pursuant to said order, Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, together I'll hereafter refer to as Duke, Virginia Electric Power Company doing business as Dominion North Carolina Power, Western Carolina University and Appalachian State University doing business as New River Power and Light Company, were made parties to these proceedings. I'll collectively refer to these parties as the Utilities.

The Commission has issued order -- orders allowing the following parties to intervene in this proceeding: The North Carolina Sustainable Energy Association, the North Carolina Clean Energy Business Alliance, Carolina Utility Customers Association, Inc., Ecoplexus, Inc., Southern Alliance for Clean Energy, North Carolina Small Hydro Group, Cube Yadkin Generation, LLC, and NC WARN, Inc.

On November 1st, 2018, the Utilities filed comments, data, and proposed rates as required by the Commission's June 26, 2018 Order. As a part of its filing, Duke noted certain rate design issues that have not previously been presented to this Commission and stated it believes that the public interest would be served by the Commission holding an evidentiary hearing and receiving testimony on those issues. Duke, therefore, requested that the Commission issue a procedural order allowing for the prefiling of testimony by interested parties and setting a date for an evidentiary hearing to receive expert testimony on those issues.

On January 25th, 2019, the Commission issued an Order on Procedural Schedule and Requiring Report. That Order, among other things, required Duke to file a report identifying all substantive issues that are anticipated to come before the Commission for determination in this proceeding, including: (1) those issues where agreement exists or can reasonably expected to be reached; (2) those issues that are in controversy, but do not merit consideration at an evidentiary hearing; and (3) those issues that are in controversy and merit consideration at an evidentiary hearing.

On April 10, 2019, Duke filed the report required by the Commission's January 25, 2019 Order. Duke's report demonstrates that there is agreement among those parties that expressed an opinion that an evidentiary hearing is not warranted as to certain issues, that although excluded from consideration at this hearing, will be considered through the parties' comments and verified statements and addressed along with other contested issues through proposed orders and briefs filed with the Commission at the appropriate time.

On April 18th, 2019, Duke and the Public Staff jointly filed a Stipulation of Partial Settlement. On April 24th, 2019, the Commission issued an Order Scheduling Evidentiary Hearing and Establishing a Procedural Schedule. The hearing scheduled for this time and this date is solely for the purpose of receiving expert witness testimony related to those specific issues listed in the April 24th order. In response to this order, Duke, Dominion North Carolina, NCSEA, SACE, and the Public Staff have filed the direct and rebuttal testimony of their respective witnesses, as reflected in the filings in this docket.

On June 14th, 2019, the Commission -- the Commission issued an Order Requiring Supplemental Testimony and Allowing Responsive Testimony. In response to this Order, Duke, Dominion Energy North Carolina, NCSEA, Ecoplexus, and the Public Staff filed the supplemental responsive and supplemental rebuttal testimony of their respective witnesses, as reflected in the filings in this docket.

Finally, I will note that there are other motions, filings, and matters not specifically mentioned that are of record in this docket.

Pursuant to the North Carolina General Statute 138A-15(e), I remind members of the Commission of their duty to avoid conflicts of interest, and inquire at this time as to whether any Commissioner has a known conflict of interest with respect to any matters coming before us today in this proceeding?

(No response.)

CHAIR MITCHELL: Please let the record reflect that no such conflicts were identified, and I now call upon counsel for the parties to announce their appearances for the record, beginning with the Utilities.

MS. FENTRESS: Good afternoon, Madam Chair, Commissioners. Kendrick Fentress appearing on behalf of Duke Energy Progress and Duke Energy Carolinas.

MR. BREITSCHWERDT: Madam Chair, members of the Commission, Brett Breitschwerdt with the law firm McGuireWoods on behalf of Duke Energy Carolinas, Duke Energy Progress. With me today is Kristin Athens, also with our law firm.

MS. GRIGG: Good afternoon Chair Mitchell, members of the Commission. I am Mary Lynne Grigg from

McGuireWoods appearing on behalf of Dominion Energy North Carolina.

MR. DANTONIO: Good afternoon, Madam Chair, Commissioners. Nick Dantonio with McGuireWoods. And with us today also we have Mr. Horace Payne from the Company, Assistant General Counsel.

MR. SMITH: Madam Chair, Ben Smith on behalf of the North Carolina Sustainable Energy Association.

MS. BOWEN: Madam Chair, Lauren Bowen with the Southern Environmental Law Center, here today on behalf of Southern Alliance for Clean Energy.

MS. HUTT: Madam Chair, Commissioners, Maia Hutt from the Southern Environmental Law Center, here today on behalf of SACE, the Southern Alliance for Clean Energy.

MS. KEMERAIT: Good afternoon, Madam Chair and Commissioners. My name is Karen Kemerait, and I'm here on behalf -- I'm here -- I'm with Fox Rothschild, and I'm here on behalf of the North Carolina Clean Energy Business Alliance and also Ecoplexus, Incorporated.

MR. LEVITAS: Good afternoon, Madam Chair, members of the Commission. I'm Steve Levitas with the law firm of Kilpatrick Townsend, here on behalf of NCCEBA.

MS. ROSS: Good afternoon, Madam Chair and Commissioners. I'm Deborah Ross with the law firm of Fox Rothschild, and I'm here for the NC Small Hydro Group.

MR. SNOWDEN: Good afternoon, Madam Chair, Commissioners. I'm Ben Snowden with the law firm of Kilpatrick Townsend, here on behalf of Cube Yadkin Generation.

MS. HARROD: Madam Chair and Commissioners, Jennifer Harrod here on behalf of the Office of the Attorney General, representing the Using and Consuming Public as well as the State and its Citizens in this Matter Affecting the Public Interest.

MR. QUINN: Madam Chair, Commissioners, good afternoon. My name is Matthew Quinn. I'm here with the law firm of Lewis & Roberts. I represent NC WARN. I'm also here with attorney Kristen Wills who likewise represents NC WARN.

MR. PAGE: Robert Page, Carolina Utility Customers Association. Good afternoon.

MR. DODGE: Good afternoon, Chair Mitchell, Commissioners. I'm Tim Dodge with the Public Staff, representing the Using and Consuming Public. Appearing with me today is Lucy Edmondson, Heather Fennell, and Layla Cummings.

CHAIR MITCHELL: Thank you. Okay. Just to -- to be certain, anyone else?

(No response.)

CHAIR MITCHELL: Okay. A few preliminary matters before we begin. I'd like to first take up SACE's motion to set July 18th or 19th as a date certain for the scheduling of testimony by SACE's Witness Glick. It appears that this motion is unopposed.

MR. BREITSCHWERDT: That's correct.

CHAIR MITCHELL: And I'm prepared to grant this motion. Is there any objection?

(No response.)

CHAIR MITCHELL: Okay. Without objection, that motion is granted.

All right. Second, SACE's motion to excuse Witness Wilson from personally appearing at this hearing and to allow the prefiled direct testimony of Witness Wilson to be received into evidence as if given orally from the stand, and the two exhibits attached to his testimony to be identified as premarked and likewise exhibited -- I mean, admitted into the record. It appears that this motion is unopposed.

MR. BREITSCHWERDT: That's correct.

CHAIR MITCHELL: Okay. And I'm prepared to grant this motion unless there is objection.

MS. FENTRESS: No objection.

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

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

(Whereupon, Wilson Exhibits A and B were identified as premarked and admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100 SUB 158

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities -- 2018	)	**JAMES F. WILSON ON BEHALF OF SOUTHERN ALLIANCE FOR CLEAN ENERGY**
	)	

Table of Contents

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").

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

[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.

[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

[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:

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[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.

CHAIR MITCHELL: Okay. The third motion we will deal with today is Ecoplexus' motion that the supplemental testimony of Witness Michael Wallace be accepted as timely filed. The Commission has not received any filings indicating opposition to the granting of this motion. I'm inclined to allow it unless there is objection.

MR. BREITSCHWERDT: No objection.

MS. FENTRESS: No objection.

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

Okay. Fourth, SACE has filed a motion requesting a date certain for Witness Kirby to appear in this proceeding. It's my understanding that this motion may now be rendered moot, but I'd like to hear from you before ruling.

MS. BOWEN: Yes, Madam Chair. Thank you very much. That is correct. Mr. Kirby is here, and he is -- he is able to testify before the Commission at the Commission's convenience.

CHAIR MITCHELL: Okay. Thank you. Okay. Fifth, and finally, there's a pending motion by NCSEA that Witness Harkrader be excused from attending this hearing or, in the alternative, that the record be held open until such time as the witness can be made available for cross examination. It's my understanding that this motion is opposed. Is this still the case?

MR. BREITSCHWERDT: That's correct, Chair Mitchell --

CHAIR MITCHELL: Okay.

MR. BREITSCHWERDT: -- and be glad to let Mr. Smith speak to his motion before --

CHAIR MITCHELL: Let -- let me hear from NCSEA first, and then I'll give you --

MR. BREITSCHWERDT: Sure.

CHAIR MITCHELL: -- an opportunity to -- to be heard.

MR. SMITH: Sure. Madam Chair, again, Ben Smith for NCSEA. And we filed the motion because one of our witnesses, Carson Harkrader, who was actually a witness in the Sub 148 avoided cost proceeding, she had a mix-up of the dates of when she would be out of the state, and it had turned out after we completed the drafting and -- and filing of her testimony that she found out that -- that she -- it was made clear to her that she was not going to be here this week. And so we had already filed the testimony at that point, and so rather than try to have a continuance or otherwise request some other form of relief, we thought the best way to handle this was to request her be excused, or in the alternative, should you or anyone else want to cross her, that she would be made available at a time convenient for the Commission. She's available all of next week. And I -- and on to that point, no -- no party has requested cross examination of her, so that -- that goes to the point of maybe excusal.

CHAIR MITCHELL: Thank you, Mr. Smith. Mr. Breitschwerdt?

MR. BREITSCHWERDT: Thank you, Chair Mitchell. I think I'd take issue with no party has requested cross examination of Witness Harkrader. I think we have both attempted to respond to the testimony that she filed, and I spoke with Mr. Smith when he raised this issue in the middle of last week, and Duke Energy does oppose NCSEA's request to have her testimony either be entered in the record or to extend the hearing date past the five days the Commission has already scheduled.

We thought a reasonable approach, based on the circumstances, would be to allow the testimony which is -- seems to be largely policy oriented, not specifically focused on the discrete issues that the Commission has presented for hearing, to be accepted as a consumer statement of position. I think I'd just note that Duke has worked in good faith with SACE, NCSEA, numerous other parties to accommodate scheduling within the five days the Commission has scheduled for hearing.

This -- the dates for the schedule have not changed since the Commission issued its scheduling order probably two months ago, and the time frame for the hearing, the Commission emphasized in the scheduling order, which I'd like to refresh the Commission's recollection of, was very express to say there is very little time for the Commission to extend the time for hearing or to delay it. So, you know, I think we've tried to work in good faith, but our position is that it should neither be accepted into the record without cross examination or the time for extended.

Responding to NCSEA's first request for relief, that it be accepted into the record without allowing Duke Energy the right to cross examine, our position is that that would be unlawful under the Public Utilities Act, and if I could briefly provide you a copy. Would you pass that out, please? Yeah.

Ms. Athens will provide you a copy of 62-65, which is one of the statutes in the procedural section of the Public Utilities Act providing procedure for the Commission, which expressly states that all parties shall have the right to cross examine opposing witnesses on any matters relevant to the issues before the Commission. So as a matter of law, we don't think it's appropriate to simply allow her testimony into the record since we would request the right to cross examine her if she was available during the scheduled hearing time.

I think secondarily, because Ms. Harkrader's schedule does not permit her to be available for the hearing during the five days that it's been scheduled, it's unclear why she's out of the state, but I think our position is it's more appropriate to proceed with the hearing, conclude the hearing, and then have her testimony be accepted as a statement of position.

We really think that's appropriate for three reasons. The first is, I don't think there's any disadvantage to the Sustainable Energy Association from her testimony being accepted as a statement of position. It was largely cumulative to other testimony that has been filed by their three other witnesses, Dr. Johnson, Mr. Beach, and Mr. Norris, and so we think that's appropriate. If you note on 62-65, it recognizes the Commission exclude repetitious or cumulative evidence, and we think based on both the comments NCSEA filed in the earlier phase of this proceeding, as well as those three witnesses' testimony, it's not unreasonable for it to be accepted as a statement of position.

Also note just participating in the public hearing on this proceeding, the three witnesses for the -- or the three business members of the North Carolina Hydro Group who appeared at that public hearing made policy arguments very similar to the arguments Ms. Harkrader is making in this proceeding of the changes to the Utilities' avoided cost will adversely impact the -- the hydro industry. Her testimony largely focuses on the adverse impact to the solar industry. Ms. Harkrader candidly says up front that her company, Carolina Solar Energy, no longer is developing QFs in North Carolina, and she frankly doesn't focus on any of the technical issues the Commission has noticed for hearing. So I think that second issue supports this being appropriately a consumer statement of position.

And finally, I just would note that if Ms. Harkrader was available for cross examination, Duke would cross examine her. And the fact that she's not, I think it raises the question of whether based on the limited scope of the hearing the Commission has noticed whether she's a competent witness to testify. I noted Mr. Smith saying that she testified in the Sub 148 proceeding. I think it's significant that in that proceeding her testimony focused on the legally enforceable obligation concept which is specific to a solar developer committing to sell to the Utility, whereas here we're talking about highly technical issues related to ancillary services cost, rate design, and issues that she is not necessarily an expert witness that is 1) testifying to because her testimony is largely policy oriented, but 2) questionable whether she's presenting competent testimony on those discrete issues. If it was an open hearing on the general policies and issues related to PURPA implementation, that would be one thing, but the narrow scope of the hearing does not support her testimony being competent.

So, again, we were not going to oppose her testimony entering in the record as long as we had an opportunity to cross, but recognizing that she's not available during the five days the hearing has been scheduled, we think it's more appropriate for it to be a consumer statement of position.

CHAIR MITCHELL: Thank you, Mr. Breitschwerdt. Mr. Smith?

MR. SMITH: Yes. A couple things. First, I was unaware that there were going to be legal arguments made during this oral argument, so to the extent this statute has been presented to, I would like the chance to -- request the chance to reserve the chance to brief and -- and respond to the legal argument after doing sufficient research on the issue.

Secondly, in terms of Ms. Harkrader's competency as a witness, as I said, she has before testified on behalf of NCSEA in the form of an industry voice who understands the finances related to QF development. She says that QFs aren't currently being developed in North Carolina because of the underlying policies, some of which are highlighted within this particular proceeding.

One of the main issues that she objects to in -- particularly in Duke's filings are the -- is the solar integration charge. To have a competent expert witness on a charge that is not yet on the record or being used seems impossible for somebody from an industry perspective, given the fact that it's not yet applicable to North Carolina. I think it's Ms. Harkrader's position, as a longtime industry voice who has been previously heard in this Commission, I think she is as viable as anyone to discuss the financeability of projects, given this projected additional new charge.

And finally, I don't -- NCSEA, similar to Duke, has attempted to make this as easy as it could be for all parties, and -- and Ms. Harkrader can be available Monday morning of next week as early as possible. It was a simple mistake. I can't say that she didn't have notice. It was just a mistake in the scheduling, and so there was no intent or -- or anything but an accident on that.

So we would -- we just want to make this as easy as possible, and to the extent, you know, a consumer statement of position is what Duke is requesting this be, I guess, recognized as, we'd object because he's repeatedly referred to it being off the record, and we do think it's an important part of the record for this proceeding.

CHAIR MITCHELL: Mr. Smith, has -- has NCSEA explored the possibility of having another witness adopt Ms. Harkrader's testimony and making that witness available for cross examination?

MR. SMITH: We have, and we were unable to find somebody else who could step into her shoes.

CHAIR MITCHELL: Okay. Mr. Breitschwerdt, how much cross examination time does Duke estimate for Ms.

Harkrader?

MR. BREITSCHWERDT: Twenty to 30 minutes.

CHAIR MITCHELL: Thank you. Okay. I will take this under advisement and issue a ruling at a later time.

MR. SMITH: Thank you.

CHAIR MITCHELL: Thank you both. Okay. Any other preliminary matters that we need to address before we begin?

MR. SMITH: NCSEA just has one other preliminary matter, if you don't mind. This has to do with cross times. The filing of the cross times, which I think all the parties did, you know, in good faith -- I'm not saying anything was misrepresented -- but the -- the additional testimony came out after those estimated cross times, so I guess from NCSEA's perspective we might have a few additional questions, particularly for the Snider panel, that might run us past our estimated cross time. Again, I don't think it's more than five to 10 minutes of. That's one.

And secondly, as a matter of efficiency, NCSEA and NCCEBA have spoken and have a lot of overlapping testimony, and rather than NCSEA taking the larger burden and potentially having overlapping testimony with some of the questions, we split some of the questions that we had the same questions about on the solar integration charge in particular, so I was hoping that the Commission would allow us to -- of that estimated cross time, sort of allow us to hand some of that time over to NCCEBA.

CHAIR MITCHELL: Well, we are certainly cognizant of the fact -- of the filing dates of the testimony, and we will take your remarks into consideration. We appreciate everyone's effort to be efficient with their cross examination. So thank you, Mr. Smith.

Just a few housekeeping things before we get started. Please, everyone do your best to speak into your microphones. It helps the court reporter. It helps the Commission. It helps members in the audience who are -- who are trying to hear what we say. So please, please do your best there.

We are going to go until about 3:30 and we will take a break, give our court reporter a break and take a brief recess, and then we will come back on the record and resume at that point. And we are ready to move forward, so Duke, I believe you are prepared to go first.

MS. FENTRESS: Yes. Thank you, Chair Mitchell. If it is satisfactory to the Commission, we would like to first introduce the -- the pleadings, the comments, and the initial statement into the record, and I can go through that prior to putting the witnesses up, if that's all right with the Commission.

CHAIR MITCHELL: That would be fine. Please do so.

MS. FENTRESS: Chair Mitchell and Commissioners, we would like to introduce into the record the Joint Initial Statement and exhibits filed by Duke Energy on November 1st, 2018, the Reply Comments filed by Duke Energy on March 27th, 2019, the Rate Design Stipulation of Partial Settlement among DEC, DEP, and the Public Staff filed April 18th, 2019, and the Stipulation of Partial Settlement Regarding Solar Integration Services Charge filed May 21st, 2019.

(Whereupon, the Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs, the Reply Comments, the Stipulation of Partial Settlement Among Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and the Public Staff, and the Stipulation of Partial Settlement Regarding Solar Integrated Services

Charge were admitted into evidence.)

CHAIR MITCHELL: Without objection, those filings will be admitted into the record.

MS. FENTRESS: Thank you. And with that, we would call Mr. Snider, Mr. Wheeler, and Mr. Johnson to the stand.

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

GLEN A. SNIDER, STEVEN R. WHEELER, DAVID B. JOHNSON;

Having been duly sworn,

Testified as follows:

DIRECT EXAMINATION BY MR. BREITSCHWERDT:

Q Good afternoon, gentlemen.

MR. BREITSCHWERDT: Chair Mitchell, I'm going to introduce Mr. Snider, and then Ms. Fentress is going to introduce Mr. Wheeler and Mr. Johnson's testimony.

Q Good afternoon, Mr. Snider.

A (Snider) Good afternoon.

Q Would you please state your business address and -- your full name and business address for the record?

A Yes. My name is Glen Snider. I work for Duke Energy at 400 South Tryon, Charlotte -- or Charlotte, North Carolina.

Q Thank you. And did you cause to be prefiled on May 21st of this year 47 pages of direct testimony in question and answer form and one exhibit?

A I did.

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

A They would.

Q And do you have any corrections to that testimony to make today?

A I do not.

Q Did you also cause to be prefiled in this docket on July 3rd of this year 67 pages of rebuttal testimony in question and answer form?

A I did.

Q And do you have any changes or corrections to that rebuttal testimony?

A I do not.

Q And if I were to ask you those same questions today, would your answers be the same?

A They would.

Q And did you also cause to be prefiled on June 25th of this year 14 pages of supplemental testimony in question and answer form?

A Yes, I did.

Q And do you have any changes or corrections to that testimony?

A I do not.

Q And if I were to ask you those same questions today, would your answers be the same?

A Yes, they would.

Q And did you and Mr. Wheeler and Mr. Johnson jointly pre--- jointly file 37 pages of rebuttal supplemental testimony on July 11th, 2019?

A Yes, we did.

Q And do you have any changes or corrections to that testimony?

A I do not.

Q And if I were to ask you those same questions today, would your answers be the same?

A Yes, they would.

MR. BREITSCHWERDT: Chair Mitchell, at this time I would move Mr. Snider's prefiled direct, rebuttal, supplemental, and joint rebuttal supplemental testimonies into the -- be copied into the record as if given orally from the stand, and the Exhibit 1 to his direct testimony be marked for identification.

CHAIR MITCHELL: Without objection, that

testimony shall be admitted.

MR. BREITSCHWERDT: Thank you.

(Whereupon, the direct, rebuttal, and supplemental testimony of Glen A. Snider, and the joint supplemental rebuttal testimony of Glen A. Snider, Steven B. Wheeler, and David B. Johnson was copied into the record as if given orally from the stand.)

(Snider Exhibit 1 was identified as premarked.)

45

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of:	)	**DIRECT TESTIMONY OF**
	)	**GLEN A. SNIDER**
Biennial Determination of Avoided Cost	)	**ON BEHALF OF DUKE**
Rates for Electric Utility Purchases from	)	**ENERGY CAROLINAS, LLC**
Qualifying Facilities - 2018	)	**AND DUKE ENERGY**
	)	**PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glen A. Snider. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. WHAT IS YOUR POSITION WITH DUKE ENERGY CORPORATION?

A. I am employed by Duke Energy Corporation ("Duke Energy") as Director of Carolinas Resource Planning and Analytics.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. My educational background includes a Bachelor of Science in Mathematics and a Bachelor of Science in Economics from Illinois State University. With respect to professional experience, I have been in the utility industry for over 25 years. I started as an associate analyst with the Illinois Department of Energy and Natural Resources, responsible for assisting in the review of Illinois utilities' integrated resource plans. In 1992, I accepted a planning analyst position with Florida Power Corporation and for the past 18 years have held various management positions within the utility industry. These positions have included managing the Risk Analytics group for Progress Ventures and the Wholesale Transaction Structuring group for ArcLight Energy Marketing. Prior to my current role and immediately prior to the merger of Duke Energy and Progress Energy Corporation, I was Manager of Resource Planning for Progress Energy Carolinas.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DUKE ENERGY.

A. I am responsible for the development of the Integrated Resource Plans ("IRPs") for both Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (collectively, the "Companies" or "Duke"). In addition to the production of the IRPs, I have responsibility for overseeing the analytic functions related to resource planning for the Carolinas region. Examples of such analytic functions include unit retirement analysis, developing the analytical support for certificate of public convenience and necessity filings for new generation, and production of analysis required to support the Companies' avoided cost calculations that are used in the biennial avoided cost rate proceedings.

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

A. Yes. I most recently testified in the Commission's 2016 biennial avoided cost proceeding, Docket No. E-100, Sub 148.

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

A. In general, my testimony supports Duke's modifications to the Companies' Schedule PPs and updates to DEC's and DEP's avoided cost rates, which the Companies filed for Commission approval on November 1, 2018, as part of this current biennial proceeding to implement the Public Utility Regulatory Policies Act of 1978 ("PURPA") in North Carolina pursuant to

N.C. Gen. Stat. § 62-156(b). While not specifically addressed in my testimony, I am responsible for the Companies' methodology and inputs used to calculate the Companies' avoided capacity and energy cost rates to be paid to qualifying facilities ("QFs") as filed in the Companies' November 1, 2018, Joint Initial Statement ("Joint Initial Statement") and as extensively supported through the Companies' Reply Comments filed on March 27, 2019 ("Reply Comments"). I also support the Companies' new Integration Services Charge and modifications to the Companies' Terms and Conditions relating to proposed "material alterations" to operating QF generating facilities as presented in this proceeding.

More specifically, my testimony introduces the Companies' other witnesses and provides an overview of the Companies' positions on certain discrete issues, which the Commission's April 24, 2019 *Order Scheduling Evidentiary Hearing and Establishing Procedural Schedule* ("Order Scheduling Hearing") identified as appropriate for pre-filing of expert testimony and consideration at an evidentiary hearing in this proceeding. The Commission's *Order Scheduling Hearing* requested the parties submit testimony on "only the following list of issues:"

a. Duke's IRP Assumptions Regarding Expiring Wholesale Contracts;

b. NCSEA's Recommendation to Calculate Avoided Capacity Rate Based Upon Hypothetical 12/31/2021 In-Service Date for Standard Offer QFs;

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;

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

g. Duke's Proposed Modifications to the Standard Terms and Conditions; and

h. The Stipulation jointly filed by Duke and the Public Staff on April 18, 2019.[1]

As directed in the *Order Scheduling Hearing,* my testimony addresses each of these issues as they apply to Duke. The Companies are additionally presenting the direct testimony of the following witnesses addressing these discrete issues:

- Steven B. Wheeler, Pricing and Regulatory Solutions Director, whose testimony also addresses Duke's Proposed Solar Integration Charge "Average Cost" Rate Design and Biennial Update (issue d);
- David B. Johnson, Director, Business Development & Compliance, whose testimony also addresses Duke's Proposed

[1] *Procedural Order*, at Ordering Paragraph 3.

- Modifications to the Standard Terms and Conditions (issue g); and
- Nick Wintermantel, Principal Consultant and Partner at Astrapé Consulting, who developed the Astrapé Solar Ancillary Services Study on behalf of the Companies, to further support the Companies' testimony on Duke's Quantification of Ancillary Services Cost of Integrating QF Solar (issue c).

Q. PLEASE DISCUSS HOW YOUR TESTIMONY IS ORGANIZED.

A. My testimony is organized into the following sections:

I. Avoided Capacity
  1. Treatment of Expiring Wholesale QF PPAs
  2. QF In-Service Date

II. Rate Design Stipulation

III. Ancillary Services Costs
  1. Quantification of Ancillary Services Cost of Integrating QF Solar
  2. Response to NCSEA's and Public Staff's Proposal Related to Differing Ancillary Services Costs for Innovative QFs

IV. Proposed Modifications to the Standard Terms and Conditions

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes. Snider Direct Exhibit 1 was prepared under my supervision and direction and is further discussed in my testimony.

I. AVOIDED CAPACITY

1. Treatment of Expiring Wholesale QF PPAs

Q. PLEASE PROVIDE THE COMMISSION A GENERAL OVERVIEW OF HOW THE COMPANIES' AVOIDED CAPACITY COSTS ARE CALCULATED.

A. As introduced in the Companies' Joint Initial Statement, the Companies have again relied upon the peaker methodology in this proceeding to derive reasonable projections of DEC's and DEP's avoided capacity costs.[2] The peaker methodology credits avoided capacity value to the QF based on the utilities' cost to construct a simple cycle combustion turbine ("CT"). These costs represent the fixed capital, financing and fixed operating costs associated with the construction and operation of a CT facility. The fixed investment costs are then converted to an annual cost that includes both the recovery-of and return-on the investment in the CT, along with the annual fixed operating costs such as staffing. Once an annual value is established, it is allocated to the capacity payment hours defined in the avoided cost rate schedule and expressed in cents per kWh. Importantly, the avoided capacity calculation also takes into consideration when the utility actually has an avoidable capacity need that the QF can be credited for deferring or avoiding.

[2] DEC and DEP Joint Initial Statement, at 11-12, (filed Nov. 1, 2018) ("Joint Initial Statement").

Q. HOW ARE THE COMPANIES' IRPs UTILIZED TO DETERMINE WHEN AN AVOIDABLE CAPACITY NEED EXISTS, AND HOW IS THIS AVOIDABLE CAPACITY NEED IS THEN RECOGNIZED IN AVOIDED COST RATES?

A. The IRP is an extensive annual planning effort presenting a 15-year resource plan that identifies when the next generating unit is needed in order to maintain reliable electric service into the future. Prior to the year in which the next avoidable generation unit is needed, the utility does not have a capacity need to avoid. Thus, the calculation of the capacity portion of the avoided cost rates does not include a capacity value for years prior to the first avoidable capacity need.

Q. IS THE COMPANIES' APPROACH REASONABLE AND APPROPRIATE UNDER NORTH CAROLINA'S IMPLEMENTATION OF PURPA?

A. Yes. A central tenet of PURPA provides that customers should not be required to pay for incremental QF capacity unless the QF is actually offsetting a capacity need and associated cost that would be incurred by the utilities' customers. The Commission recently highlighted this point in the 2016 biennial avoided cost proceeding, explaining that ". . . PURPA was not intended to force a utility and its customers to pay for capacity that it otherwise does not need."[3] Session Law 2017-192 ("HB 589") also

[3] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 48-49, Docket No. E-100, Sub 148 (Oct. 11, 2018) ("2016 Sub 148 Order").

amended North Carolina's PURPA implementation framework to now expressly provide that "[a] future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] filed with the Commission has identified a projected capacity need to serve system load and the identified need can be met by the type of QF resource based upon its availability and reliability of power . . ."[4]

Q. WHAT ASSUMPTIONS DO THE COMPANIES MAKE IN THEIR IRPs REGARDING WHOLESALE PURCHASE QF CONTRACTS?

A. The Companies' IRPs include the capacity and energy from all wholesale power purchase contracts, including QF and non-QF purchases, for the duration of the contract term.

Q. WHAT ASSUMPTIONS DO THE COMPANIES MAKE IN THEIR IRPs REGARDING THE EXPIRATION OF WHOLESALE PURCHASE CONTRACTS?

A. The Companies' resource planning approach recognizes that generating facility owners are not obligated to provide capacity and energy absent a contractual obligation to do so. Therefore, the Companies' IRPs do not include energy and capacity from any third-party wholesale purchase contracts beyond the contract term.

[4] N.C. Gen. Stat. § 62-156(b)(3).

Q. HAVE ANY PARTIES RAISED CONCERNS WITH THE COMPANIES' ASSUMPTIONS REGARDING THE EXPIRATION OF WHOLESALE QF CONTRACTS IN THE COMMENT PHASE OF THIS PROCEEDING?

A. Yes. Both the NC Small Hydro Group ("Hydro Group") and North Carolina Sustainable Energy Association ("NCSEA") comment on the appropriateness of the Companies' planning assumptions regarding expiring QF PPAs.

Q. PLEASE EXPAND ON INTERVENORS' POSITIONS REGARDING THE COMPANIES' IRP ASSUMPTIONS.

A. The Hydro Group takes issue with the fact that the Companies' 2018 IRPs do not assume that hydro and biomass resources will deliver capacity after their contract term expires. Hydro Group argues that these existing QFs should be presumed to renew their PPAs at the expiration of the current contract term and that the Companies should not assume otherwise because doing so will cause these QFs to experience a decline in avoided cost rates. Hydro Group similarly argues that assuming QF retirements will create a need for additional capacity from natural gas and other non-renewable resources.[5]

In its initial comments, NCSEA took the position that there are no guarantees that existing QFs will continue to operate after their contracts have expired, and that even assuming such QFs do continue to operate, that

[5] *See generally* Hydro Reply Comments, at 4 (filed Mar. 27, 2019).

they may elect to sell their output to someone other than the Companies.[6] Therefore, NCSEA seemingly advocates that the Companies should assume existing QF contracts expire at the conclusion of their PPA term, and that upon such expiration, the Companies should identify a capacity deficit that can otherwise be fulfilled by new QFs.[7] However, NCSEA's reply comments seem to support exactly the opposite position, stating that NCSEA agrees with Hydro Group's comments and requests the Commission to recognize that "renewal and extensions of QF contracts establish the need for their capacity as of the date the original contract was executed and that the Commission subject capacity deficiencies in the IRP proceeding to additional scrutiny."[8]

Q. DID THE PUBLIC STAFF TAKE ISSUE WITH THE COMPANIES' IRP ASSUMPTIONS REGARDING EXPIRATION OF WHOLESALE QF CONTRACTS?

A. No. Neither the Public Staff's initial nor reply comments take issue with how DEC and DEP currently treat expiring QF contracts for planning purposes, and generally accept the Companies identified first year of avoidable capacity need.

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[6] *See* DEC and DEP Reply Comments, at 43-44 (filed Mar. 27, 2019) ("Reply Comments").
[7] *Id.*
[8] NCSEA Reply Comments, at 11 (filed Mar. 27, 2019).

Q. HOW DO THE COMPANIES RESPOND TO HYDRO GROUP'S AND NCSEA'S ASSERTIONS?

A. HB 589 and the Commission's *2016 Sub 148 Order*, taken together, establish that capacity is only appropriately avoided (and credit assigned under the peaker methodology) starting with the year when the utility's most recent IRP demonstrates a need for capacity that can actually be avoided. The Companies' IRPs appropriately assume that upon expiration of any third-party wholesale purchase contract (both QF and non-QF), the Companies recognize a reduction in capacity by the amount of the capacity provided in the expiring wholesale purchase contract in the year following contract expiration. As the Companies explained in their Reply Comments, Duke has long followed this approach to capacity planning in order to reliably plan to meet future capacity deficiencies over the IRP planning period.[9]

Q. PLEASE ELABORATE ON WHY THE COMPANIES' IRP ASSUMPTIONS REGARDING EXPIRING WHOLESALE CONTRACTS ARE REASONABLE AND PRUDENT.

A. As first explained in the Companies' Reply Comments, it is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally enforceable commitment guaranteeing delivery exists. QF owners have unfettered rights to make a business decision at the time their current PPA expires

[9] Reply Comments, at 44-45.

whether or not to establish a new legally enforceable obligation and contractually commit to deliver their full output, including capacity, to the utility, whether to cease operations after their current contract expires, or whether to otherwise use their facility in any lawful manner they so desire, based on the current economic, regulatory, and market circumstances existing at the time their current PPA expires.

For example, market forces including the impact of recently declining natural gas prices as well as regulatory policy changes such as HB 589's modification of standard offer eligibility in North Carolina could impact QF owners' decision-making regarding whether to enter into a new long-term avoided cost contract with the Companies or to sell power off-system. Notably, the Companies' Schedule PP also provides QFs the option to sell energy "as available" versus committing to deliver both energy and capacity pursuant to a legally enforceable obligation.

Additionally, the Companies and their customers have no guarantee that the contracted facility will be physically capable of providing energy and capacity beyond the contract period. The facility may have degraded mechanically, may have lost its land lease or may lack the operations and maintenance funding to run beyond the contracted period.

For these reasons, the Companies' IRPs have consistently and appropriately assumed that all wholesale purchase contract capacity is removed in the year after a wholesale contract expires and that QFs are not presumptively assumed to establish a new legally enforceable obligation to deliver capacity and energy to the utilities over a new fixed term in the future.

Q. AT WHAT POINT DO THE COMPANIES RECOGNIZE A RENEWING QF AS COMMITTING TO SELL ENERGY AND PROVIDE CAPACITY FOR IRP PLANNING PURPOSES?

A. The Companies recognize an operating QF proposing to enter into a new PPA as committing to sell its energy and to deliver capacity for IRP planning purposes when the QF enters into a new PPA for a future term.

Q. ARE THE COMPANIES ALSO PROPOSING TO ADDRESS THE PUBLIC STAFF'S AND INTERVENORS' INTEREST IN PROVIDING MORE TRANSPARENCY REGARDING THE COMPANIES' FIRST YEAR OF AVOIDABLE CAPACITY NEED IN FUTURE IRPs?

A. Yes. As stated in Duke's Reply Comments, the Companies recognize the Public Staff's and other parties' interest in this issue and request for a clearer presentation of the timing of new capacity additions and deficits, specifically including the treatment of QF projects. The Companies have therefore agreed to more clearly address this issue in future IRPs within a new Statement of Need Section, as recommended by the Public Staff.[10] Specifically, the Companies will include in future IRPs an identification of

[10] Reply Comments, at 47. The Companies also addressed this commitment in their recent IRP reply comments filed on May 20, 2019.

the first year of an avoidable need along with the supporting factors used to determine the avoidable need date.

Q. **WILL QFs CONTINUE TO BE PAID FOR CAPACITY IN EACH YEAR OF THE SCHEDULE PP PPA TERM?**

A. Yes. While the calculation of the avoided capacity rate does not include value for capacity until the first year of capacity need arises, the avoided capacity cost rate design levelizes the avoided capacity payment and pays QFs for capacity in each year throughout the contract term.

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

Q. **WHAT DATES HAVE THE COMPANIES USED IN THE CALCULATION OF THE SCHEDULE PP'S AVOIDED CAPACITY RATE?**

A. Consistent with the design of the biennial standard offer in North Carolina, as well as past calculations of avoided capacity under the peaker methodology, the Companies' Schedule PP rates are based on the immediate ten years beginning with the year immediately following the filing of the new rate schedule. The Companies filed the new Schedule PP rates in November 2018 and accordingly used the ten-year period 2019 through 2028 for the calculation. These rates are then available for a two-year period (traditionally through November of the next biennial filing year) at which time updated rates are calculated as required by North Carolina's implementation of PURPA (N.C. Gen Stat. § 62-156(b)).

Q. WHAT ISSUE DOES NCSEA RAISE REGARDING THE COMPANIES' PROPOSED IN-SERVICE DATE FOR STANDARD OFFER QFs?

A. NCSEA contends that the Companies' avoided capacity calculations include "unrealistic assumptions" about when QFs will begin providing capacity to the utilities, based upon "well documented delays" in the Companies' interconnection queue. NCSEA argues that the Companies should delay the presumptive QF in-service date for purposes of calculating avoided capacity costs further into the future, specifically, to December 31, 2021. NCSEA suggests that using this date would recognize that QFs provide a capacity value to the Companies in later years when the Companies have identified a future capacity need. In summary, NCSEA makes a "results-oriented" argument predicated on the fact that further into the future, the Companies' capacity need is greater, thereby providing QFs increased capacity revenues by assuming they would provide capacity at a later time when capacity has a higher economic value to the Companies.

Q. HOW DO THE COMPANIES RESPOND TO THIS ARGUMENT?

A. The Companies reject NCSEA's arguments. As explained in the Companies' Reply Comments, the factual basis underlying NCSEA's argument is simply incorrect. First, NCSEA's factual premise that smaller QFs eligible for the standard offer will not enter into service for multiple years is unsupported and inaccurate—small QFs 1 MW or less proceeding under Section 3 Fast Track and Supplemental Review interconnection processes routinely complete construction and are placed in service in less than a year. Therefore, because the Companies' Schedule PP is limited to QFs 1 MW or less, these QFs proceed to interconnection quickly. Moreover, NCSEA ignores that existing, operating QFs seeking to enter into a new PPA under Schedule PP at the time their existing PPA expires will begin delivering immediately at the conclusion of their prior contract term. Finally, to the extent a QF seeks to "time its legally enforceable obligation" closer to its actual in-service date to obtain a different capacity valuation or avoided cost rates, a QF can always delay the point at which it opts to establish a legally enforceable obligation, or elect to pursue a negotiated PPA versus seeking to sell to the Companies under the Schedule PP standard offer.

Q. DOES THE PUBLIC STAFF AGREE WITH THE COMPANIES' PROPOSED IN-SERVICE DATE?

A. Yes. For purposes of establishing the term for a standard offer facility, the Public Staff comments that the Companies' 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. As such, the Companies' approach to calculating avoided capacity costs is reasonable, and NCSEA's arguments suggesting otherwise should be rejected.

II. RATE DESIGN STIPULATION

Q. PLEASE DESCRIBE THE COMMISSION'S DIRECTION REGARDING THE AVOIDED COST RATE DESIGN.

A. The Commission's *2016 Sub 148 Order* specifically ordered the Companies to consider "a rate scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during the critical peak demand periods."[11] The Commission's *2018 Scheduling Order* similarly directed the Companies to "file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer peak periods, with more granularity than the current Option A and Option B rate schedules."[12]

Q. PLEASE DESCRIBE THE COMPANIES' INITIALLY FILED ENERGY AND CAPACITY RATE DESIGN.

A. The Companies' initial proposal eliminated the pre-existing Option A and Option B rate structures and developed updated, more granular rate designs to better recognize the value of QF energy and capacity. However, the Companies also sought to balance a more granular design with administrative considerations to aid customers in responding to the Schedule PP tariffs' price signals.

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[11] *2016 Sub 148 Order,* at 56.
[12] *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing,* at 1-2, Docket No. E-100, Sub 158 (June 26, 2018) ("2018 Scheduling Order").

The initially proposed Schedule PP rate structure for energy payments defined the summer period as May through September and the non-summer period as October through April. Under this initial design, the avoided energy pricing structure included five pricing periods, each with an independent price block to better reflect the value of QF energy during the different periods. The definition of the specific energy pricing hours also varied slightly for DEC and DEP to account for differences in each utility's load profile, net of solar generation. The initially proposed capacity pricing structure independently defined the specific periods where capacity needs are the greatest and differed from the energy pricing periods. Capacity credits under this initial pricing structure were proposed during specified on-peak hours during the summer months of July and August and winter months of December, January, February and March. On-peak capacity pricing has a defined set of PM hours during the summer period, and both AM and PM hours during the winter period. No capacity credits are applicable in all other months.

Q. HOW DID THE PUBLIC STAFF RESPOND TO THE COMPANIES' RATE DESIGN PROPOSAL?

A. The Public Staff's initial comments stated that the Companies' proposed rate design "compl[ies] with the Commission's directive to propose more granular rates," but suggested that additional granularity, beyond what the Companies had initially proposed was "appropriate and beneficial to North

Carolina ratepayers."[13] The Public Staff therefore proposed an alternative, more granular rate design and methodology to "improve price signals to generators and better align rates to those hours when energy and capacity have the highest value to customers."[14]

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S INITIAL RATE DESIGN PROPOSAL.

A. The Public Staff's avoided energy rate design proposal followed a three-step process summarized as follows: (1) establishment of seasons using historical load data; (2) establishment of off-peak, on-peak, and premium peak hours using a blend of five years of historical marginal pricing and five years of projected marginal pricing ("Blended Hourly Prices"); and (3) classification of premium peak hours as those with Blended Hourly Prices at or above the 90th percentile, and classification of on-peak hours as those with Blended Hourly Prices above the seasonal average. The methodology expanded on the Companies' design and resulted in an energy rate design focused on more granularly defined premium peak hours and additional shoulder month periods to further distinguish rates in more critical summer and winter seasons as compared to the Companies' initially proposed Schedule PP rate design. The Public Staff initially accepted the Companies' capacity pricing design as being reasonable.

[13] Initial Comments of the Public Staff, at 48, 54, (filed Feb. 12, 2019) ("Public Staff Initial Comments").
[14] *Id.* at 48.

65

Q. HAVE THE PARTIES ATTEMPTED TO RESOLVE THEIR DIFFERENCES REGARDING THE REVISED RATE DESIGN?

A. Yes. The Companies have worked with the Public Staff, as well as engaged in discussions with other interveners, to propose an updated energy rate design in Schedule PP that better adheres to the Public Staff's stated premise that, "to the extent possible, avoided energy costs should reflect each utility's actual avoided production cost."[15]

Q. PLEASE PROVIDE AN OVERVIEW OF THE STIPULATION.

A. The Stipulation adopts a modified version of the Public Staff's three-step rate design approach that sets forth the factors that are important to the determination of the Companies' rate design. Applying this methodology, energy and capacity periods are identified that best reflect the Companies' individual avoided cost based upon seasonal and time-of-day characteristics. The more granular rate design agreed to in the stipulation is consistent with the Commission's order in the prior avoided cost docket and conforms with the fundamental indifference or "but for" principle of PURPA ensuring customers are not paying more than the actual costs avoided by the utility.

[15] *Id.* at 54.

Q. PLEASE DESCRIBE THE METHODOLOGY RECOMMENDED FOR USE IN ESTABLISHING THE ENERGY AND CAPACITY RATE DESIGN.

A. The methodology considers such factors as: (1) historic, forecasted or combination of system load, (2) historic and forecasted marginal energy cost, (3) loss of load expectation and hourly capacity value, and (4) technological changes in customer usage, such as the impact of electric vehicles, or the addition of distributed generation or batteries. Due to the fact that avoided cost rates are fixed for the term of the PPA, it is important to not be overly formulaic in the methodology because a brief pricing period may no longer reflect actual higher system costs in the later years of the contract. The rate periods must not, however, be set on too broad a period because doing so can reduce price differentials and yield less incentive for generators to produce power during times that are of the most value to the utility and its customers. Therefore, the updated methodology considers: (1) establishing seasons based upon a review of hourly system load data during each month of the year; (2) determining loads and marginal costs to be used for On-Peak, Off-Peak, and Premium Peak classification; and (3) using the load and marginal cost data to classify hours by season (i.e., On-Peak, Off-Peak, and Premium Peak hours).

Q. HOW DOES THE STIPULATION DIFFER FROM THE COMPANIES' AND PUBLIC STAFF'S INITIAL RATE DESIGN PROPOSALS?

A. Overall, the proposed Stipulation avoided cost rate designs are generally consistent with the initial designs offered by both the Companies and the Public Staff, and seek to better balance the need for a granular rate design while providing Schedule PP customers clear and consistent price signals that will be sustainable over their contract terms. The stipulated rate designs adopt many of the features of the Public Staff's initially-proposed avoided energy design, such as premium peak hours and shoulder seasons, but redefine the hours of the peak periods to recognize the dynamics surrounding system load that could easily shift the time of system peak conditions in the future.

Q. PLEASE DESCRIBE THE AVOIDED ENERGY RATE DESIGN PROPOSED IN THE STIPULATION.

A. The marginal energy rate structure includes summer, winter and shoulder seasons. Applying the stipulated rate design methodology, the Summer energy season is defined to include June, July, August, and September; the Winter energy season is defined to include December, January, and February; and the Shoulder energy season is defined to include March, April, May, October, and November. The design reflects nine energy pricing periods to reflect the energy value of QF generation during the different time frames.

The hourly energy rate periods reflect the concept of including higher-priced rating periods, called premium peak hours, in the Companies' Winter and Summer seasons. These premium peak hours provide the highest rates to incent generation during these hours when it is most advantageous for customers. Days with premium-peak and on-peak hours include Monday through Friday, excluding certain holidays. On-peak energy pricing has a defined set of PM hours during the summer period and both AM and PM hours during both the winter and shoulder periods. Off-peak hours within each season include all hours not otherwise defined as premium or on-peak, and include certain holidays.

Q. PLEASE DESCRIBE IN MORE DETAIL THE ENERGY RATING PERIODS PROPOSED FOR DEC.

A. For energy credit purposes, Summer months are defined as calendar months June through September and Winter months are defined as calendar months December through February. All other months are defined as Shoulder months. On Monday through Friday, Summer premium-peak hours are from 4:00 p.m. to 8:00 p.m. and on-peak hours are from 12:00 p.m. noon to 4:00 p.m. plus 8:00 p.m. to 10:00 p.m. On Monday through Friday, Winter premium-peak hours are from 6:00 a.m. to 9:00 a.m. and winter morning (or AM) on-peak hours are from 5:00 a.m. to 6:00 a.m. plus 9:00 a.m. to 10:00 a.m. while winter evening (or PM) on-peak hours are from 5:00 p.m. to 10:00 p.m. On Monday through Friday, Shoulder on-peak hours are 6:00 a.m. to 10:00 a.m. plus 4:00 p.m. to 11:00 p.m. All other hours within each of the defined seasons, plus the following holidays, are off-peak: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and the day after, and Christmas Day. When a holiday falls on a Saturday, the Friday before the holiday will be considered off-peak; when the holiday falls on a Sunday, the following Monday will be considered off-peak.

Q. PLEASE DESCRIBE IN MORE DETAIL THE ENERGY RATING PERIODS PROPOSED FOR DEP.

A. For energy credit purposes, Summer months are defined as calendar months June through September and Winter months are defined as calendar months December through February. All other months are defined as Shoulder months. On Monday through Friday, Summer premium-peak hours are from 4:00 p.m. to 8:00 p.m. and Summer on-peak hours are from 1:00 p.m. to 4:00 p.m. plus 8:00 p.m. to 9:00 p.m. On Monday through Friday, Winter premium-peak hours are from 6:00 a.m. to 9:00 a.m. and Winter morning (or AM) on-peak hours are from 4:00 a.m. to 6:00 a.m. plus 9:00 a.m. to 11:00 a.m. with evening on-peak hours from 6:00 p.m. to 10:00 p.m. On Monday through Friday, Shoulder on-peak hours are from 5:00 a.m. to 10:00 a.m. plus 5:00 p.m. to 11:00 p.m. All other hours within each of the defined seasons, plus the following holidays, are off-peak: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and the day after, and Christmas Day. When a holiday falls on a Saturday, the Friday before the holiday will be considered off-peak; when the holiday falls on a Sunday, the following Monday will be considered off-peak.

Q. WHAT METHOD DOES THE STIPULATION RECOMMEND FOR PAYING QFs FOR CAPACITY VALUE?

A. QF capacity rates are paid on a per-kWh basis across a pre-determined set of seasonal hours that represent the hours most likely to have capacity value. Paying QFs for capacity on a per-kWh basis is consistent with the approach the Companies have historically utilized with respect to QF rate design under prior vintages of Schedule PP. The Public Staff and the Companies agree in the Stipulation that it is reasonable and appropriate to adopt the Companies' seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the Astrapé Solar Capacity Value Study. The loss of load risk identifies the times when the Companies forecast generation constraints making QF generation of the greatest value to customers.

Q. PLEASE DESCRIBE THE AVOIDED CAPACITY RATE DESIGN PRESENTED IN THE STIPULATION.

A. The avoided capacity rate design reflects changes to the pre-existing seasonal allocation weighting for capacity payments. The new Schedule PP capacity rate design offers three distinct pricing periods to more accurately reflect the marginal capacity value to customers during each period. The pricing periods offer capacity payments during the PM hours in the summer months of July and August and both AM and PM hours in the winter months of December, January, February and March. No capacity payments apply during the remaining months. The highest prices are paid in the early morning winter hours to recognize the greater loss of load risk and greater value of capacity during those hours. The seasonal months and three capacity pricing periods are the same for DEC and DEP. Compared to the pre-existing rate design, the three distinct pricing periods focus on fewer hours and more accurately reflect the value of QF capacity to ensure customers are paying for QF capacity that actually reduces the utilities' needs for future capacity.

Q. PLEASE DESCRIBE THE AVOIDED CAPACITY RATING PERIODS PROPOSED FOR DEC AND DEP UNDER THE STIPULATION.

A. Summer on-peak hours are 4 p.m. to 8 p.m. during all Summer days. During Winter months, the morning on-peak (or AM) hours are all Winter days from 6:00 a.m. to 9:00 a.m. and evening (or PM) on-peak hours are all Winter days from 6:00 p.m. to 9:00 p.m.

Q. PLEASE DESCRIBE THE SEASONAL ALLOCATION OF CAPACITY COST AGREED TO IN THE STIPULATION.

A. The new seasonal allocation is heavily weighted to winter based on the impact of summer versus winter loss of load risk. The seasonal allocation is driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. As presented in the Companies' 2018 IRPs, 100% of

DEP's loss of load risk occurs in the winter and approximately 90% of DEC's loss of load risk occurs in the winter. Thus, DEP's new rates pay all of its annual capacity value in the winter while DEC's new rates pay 90% of its annual capacity value in the winter and the remaining 10% in the summer period.

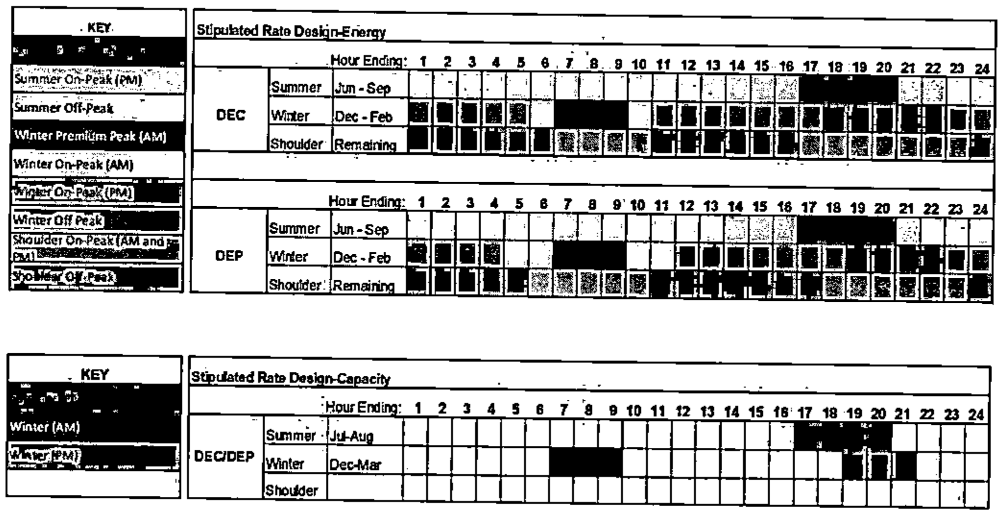
Q. DOES THE STIPULATION PRESENT A GRAPHIC PRESENTATION OF THE AVOIDED CAPACITY AND AVOIDED ENERGY RATE DESIGN PERIODS?

A. Yes. Exhibit A to the Stipulation provides a graphic summary of the avoided capacity and avoided energy rate design pricing periods. I have also presented this information in my Figure 1 and Figure 2:

<u>Figure 1: Stipulated Energy and Capacity Seasons (By Month)</u>

Stipulated Seasons	DEC/DEP	DEC/DEP
Month	Energy	Capacity
January	Winter	Winter
February	Winter	Winter
March	Shoulder	Winter
April	Shoulder	
May	Shoulder	
June	Summer	
July	Summer	Summer
August	Summer	Summer
September	Summer	
October	Shoulder	
November	Shoulder	
December	Winter	Winter

Figure 2: Stipulated Energy and Capacity Rate Periods (By Hour)



Q. DO YOU BELIEVE THE AVOIDED ENERGY AND AVOIDED CAPACITY RATE DESIGNS AS PRESENTED IN THE STIPULATION ARE REASONABLE AND ACCURATE?

A. Yes. The updated rate designs reasonably and accurately reflect the avoided cost value of QF energy and capacity being delivered to the Companies and paid for by customers. The proposed rate design contained in the Stipulation will also provide strong price signals to QFs by identifying the times that generation is of the most value to customers and providing a financial incentive to maximize their generation during these higher production cost hours. Thus, the design encourages QFs to configure their operating scheme to take advantage of these higher rate periods when energy and capacity are of the highest value to customers.

Q. HOW DO THE STIPULATED SCHEDULE PP RATE DESIGNS COMPARE TO THE COMPANIES' PRE-EXISTING SUB 148 SCHEDULE PP OPTION A AND B RATE DESIGNS?

A. Consistent with the Commission's *2016 Sub 148 Order*, the Companies' and Public Staff's stipulated rate design more appropriately matches the value of energy and capacity received by customers from QFs to the value paid by customers for QF generation. As illustrated by my Figures 3 and 4 below, customers would overpay QFs by thousands of dollars for a generic 1 MW solar generator under the pre-existing Schedule PP Option A and Option B rate designs as compared to the stipulated rate design. For comparison, the following example uses the same underlying annual avoided cost values in this docket and simply isolates the impact of moving to the new more granular rate design.

Based on a typical solar profile, for DEC, the new stipulated rate design results in a decrease in customer payments of approximately 10% when compared to the same solar production profile and costs but with rates calculated under the old Option A rate design and 7% when calculated under the old Option B rate design. Figure 3 below illustrates this comparison for DEC.

Figure 3: DEC Rate Design Comparison

DEC COMPARISON OF ESTIMATED PAYMENTS TO SOLAR FACILITY UNDER DIFFERENT RATE DESIGNS (in 000s)			
Input Cost Data (same for all)	Cost Per E-100, Sub 158	Cost Per E-100, Sub 158	Cost Per E-100, Sub 158
Rate Design (3 methods)	Per E-100, Sub 158 Stipulation (Proposed method)	Per E-100, Sub 148 Option A (Prior method no longer offered)	Per E-100, Sub 148 Option B (Prior method no longer offered)
Scenario	(1) Stipulation - Solar	(2) Option A - Solar	(3) Option B - Solar
Energy Credit	$ 66	$ 72	$ 70
Capacity Credit	1	$ 2	$ 2
Total Annual Payment	$ 67	$ 74	$ 72
Annual Payment x 10 years	$ 666	$ 736	$ 719

For DEP, the new stipulated rate design results in a decrease in customer payments of approximately 19% when compared to the same solar production profile and costs but with rates calculated under the old Option A rate design and a 25% decrease when calculated under the old Option B rate design. Figure 4 below illustrates this comparison for DEP.

Figure 4: DEP Rate Design Comparison.

DEP COMPARISON OF ESTIMATED PAYMENTS TO SOLAR FACILITY UNDER DIFFERENT RATE DESIGNS (in 000s)			
Input Cost Data (same for all)	Cost Per E-100, Sub 158	Cost Per E-100, Sub 158	Cost Per E-100, Sub 158
Rate Design (3 methods)	Per E-100, Sub 158 Stipulation (Proposed method)	Per E-100, Sub 148 Option A (Prior method no longer offered)	Per E-100, Sub 148 Option B (Prior method no longer offered)
Scenario	(1) Stipulation - Solar	(2) Option A - Solar	(3) Option B - Solar
Energy Credit	$ 62	$ 64	$ 64
Capacity Credit	4	$ 17	$ 24
Total Annual Payment	$ 66	$ 82	$ 88
Annual Payment x 10 years	$ 659	$ 817	$ 878

It should be noted that while the new more granular energy rates better align energy value with the payments customers make for avoided energy, the largest impact of the new rate design is in the capacity payment. Simply put, the legacy Sub 148 Option A and Option B rate designs resulted in customers paying for capacity well in excess of the capacity benefits they received. In summary, the new more granular rate design more appropriately aligns the avoided capacity and energy rates with the Companies' avoided cost, and, as a result, will reduce customer overpayment while appropriately compensating QFs for the actual energy and capacity costs avoided.

Q. IN YOUR VIEW, IS THE RATE DESIGN PRESENTED IN THE STIPULATION RESPONSIVE TO THE COMMISSION'S PRIOR DIRECTION AND THE RESULT OF GOOD FAITH NEGOTIATIONS BETWEEN THE COMPANIES AND THE PUBLIC STAFF?

A. Yes. Consistent with the Commission's direction in the *2016 Sub 148 Order*, as discussed above, the rate design presented in the Stipulation pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during critical peak demand periods. The Stipulation rate design also reflects the Companies' highest production cost hours with more granularity than the current Option A and Option B rate schedules, as directed by the Commission's *2018 Scheduling Order*. Finally, the Stipulation reflects good faith negotiations between the Companies and the Public Staff to resolve these issues and is responsive to the Commission's directives.

III. ANCILLARY SERVICES COST

1. Quantification of Ancillary Services Cost of Integrating QF Solar

Q. DID THE COMPANIES INCLUDE ANY SPECIFIC CHARGES OR ADJUSTMENTS TO THE AVOIDED COST RATES FILED IN THIS PROCEEDING TO ACCOUNT FOR MEASURABLE COSTS OF INSTALLING INTERMITTENT QF SOLAR POWER?

A. Yes. The Companies included a specific, measurable Integration Services Charge applicable to intermittent solar generation.

Q. PLEASE ELABORATE ON THE COMMISSION'S DIRECTION CONCERNING THE INCLUSION OF ANCILLARY SERVICES CHARGES FOR INTERMITTENT RESOURCES.

A. The *2018 Scheduling Order* directed the Companies to consider factors relevant to the characteristics of QF-supplied power—specifically intermittent and non-dispatchable power—in designing rates to meet PURPA's objectives of appropriately valuing the Companies' incremental costs of alternative energy to be avoided from purchasing power from a QF.[16] As explained in the Companies' Reply Comments, the Commission's *2016 Sub 148 Order* emphasized that it would be appropriate for the Utilities to propose schedules "specific to QFs that provide intermittent, non-dispatchable power, if the Utilities' cost data 'demonstrates marked differences' in the value of the energy and capacity provided by these

[16] *2016 Sub 148 Order*, at 98.

QFs."[17] As discussed in the Companies' Joint Initial Statement and Reply Comments, the Companies have determined that the costs avoided by growing levels of solar QFs that provide intermittent, non-dispatchable power is markedly different from integrating firm power and that it is appropriate to recognize integration costs in valuing the energy and capacity provided by QFs eligible for Schedule PP.

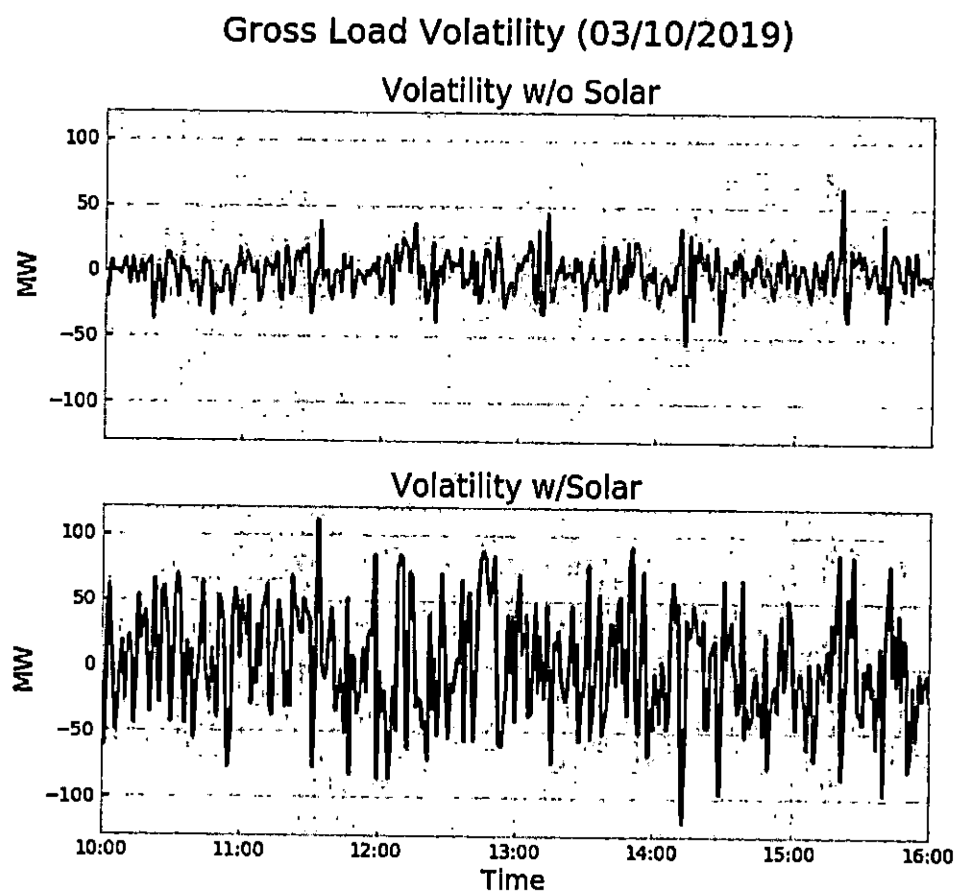
Q. PLEASE EXPLAIN HOW INTEGRATING INCREASING LEVELS OF INTERMITTENT SOLAR RESOURCES IS INCREASINGLY IMPACTING SYSTEM OPERATIONS GENERALLY, INCLUDING DISPATCH OF THE COMPANIES' CONVENTIONAL GENERATING FLEETS.

A. To meet the Companies' obligation to provide reliable electric service to their customers, DEC and DEP must dispatch their generation fleet resources to meet real-time load on a moment-to-moment basis. The energy output from solar resources is variable; it can unexpectedly and rapidly drop-off or ramp-up in real-time, thereby increasing uncertainty in day-ahead, hourly, and sub-hourly projections for fleet operations. This addition of solar volatility to the system increases the real-time volatility the system experiences as compared to just servicing load without solar on the system. Figure 5 is a simple example that depicts volatility of load without solar as compared to the volatility of load plus solar on the DEP system on a recent spring day, March 10, 2019. This example shows how

[17] *2018 Scheduling Order*, at 1-2.

the addition of solar significantly increases the volatility during the 10:00 a.m. to 4:00 p.m. period when "must-take" solar production was being put to the system.

Figure 5: DEP Load and Solar Volatility on March 10, 2019



The increased solar volatility experienced on March 10, 2019 is also not an anomaly. My Exhibit 1 provides a similar graphic presentation of how the addition of solar increases system volatility on the DEP system during each of the first 10 days in March 2019. Reviewing the volatility that occurred each day also highlights another key point: no two days are the same. Solar volatility can change significantly both day-ahead and intra-day resulting in operational uncertainty as to precisely when and how much solar will show up on a given day. Importantly, this additional uncertainty and volatility requires the Companies to carry additional operating reserves, which are the real-time system resources required to balance and regulate the system on an hourly and sub-hourly basis. These operating reserves are provided by reserving additional dispatchable conventional fleet resources to ensure that sufficient operational flexibility is available to respond in real-time to rapid changes in solar output. Additionally, ensuring that sufficient operating reserves are available is also required to maintain compliance with NERC bulk electric system balancing and reliability standards. The need for increased real-time system operating reserves to reliably integrate increased levels of uncontrolled must-take solar generation results in additional operating costs relative to a dispatchable or baseload generation source.

Q. **HOW DID THE COMPANIES QUANTIFY THE INCREASED OPERATING COSTS THAT THEY INCUR TO RELIABLY INTEGRATE THE UNCONTROLLED SOLAR QF GENERATION ON THEIR RESPECTIVE SYSTEMS THAT YOU DESCRIBE ABOVE?**

A. In late 2017, the Companies commissioned Astrapé Consulting to analyze the impacts of integrating solar into the Companies' systems at varying solar penetration levels and to quantify the cost of utilizing the DEC and

DEP conventional fleets to provide the additional operating reserves or generation "ancillary services" needed to reliably integrate the various levels of intermittent solar generation. As introduced above, Witness Wintermantel of Astrapé Consulting is testifying in this proceeding as to the methodology and results of the Solar Ancillary Service Study conducted for DEC and DEP.

Q. PLEASE PROVIDE A HIGH LEVEL EXPLANATION OF THE FACTORS THAT INFLUENCE THE INTEGRATION COSTS FOR THE DEC AND DEP SYSTEMS.

A. As discussed in Witness Wintermantel's testimony, the cost to carry additional ancillary services required to reliably integrate solar generation into a utility's system is driven by several factors. In general terms, these factors include the characteristics and make-up of dispatchable generation resources within a utility's existing system, the underlying cost of the fossil fuels used by those resources, the nature of the utility's load profile and the amount, size and locational diversity of solar resources installed on the utility's system.

Q. IS THE COMPANIES' METHODOLOGY AND APPROACH TO FIXING THE INTEGRATION SERVICES CHARGE REASONABLE AND CONSISTENT WITH PRIOR COMMISSION DIRECTIVES?

A. Yes. The proposed Integration Services Charge supported by the Astrapé Study meets the Commission's directive in the *2016 Sub 148 Order* to focus on improving the Schedule PP rate design in ways that do not adversely impact other small power producer technologies for "problems that are specifically related to solar."[18] The Companies' proposed Integration Services Charge additionally addresses the Commission's directives to address the "characteristics of QF-supplied power," in how the Companies are incurring ancillary services costs due to the volatility and intermittency of integrating QF solar.

Specifically, the Integration Services Charge included in Schedule PP is designed to reflect the average integration cost for all solar resources operating on the system versus assigning the full "incremental" integration costs to new solar resources. The charge is also based only on existing plus HB 589 transition ("Existing Plus Transition") solar capacity in DEP (2,950 MW) and DEC (840 MW), as opposed to the significantly higher incremental integration cost which results when valuing the integration cost impacts for solar above the existing plus HB 589 transition requirements.

Q. PLEASE PRESENT THE VALUES OF THE INTEGRATION SERVICES CHARGES INCLUDED IN DEC'S AND DEP'S SCHEDULE PP AVOIDED COST TARIFFS.

A. Separate solar Integration Services Charges are included in Schedule PP for DEC and DEP. For DEC, the charge is $1.10/MWh. For DEP, the charge is $2.39/MWh. The difference in the DEP and DEC cost is largely

[18] *2016 Sub 148 Order*, at 49-50.

driven by the significantly greater amount of Existing Plus Transition solar capacity in DEP (2,950 MW) compared to DEC (840 MW).

Q. WILL THE INTEGRATION SERVICES CHARGE BE UPDATED?

A. Yes. As further discussed by Witness Wheeler, the Integration Services Charge within a solar provider's contract will be updated biennially during future avoided cost proceedings to reflect changes in the Companies' average ancillary services costs as additional solar generation is installed on the DEC and DEP systems over time. This will allow for the uniform application of the charge and will also account for changes in market factors impacting the cost of integration over time.

Q. WHICH SOLAR GENERATORS WILL INCUR THE SOLAR INTEGRATION SERVICES CHARGE?

A. As explained in the Stipulation and further supported by Witness Wheeler, all solar QFs selling power to DEC and DEP under the Schedule PP avoided cost rates filed in this proceeding will be subject to this Integration Services Charge. The Companies are not proposing to apply this charge retrospectively to existing solar resources or to those solar resources that have established contracts under previously-authorized long-term fixed rates. As existing contracts with solar QFs expire, however, any new solar contracts, or contract renewals, would include such a provision. As such, the Companies plan to update the Integration Services Charge as a normal part of future avoided cost filings to account for changes in the previously-mentioned factors, such as solar penetration levels, prevailing fuel prices and the makeup of the Companies' future resource portfolios. Thus, over time, as existing contracts expire and new contracts are executed, this average Integration Services Charge will apply to all solar providers.

Q. HAVE THE COMPANIES ALSO RECENTLY AGREED TO CAP FUTURE ADJUSTMENTS TO THE INTEGRATION SERVICES CHARGE APPLICABLE TO A GIVEN VINTAGE OF QFs?

A. Yes. As discussed by Witness Wheeler, the Companies have recently entered into a Stipulation with the Public Staff agreeing to "cap" future adjustments to the biennially-adjusted Integration Services Charge. As Witness Wheeler explains, the cap is designed to balance mitigating financial risk to QFs of future potential increases in the average ancillary services charge applied to QFs over time while sending appropriate price signals to QFs based upon the Companies' most current ancillary services costs. A cap is established for each biennial vintage of solar QFs at the time they initially contract to sell power under Schedule PP and will be based upon the same methodology used to quantify the Integration Services Charge, as further discussed by Witness Wintermantel.

Q. HOW ARE THE COMPANIES' CUSTOMERS IMPACTED IF INTEGRATION COSTS ARE NOT CHARGED TO SOLAR QFs AS A DECREMENT TO AVOIDED COSTS, AS PROPOSED IN THE SCHEDULE PP TARIFF?

A. As further discussed by Witness Wheeler, if an adjustment is not made to the avoided cost tariff to account for these specific operational costs driven by the integration of intermittent solar resources, then the Companies' customers bear this cost, which is recovered in the annual fuel cost proceeding. Failure to properly charge these solar integration costs to the cost causer – *i.e.*, the intermittent solar QF – would unfairly burden the Companies' customers with increased costs and would violate the ratepayer indifference objective underlying PURPA.

Q. IS THE INTEGRATION SERVICES CHARGE FAIR TO THE SOLAR QF GENERATORS AND THE COMPANIES' CUSTOMERS?

A. Yes. The Integration Services Charge properly attributes these costs to the appropriate cost causer, as opposed to imposing additional costs on the Companies' customers, and that the Companies have reasonably and fairly implemented the charge to intermittent solar QFs on a prospective basis.

2. <u>Response to NCSEA's and Public Staff's Proposal Related to Differing Ancillary Services Costs for Innovative QFs</u>

Q. WHAT PROPOSALS DO INTERVENORS MAKE RELATED TO DIFFERING ANCILLARY SERVICES COSTS FOR INNOVATIVE QFs?

A. The Public Staff and NCSEA through their comments contend that certain QFs have the technical capability to reduce the additional ancillary services caused by the operation of solar QFs delivering intermittent energy to the Companies.

Q. HOW DO THE COMPANIES RESPOND TO THESE PARTIES' PROPOSALS?

A. During discussions with the Public Staff, the Companies evaluated the concept of innovative QFs potentially providing ancillary services and/or reducing the additional ancillary services otherwise required to be provided by the Companies' conventional fleets to integrate solar QFs. As a result of these discussions, and as further discussed by Witness Wheeler, the Companies have agreed in the Stipulation that solar QFs that demonstrate that their facilities materially reduce the need for increased incremental ancillary service requirements will not incur the Integration Services Charge. Specifically, solar generators who are not "must take" QFs and who contractually agree to operate their facilities through use of energy storage devices, dispatchable contracts, or other mechanisms that reduce or eliminate the intermittency of the facilities' generation output can eliminate the Companies' additional ancillary services costs and therefore appropriately avoid the Integration Services Charge designed to recover these costs.

IV. PROPOSED MODIFICATIONS TO THE STANDARD TERMS AND CONDITIONS

Q. PLEASE DISCUSS WHY THE COMPANIES HAVE PROPOSED CHANGES TO THEIR PPA AND TERMS AND CONDITIONS.

A. As discussed in greater detail by Witness Johnson, the Companies have modified certain provisions of DEC's and DEP's standard Schedule PP

PPA and Terms and Conditions to clarify that operational QFs should not be allowed to modify their generating facility in order to increase their generation output beyond initially contracted-for levels. To do so at pre-existing avoided cost rates that now significantly exceed DEC's or DEP's current avoided costs would be unjust and unreasonable and would result in significant customer overpayment relative to the incremental generation value being put to the grid.

Q. PLEASE EXPAND ON WHY THESE CHANGES TO THE SCHEDULE PP PPA AND TERMS AND CONDITIONS ARE NECESSARY.

A. In addition to the reasons identified by Witness Johnson, the Companies' modifications to the PPA and Terms and Conditions are necessary, first and foremost, to protect customers from overpaying QFs who seek to increase their agreed upon generation output at rates that exceed the utility's current avoided costs. QFs delivering power today at rates fixed under prior vintages of Schedule PP dating as far back as the 2010 E-100, Sub 127 docket should not be allowed to increase the number of panels on their facilities, advance their facility inverters, or co-locate battery storage at their operating facilities in order to increase their generation output and receive additional revenues at rates above the Companies' current avoided costs. The effect of these alterations inappropriately increases the Companies'—and therefore the Companies' customers—financial obligations for the output of these legacy facilities. This would result in continued overpayment to QFs under these historically-approved avoided cost rates that are well in excess of the value to customer that is being provided today. Therefore, the Companies have proposed modifications to the Schedule PP PPA and Standard Terms and Conditions to insulate customers from QFs seeking to unfairly increase their agreed-upon generation capacity without the Companies' consent and to the direct financial detriment of the Companies' customers.

Q. PLEASE EXPLAIN THE QUANTIFIABLE IMPACTS TO CUSTOMERS IF THE COMPANIES ALLOWED OPERATING QFs TO MAKE A "MATERIAL ALTERATION" BY ADDING ADDITIONAL SOLAR PANELS OR ENERGY STORAGE SYSTEMS TO AN EXISTING FACILITY SELLING UNDER NOW-EXCESSIVE AVOIDED COST RATES.

A. As I mentioned earlier, recent changes to North Carolina's PURPA implementation in HB 589 now authorize the Companies to fully recover their QF purchase costs through the annual fuel factor. Thus, customers will directly feel the rate impact if the Companies accepted modifications to QF generating facilities selling power under outdated and now-excessive avoided cost rates. This is a significant issue as DEC and DEP are now committed to purchase the full contracted-for output from over 3,600 MW of currently- or to-be installed QF generating facilities, all of which are subject to rate schedules approved in Docket No. E-100, Sub 140 or earlier vintages that now significantly exceed the Companies' avoided cost.

Purchases from these QFs are projected to result in approximately \$4.5 billion in total financial obligations to QFs over the next approximately 15 years, with the current overpayment risk to customers having now increased to \$2.2 billion.

Any modifications to these contracted QF generating facilities to increase their generator size (MW_{AC}) or their capability to produce energy in more hours of the day (MW_{DC}) will exacerbate the Companies' current financial obligation and increase the current and, likely, future over-payment to QFs in excess of the Companies' actual avoided cost of energy and capacity.

As explained in Figure 11 to Duke's Reply Comments,[19] which I have replicated as Figure 6 to my testimony below, the Companies estimate that if existing QF generating facilities co-locate 2 MW/8MWH energy storage systems at just 10% of the Sub 136 and Sub 140 QF capacity operating today under the Companies' stale and outdated avoided cost rates, this would cost DEC and DEP customers approximately \$17.2 million in additional payments to QFs over the remaining terms of those QF's PPAs.

[19] Reply Comments, at 135.

Figure 6

		Solar Plus Storage Scenarios		
Assumed 15 year rates		Incremental Storage Purchased Power Obligation		
		2 MW/1 Hour	2 MW/ 2 Hour	2 MW/ 4 Hour
DEP Sub 136 - 2MW Battery	Total Cost	$25,359,134	$42,795,832	$72,847,817
DEP Sub 140 - 2MW Battery	Total Cost	$19,732,691	$33,011,248	$57,499,269
DEP	Total Cost	$45,091,825	$75,807,080	$130,347,086
DEC Sub 136 - 2MW Battery	Total Cost	$7,736,619	$13,148,120	$23,729,217
DEC Sub 140 - 2MW Battery	Total Cost	$6,137,573	$10,494,535	$18,547,052
DEC	Total Cost	$13,874,192	$23,642,655	$42,276,268
Duke Totals (100%)	Total Cost	$58,966,017	$99,449,735	$172,623,355
10% of Total		$5,896,602	$9,944,974	$17,262,335
50% of Total		$29,483,009	$49,724,868	$86,311,677

If 50% of the Sub 136 and Sub 140 QF capacity operating today elected to add 2 MW/8MWH battery storage systems, the analysis shows that this additional financial obligation would increase to $86.3 million. This additional financial obligation would further increase to $172.6 million if all Sub 136 and Sub 140 QF capacity operating today elected to add 2 MW/8MWH battery storage systems.

Q. **DO THE COMPANIES' MODIFICATIONS TO THE SCHEDULE PP AND STANDARD TERMS AND CONDITIONS ALSO ALIGN WITH NORTH CAROLINA'S RECENT PURPA POLICY CHANGES ENACTED IN HB 589?**

A. Yes. HB 589 amended N.C. Gen. Stat. § 62-156 to limit eligibility for the utilities' standard offer contracts to QF generating facilities 1 MW or less, and limited negotiated PURPA contracts for QF generating facilities greater than 1 MW to a contract term of no longer than five years. Without the Companies' proposed modifications to the Agreement, existing facilities that are no longer eligible for the standard offer contract would potentially be permitted to retrofit their facilities to increase their generation output and/or extend their system's capability to deliver power over more hours– which would be contrary to the General Assembly's intent in enacting HB 589. Effectively, this would also provide an end-run around the General Assembly's intent to shift solar development to the more competitive and customer-focused programs established in HB 589, and would be contrary to the goals of procuring cost-effective new renewable energy at or below the Companies' avoided cost.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

92

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of:	)	**REBUTTAL TESTIMONY OF**
	)	**GLEN A. SNIDER**
Biennial Determination of Avoided Cost	)	**ON BEHALF OF DUKE**
Rates for Electric Utility Purchases from	)	**ENERGY CAROLINAS, LLC**
Qualifying Facilities - 2018	)	**AND DUKE ENERGY**
	)	**PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glen A. Snider. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. HAVE YOU SUBMITTED DIRECT TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I previously filed direct testimony supporting the Companies' avoided cost filing on May 21, 2019.

Q. PLEASE PROVIDE A SUMMARY AND OVERVIEW OF THE STRUCTURE OF YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony addresses the arguments made by other parties pertaining to Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP") (together, the "Companies" or "Duke") proposed updates to the Companies' Schedule PP avoided cost rates, and modifications to the standard power purchase agreement ("PPA") available to qualifying facilities ("QFs") eligible for Schedule PP and the standard Terms and Conditions for the Purchase of Electric Power ("Terms and Conditions"), which the Companies filed for Commission approval on November 1, 2018. My rebuttal testimony specifically responds to testimony addressing the issues identified in the Commission's April 24, 2019 *Order Scheduling Evidentiary Hearing and Establishing Procedural Schedule* and is organized as follows:

I. Avoided Capacity

1. Treatment of Expiring Wholesale QF PPAs in Calculating Avoided Capacity Rates

2. QF In-Service Date in Calculating Schedule PP Rates

II. Rate Design Stipulation and Seasonal Allocation

III. Ancillary Services Costs

1. Quantification of Ancillary Services Cost of Integrating QF Solar; and,

2. SISC Stipulation and Recognition of Differing Ancillary Services Costs for "Innovative QFs."

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. No.

I. AVOIDED CAPACITY

1. Treatment of Expiring Wholesale QF PPAs in Calculating Avoided Capacity Rates

Q. PLEASE REINTRODUCE THE ISSUES RAISED IN THIS PROCEEDING REGARDING THE COMPANIES' RESOURCE PLANNING APPROACH TO AVOIDED CAPACITY AND EXPIRING QF CONTRACTS.

A. As introduced in my direct testimony[1] and previously addressed in Duke's Reply Comments[2], the broader issue before the Commission is whether the Companies' biennial integrated resource plans ("IRP") appropriately identify DEC's and DEP's next respective incremental capacity need that can be deferred or "avoided" by a utility purchasing capacity and energy from a QF.

The Commission's determination in this regard must be assessed in accordance with Session Law 2017-192's ("HB 589") amendments to North Carolina's PURPA implementation framework. Specifically, N.C. Gen. Stat. § 62-156(b)(3), now expressly provides that "[a] future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] filed with the Commission has identified a projected capacity need to serve system load and the identified need can be met by the type of QF resource based upon its availability and reliability of power, other than swine or poultry waste for which a need is established consistent with G.S. 62-133.8(e) and (f)." I further discuss the meaning of this provision as well as the carve-out establishing a capacity need for contracts with swine and poultry waste generators under North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") later in my testimony.

Q. UNDER NORTH CAROLINA'S PURPA IMPLEMENTATION FRAMEWORK, AS AMENDED BY HB 589, WHAT DOES THE IRP

[1] Duke Snider Direct Testimony, at 7-15.
[2] Duke Reply Comments, at 42-47.

DETERMINATION OF THE UTILITY'S FIRST YEAR OF PROJECTED CAPACITY NEED MEAN IN TERMS OF QUANTIFYING THE UTILITY'S AVOIDED CAPACITY TO BE PURCHASED FROM QFS?

A. HB 589 essentially memorialized into law this Commission's determination in the *2016 Sub 148 Order* that ". . . PURPA was not intended to force a utility and its customers to pay for capacity that it otherwise does not need."[3] This legislative determination reflects the foundational "but for" principle under PURPA that avoided costs paid to QFs are limited to the value to the utility of energy and, when needed, capacity that "but for the purchase from [the QF], such utility would generate or purchase from another source."[4] With the exception of purchases from swine and poultry waste generators, for which an immediate need is established by the REPS Program and for which Duke would recognize and pay for that swine and poultry capacity in the first year of need, HB 589 establishes that any other newly established purchase obligation should only assume a future capacity need is avoided beginning in the first year of need identified in the Companies' most recent biennial IRPs.

Q. **WHEN DO DEC'S AND DEP'S RESPECTIVE BIENNIAL IRPS IDENTIFY EACH UTILITY'S NEXT AVOIDABLE CAPACITY NEED?**

[3] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 48-49, Docket No. E-100, Sub 148 (Oct. 11, 2018) ("*2016 Sub 148 Order*").
[4] 16 U.S. Code § 824a–3(d).

A. As discussed in the Companies' Joint Initial Statement, DEC's and DEP's 2018 biennial IRPs filed in Docket No. E-100, Sub 157 identify the respective utilities' first avoidable capacity need as arising in 2028 and 2020, respectively.[5]

Q. IN MAKING THIS DETERMINATION OF FUTURE CAPACITY NEED, HOW DO THE COMPANIES' IRPS TREAT EXPIRING WHOLESALE CONTRACTS, INCLUDING QF CONTRACTS?

A. As I explained in direct testimony and the Companies previously explained in the Duke Reply Comments, the Companies' IRPs have consistently and appropriately assumed that all wholesale purchase contract capacity is removed in the year after a wholesale contract expires and that QFs are not presumptively assumed to establish a new legally enforceable obligation ("LEO") to deliver capacity and energy to the utilities over a new fixed term in the future.[6] At the time any merchant wholesale generator, including a QF, executes a PPA and commits itself to deliver energy and capacity over a future term, the Companies would then recognize the committed energy and capacity for IRP planning purposes, including as "existing capacity" for purposes of determining the utility's need for additional capacity in the future.

[5] *See* Joint Initial Statement of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, at 13 (filed November 1, 2018), citing Duke Energy Carolinas, LLC 2018 Integrated Resources Plan and 2018 REPS Compliance Plan, at 70, Docket No. E-100, Sub 157 (filed Sept. 5, 2018); Duke Energy Progress, LLC 2018 Integrated Resource Plan and 2018 REPS Compliance Plan, at 72, Docket No. E-100, Sub 157 (filed Sept. 5, 2018).
[6] Duke Snider Direct Testimony, at 12-14; Duke Reply Comments, at 44-45.

Q. DOES THE PUBLIC STAFF SUPPORT DUKE'S OVERALL DETERMINATION OF EACH UTILITY'S NEXT AVOIDABLE CAPACITY NEED AS REASONABLE AND APPROPRIATE FOR PURPOSES OF FIXING AVOIDED CAPACITY COST RATES IN THIS PROCEEDING?

A. Yes. Public Staff Witness John R. Hinton critiques the Companies' IRP assumptions regarding the inter-relationship between expiring wholesale contracts and the continued growth in solar generation on the DEC and DEP systems. However, based upon further discussion and information provided to the Public Staff explaining that modifying the IRP assumptions regarding expiring solar purchase power agreements ("PPAs") would not change either utility's first year of avoidable capacity need, Mr. Hinton testifies that Duke's approach to establishing the first year of needed capacity for avoided cost purposes is reasonable and accepted by the Public Staff for purposes of fixing rates in this proceeding.[7]

Q. SPECIFIC TO DUKE'S TREATMENT OF EXPIRING QF CONTRACTS, DOES THE PUBLIC STAFF ALSO SUPPORT DUKE'S ASSUMPTIONS?

A. Yes. Witness Hinton specifically testifies that the Public Staff supports Duke's assumptions regarding expiring wholesale contracts.[8]

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[7] Public Staff Hinton Direct Testimony, at 9.
[8] *Id.*

Q. HAS DUKE AGREED WITH THE PUBLIC STAFF TO MORE CLEARLY ADDRESS EACH UTILITY'S FIRST YEAR OF PROJECTED AVOIDABLE CAPACITY NEED TO SERVE SYSTEM LOAD IN FUTURE IRPS.

A. Yes. As I committed in my direct testimony, Duke plans to include a Statement of Need section in future IRPs that identifies DEC's and DEP's first year of an avoidable need along with the supporting factors used to determine the avoidable need date. I agree with Witness Hinton's comments that the Companies' IRPs are used in several regulatory proceedings, and "a definitive statement of need, subject to approval by the Commission, would remove uncertainty surrounding the exact year of capacity need and provide a clearer standard for all parties to these various regulatory proceedings."[9]

Q. HAVE ANY INTERVENORS FILED TESTIMONY OPPOSING OR QUESTIONING DEC'S AND DEP'S IRPS' FIRST YEAR OF AVOIDABLE CAPACITY NEED FOR CALCULATING SCHEDULE PP RATES IN THIS PROCEEDING?

A. No. However, North Carolina Sustainable Energy Association ("NCSEA") Witnesses Dr. Ben Johnson and Carson Harkrader indirectly seem to take issue with the fact that Duke's IRPs assume that QFs are not presumptively recognized to establish a new legally enforceable obligation and assumed to immediately begin to deliver capacity to the utilities over a future new

[9] Public Staff Hinton Direct Testimony, at 10.

fixed term. More directly, however, these NCSEA witnesses advocate that existing QFs should continuously be paid for delivering capacity after their current PPA term expires on the assumption that the QF will enter into a new PPA for a new term.

Dr. Johnson testifies that "[existing] QFs are currently helping to meet the utilities' capacity needs, and there is no principled basis for ceasing to pay them for the capacity costs they are helping to avoid, once their contracts come up for renewal."[10] Witness Harkrader similarly argues that existing QFs should not be "stranded prior to the end of their useful life" and should continue to be paid for capacity immediately when their contracts come up for renewal.[11]

Q. IS NCSEA WITNESS JOHNSON'S POSITION THAT EXISTING QFS SHOULD BE PRESUMED TO CONTINUE TO DELIVER CAPACITY CONSISTENT WITH HIS PRIOR AFFIDAVIT TO THE COMMISSION IN THIS PROCEEDING?

A. No. In the earlier comment phase of this proceeding, Dr. Johnson filed an affidavit extensively discussing over multiple pages why it was unreasonable and inappropriate to assume for IRP purposes that a QF would commit to a new PPA at the conclusion of the term of its existing PPA. As discussed in the Duke Reply Comments[12], Dr. Johnson explains that QFs are "not captive to the utility" and suggested that "the Commission should

[10] NCSEA Johnson Direct Testimony, at 7-8.
[11] NCSEA Harkrader Direct Testimony, at 10.
[12] Duke Reply Comments, at 42-45.

acknowledge that QFs can potentially shut down, or sell their power elsewhere…" because a QF owner "can refuse to renew its fixed price contract, and sell – at least during peak hours – into the PJM market, or to another buyer."[13] Thus, Dr. Johnson has previously argued in this proceeding that it is "not appropriate" to assume existing QFs cannot be displaced by new QFs for purposes of determining the utility's future capacity needs.[14]

Q. HOW DO YOU RESPOND TO WITNESS JOHNSON'S TESTIMONY THAT DUKE'S APPROACH TO IDENTIFYING ITS NEXT CAPACITY NEED CONSTITUTES "SYSTEMATIC DISCRIMINATION" TO THE DISADVANTAGE OF QFS?

A. I disagree with Witness Johnson, and find his changing point of view in this proceeding about which QF may be disadvantaged telling. Duke's current and consistent position across numerous biennial IRP planning cycles has been to treat all wholesale purchase contracts the same and to recognize that a QF's legally enforceable commitment to provide energy and capacity extends only for the duration of its PPA. Duke's position is also fully consistent with FERC's implementing regulations, which provide QFs the right to establish a legally enforceable obligation committing to "the delivery of energy or capacity ***over a specified term*** . . ."[15] However, it clearly seems inconsistent with PURPA to presume that a commitment

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[13] NCSEA Initial Comments, at Attachment 2, ¶¶ 155-164.
[14] NCSEA Initial Comments, at Attachment 2, ¶¶ 163-164.
[15] 18 C.F.R. 292.304(d)(2) (emphasis added).

made for a specified contact term somehow obligates the QF to continue to deliver power to the utility after its contract term ends. As I emphasized in my direct testimony (and as previously recognized by Dr. Johnson), after the current PPA term expires, the QF has unfettered rights to make a business decision whether or not to establish a new LEO and contractually commit to deliver their full output, including capacity, to the utility.[16]

Importantly, the only discrimination that I see is in Dr. Johnson's proposal, which is clearly intended to advantage existing QFs over a new QF or other capacity resource. Duke is obligated to treat all existing and renewing QFs in a non-discriminatory fashion. Upon any QF making a new legally enforceable commitment to sell its output, Duke is then obligated to purchase the QF's output at its current avoided costs fixed at the time a LEO is established for the term of the contract.

Q. HOW DO YOU RESPOND TO DR. JOHNSON'S ARGUMENT THAT A QF MAY NEVER BE PAID FOR CAPACITY BECAUSE A UTILITY TYPICALLY COMMITS TO MEET ITS CAPACITY NEEDS THREE OR MORE YEARS INTO THE FUTURE?

A. Witness Johnson ignores that the DEP 2018 IRP showed its first avoidable need for capacity in year 2, or 2020, of the ten-year period 2019 through 2028. Consequently, his example of committing to new generation three years in advance is flawed. Furthermore, witness Johnson also ignores that the utility will often solicit requests for proposals ("RFPs") for new resource

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[16] Duke Snider Direct Testimony, at 12-13.

additions. DEP issued RFPs for new renewable resources as part of its CPRE program and also issued an RFP for dispatchable resources in 2018. Any resources that met the RFP requirements were eligible to bid into these RFPs, including expiring PPAs from PURPA or non-PURPA contracts. In summary, witness Johnson raises hypothetical concerns that do not align with the actual situation in North Carolina. Moreover, as Duke has committed to clearly address the timing of future capacity needs in future IRPs, QFs and other market participants will be able to review when the utility's next avoidable capacity need will arise and make business decisions regarding whether to pursue development of a QF to meet DEC's or DEP's next undesignated capacity need.

Q. DOES NORTH CAROLINA'S PURPA IMPLEMENTATION FRAMEWORK MAKE ANY DISTINCTION BETWEEN "EXISTING" QFS THAT ARE CURRENTLY SELLING TO THE UTILITY UNDER A FIXED TERM CONTRACT AND "NEW" QFS?

A. No. HB 589 makes no distinctions between the capacity purchase obligations from existing QFs and new QFs. The only plausible reading of HB 589's modifications to North Carolina's PURPA implementation framework is that the General Assembly has directed the Commission and Duke to treat all small power producer QFs on a consistent and non-discriminatory basis and to apply the avoided cost rate-setting framework prescribed in N.C. Gen. Stat. § 62-156 to all future purchase obligations established by Small Power Producer QFs. Any QF—pre-existing or new—that asserts a LEO to deliver energy and capacity to Duke has equal rights to meet undesignated future capacity needs, and N.C. Gen. Stat. § 62-156(b)(2) prescribes the methodology that Duke must use to establish its first year of capacity need and to fix avoided capacity rates both for all future purchase obligations in North Carolina.

Q. DO YOU AGREE WITH WITNESS JOHNSON THAT FAILING TO MAKE CONTINUAL CAPACITY PAYMENTS TO EXISTING QFs AFTER THEIR CONTRACT EXPIRY WOULD "UNDERMINE INVESTOR CONFIDENCE IN THE STATE LEGISLATIVE AND REGULATORY POLICY-MAKING APPARATUS"[17]?

A. No. Dr. Johnson suggests that failure by the Commission to adopt NCSEA's position regarding continuing to pay pre-existing QFS for capacity without interruption when they enter into a new PPA would "undermine investor confidence in the state legislative and regulatory policy-making apparatus."[18] However, it is actually Dr. Johnson's proposal that deviates from the clear policy direction in HB 589 which moves North Carolina toward a competitive process for attracting renewables rather than grandfathering existing QFs to prior capacity rates. Furthermore, Dr. Johnson does not mention that existing projects have already been financed by investors who are now enjoying QF payments at approximately twice competitively procured rates for renewables. HB 589 seeks to add

[17] NCSEA Johnson Direct Testimony, at 11.
[18] *Id.* at 11, 13.

renewable generation through a competitive procurement framework that protects consumers from further overpayments. It is clear that Witness Johnson is more concerned with QF investor returns than protecting customers.

Q. PLEASE ADDRESS DR. JOHNSON'S ARGUMENT THAT PRE-EXISTING QFS SHOULD BE PRESUMED TO CONTINUE TO DELIVER CAPACITY IN PERPETUITY BECAUSE SUCH TREATMENT WOULD BE SIMILAR TO THE COMPANIES' RIGHT TO RECOVER THEIR COSTS UNDER RATE BASE REGULATION.

A. Dr. Johnson argues that the utilities' customers should continue to make "full" capacity payments to existing QFs even after their PPAs expire, whether that capacity is needed to serve customers or not.[19] To do otherwise, Dr. Johnson opines, would be discriminatory because the Companies continue to receive full capacity cost recovery for all its generating units in rate base, regardless of whether or when the utility's most recent IRP demonstrates a need for capacity.[20] The Commission rejected this flawed comparison between QFs and utilities in the preceding Sub 148 avoided cost docket, and Dr, Johnson has provided no compelling reason why it should not do the same here.

In the 2016 Sub 148 proceeding, the Southern Alliance for Clean

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[19] *Id.* at 11.
[20] *Id.*

Energy ("SACE") witness testified that a 10-year term PPA is discriminatory, in violation of PURPA, because it results in QF solar projects being treated differently than utility projects with respect to recovery of costs.[21] The Commission disagreed, noting the numerous contrasts between QFs, which have no obligation to serve customers, and utilities that do, with respect to cost recovery. Those differences are significant with respect to the addition of capacity as well. First, the addition of new utility-owned generation is driven by integrated resource planning that is scrutinized by the Public Staff and other interested parties before the Commission. A specific utility plant addition is subject to review in CPCN proceedings, where the utility must usually demonstrate that the investment, if authorized, can be used to cost-effectively service customer energy and capacity needs. The Commission further noted that when a utility builds a plant and places it in rate base, it does not receive rate recovery based on forecasted avoided cost for energy and capacity like QFs, but instead earns a return on capital invested to meet its obligation to serve. In contrast, QFs have no limit on, and the Commission has no right to review, the amount of debt QFs may use for financing, the return on equity, or the overall rate of return. The longer depreciation lives for utility-owned assets are intended to lower the near-term rate impact for utility projects because lower annual depreciation costs are passed directly to the customers through a lower revenue requirement. In contrast, any such savings from

[21] *2016 Sub 148 Order*, at 35-36.

longer PPAs and lower financing costs are retained as profit by the QF developer and its investors and are not flowed through to customers. Because of these differences, I disagree with Dr. Johnson's assertion that our customers must continue to pay QFs for "must take" QF capacity that is not subject to Commission scrutiny or cost-of-service rate recovery whether or not that capacity is needed to serve customers.

Q. WHAT IS NCSEA WITNESS JOHNSON'S RECOMMENDATION REGARDING HOW THE COMMISSION SHOULD TREAT PRE-EXISTING QFS AS THEIR CURRENT PPAS APPROACH EXPIRY?

A. Dr. Johnson advocates allowing pre-existing QFs an opportunity to lock in, "at least 3 years before the current PPA expires," a new legally enforceable commitment to sell energy and capacity for a new contract term.[22] If a QF makes this "post-contract commitment" it would be entitled, under Witness Johnson's proposal, to "full avoided capacity payments without interruption for the full direction of the commitment period."[23] If the QF did not make the "post-contract commitment," Dr. Johnson suggests the QF would then retain "maximum flexibility" including its options as a QF to enter into a long-term contract or to elect an as-available energy rate at the time at the time of expiry.[24]

Q. DO YOU AGREE WITH DR. JOHNSON'S RECOMMENDATION?

[22] NCSEA Johnson Direct Testimony, at 15.
[23] *Id.*
[24] *Id.*

A. I do not. Dr. Johnson's proposal essentially would allow a pre-existing QF to establish a "placeholder" LEO three or more years in advance of its contract expiry to pre-emptively reserve capacity to be delivered at avoided cost rates that presumably will be established in the future closer in time to the period of delivery. Dr. Johnson does not address when avoided cost pricing would be determined or when the QF would actually execute a PPA under his proposal.

I have a number of concerns with this proposal. First, as I have discussed above, it would be inconsistent with North Carolina's implementation of PURPA to prospectively commit the Companies to continue to pay a QF for capacity "without interruption" if the Companies' IRPs project that such a need does not exist in a given year. Second, this policy seems to advantage pre-existing QFs over new QFs and other capacity resources without any meaningful indication when the QF making this "pre-commitment" will actually execute a PPA and make a binding commitment to deliver energy and capacity in the future. Allowing a QF to establish a LEO three years ahead of its contract expiry and to fix its pricing at the time of this "commitment" would also create significant risk of inaccurate avoided costs (potentially to the significant disadvantage of customers) and would be inconsistent with Duke's current policy allowing a QF to commit to a new PPA up to a year ahead of commencing the new delivery period. Duke Witness David Johnson provides additional detail regarding this policy. Establishing this long-dated pre-commitment also creates an increased risk that the QF may attempt to take advantage of changing market circumstances or other options to sell its power prior to the new delivery period commencing.

Q. **IS THERE ANY VALIDITY TO WITNESS HARKRADER'S CONCERN THAT QFS WILL BE "STRANDED" AFTER THE EXPIRY OF THEIR EXISTING PURPA PPA?**

A. No. I fail to see how any QF generator could be stranded, as the Companies will continue to be obligated to purchase all QFs' energy and capacity pursuant to North Carolina's continuing implementation of PURPA. Notably, QFs are merchant wholesale generators that have multiple other options to arrange to sell their output prior to expiry of their PURPA PPAs. As an established and interconnected renewable generator, the QF could elect to bid its future energy and capacity, beyond its current contract period, into any RFPs to competitively satisfy the utility's future capacity needs. Also, assuming the purchasing utility had a capacity need following expiry of the QF's PPA, nothing prevents that QF from bidding to serve that capacity need in advance of its PPA expiry. The QF could also elect to sell to other wholesale customers, such as municipalities or cooperatives that may have capacity and energy needs, as well as potential sustainability needs and goals. Finally, the QF could opt to participate in other utility-sponsored renewable programs such as the Companies' Green Source Advantage programs or Community Solar programs. In sum, the QF has ample opportunities as an established merchant generator to either continue to sell under PURPA or to attempt to sell its capacity and energy in advance of its contract expiry at the market prices prevailing at the time.

2. QF In-Service Date in Calculating Schedule PP Rates

Q. IS THE COMPANIES' IN-SERVICE DATE ASSUMPTION CONSISTENT WITH THEIR PAST STANDARD OFFERS IN PREVIOUS AVOIDED COST DOCKETS?

A. Yes. As I discussed in my direct testimony, the Companies' Schedule PP rates assume the in-service year is the year immediately following the filing of the new rate schedule. These rates are available for a traditional two-year period between biennial avoided cost proceedings. This well-established practice has been consistently applied in North Carolina avoided cost filings by both the Companies and Dominion Energy North Carolina ("DENC" and together with Duke, "the Utilities").

Q. PLEASE REVIEW NCSEA WITNESS JOHNSON'S RECOMMENDATION WITH RESPECT TO THE UTILITIES' CALCULATION OF THE BIENNIAL STANDARD OFFER RATE.

A. NCSEA Witness Johnson recommends that the Utilities abandon this well-established practice to instead shift the assumed in-service date for standard offer QFs to a future date – December 2021 instead of January 2019 – to enable these QFs to receive increased capacity revenues by assuming they would commence providing capacity during a later period when the capacity has a higher economic value to the Utilities.[25] Witness Johnson

[25] NCSEA Johnson Direct Testimony, at 17.

has supported his recommendation by generically suggesting that "delays" in the interconnection queue slow QFs from coming online.[26] Dr. Johnson has also suggested in the alternative that the Utilities could publish a "schedule of rates (or a formula)" that specified the applicable rate for all projects signing a PPA during the 2019-2020 period.[27] He states that the Utilities could then vary and publish these applicable rates, as frequently as monthly, during the biennial period after the filing of the Utilities' proposed avoided cost rates.[28]

Q. HAVE OTHER PARTIES IN THIS PROCEEDING ADDRESSED NCSEA'S RECOMMENDATION ON IN-SERVICE DATES?

A. NCSEA is the only party proposing to shift the in-service dates away from the Utilities' established practice. In addition to the Companies, both DENC and the Public Staff have opposed NCSEA's proposed modifications to the manner in which standard offer rates are calculated for the biennial period.

Q. WHAT WAS DENC'S POSITION ON WITNESS JOHNSON'S RECOMMENDED IN-SERVICE DATES?

A. In his direct testimony, DENC Witness Bruce E. Petrie raised concerns about the burdens Dr. Johnson's approach would impose on the Utilities

[26] *Id.* at 29.
[27] *Id.*
[28] *Id.*

and the uncertainties presented by multiple pricing schedules tied to various QF in-service dates.[29]

Q. WHAT WAS THE PUBLIC STAFF'S POSITION ON WITNESS JOHNSON'S RECOMMENDATION TO ASSUME A DELAYED IN-SERVICE DATE FOR QFS CONTRACTING UNDER THE STANDARD OFFER?

A. The Public Staff has disagreed with NCSEA's recommendation throughout this proceeding, concluding that the Utilities' consistent practice of calculating avoided costs for the biennial period assuming an in-service date in the year following the November 1 biennial filing date is reasonable and equitable to existing and new facilities.[30] In his direct testimony, Public Staff Witness Hinton also noted that the biennial filing of avoided cost rates provided a predictable and certain point for calculating avoided cost rates for standard offer contracts, and he cautioned that shifting the start of the standard offer contract away from the year immediately following the new rate schedule would likely result in a "mismatch" of payments to QFs and the utility's expected avoided energy and capacity costs.[31]

Q. HOW DO YOU RESPOND TO WITNESS JOHNSON'S RECOMMENDATIONS IN HIS DIRECT TESTIMONY?

A. First, I agree with the concerns and issues raised by DENC Witness Petrie and Public Staff Witness Hinton. Using a later "in-service" date and/or

[29] DENC Petrie Direct Testimony, at17-18.
[30] Public Staff Reply Comments, at 29 (filed March 27, 2019).
[31] Public Staff Hinton Direct Testimony, at 12.

requiring the Utilities to publish and update multiple pricing schedules would inject uncertainty into the process of small standard offer-eligible QFs signing PPAs with the Utilities. Next, as I have noted previously, with respect to small QFs 1 MW and less eligible for the Companies' Schedule PP, these QFs may proceed under the expedited Section 3 Fast Track and Supplemental Review interconnection process, which allows these smaller generators to be placed into service in less than a year, thereby negating Dr. Johnson's primary rationale for his initial recommendation.[32] Additionally, Dr. Johnson's recommendations only account for new QFs; existing QFs that elect to enter into a new fixed term PPA at the time their current PPA expires are already "in-service" and therefore potentially add another layer of complexity and inequity to administering Dr. Johnson's recommendations. Finally, as I noted in my direct testimony, a QF may always opt to establish a legally enforceable obligation ("LEO") closer to its in-service date or elect to pursue a negotiated PPA instead of selling under Schedule PP.

II. RATE DESIGN STIPULATION AND SEASONAL ALLOCATION

Q. PLEASE DESCRIBE THE COMPANIES' INITIALLY PROPOSED RATE DESIGN.

A. The Companies' initial proposal eliminated the pre-existing Option A and Option B rate structures and developed updated, more granular rate designs to better recognize the value of QF energy and capacity. The design also

[32] Duke Snider Direct Testimony, at 16-17.

sought to balance a more granular design with administrative considerations to aid QFs in responding to the Schedule PP tariffs' price signals. The revised design was developed in response to the Commission's *2016 Sub 148 Order* directing the Companies to consider "a rate scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during the critical peak demand periods."[33]

Q. HOW WAS THE COMPANIES' PROPOSED DESIGN MODIFIED IN RESPONSE TO COMMENTS FROM THE PUBLIC STAFF AND INTERVENORS?

A. The Public Staff and other parties suggested that additional granularity, beyond what the Companies had initially proposed was "appropriate and beneficial to North Carolina ratepayers."[34] Further discussions led to a Stipulation between the Companies and Public Staff which adopts a modified version of the Public Staff's three-step rate design approach that sets forth the factors that are important to the determination of the Companies' rate design. Applying this methodology, energy and capacity periods are identified that best reflect the Companies' individual avoided cost based upon seasonal and time-of-day characteristics. The Companies filed the Stipulation with the Commission on April 18, 2019 ("Rate Design

[33] *2016 Sub 148 Order*, at 56.
[34] Public Staff Initial Comments, at 48, 54.

Stipulation") presenting the updated, more granular rate design agreed to between Duke and the Public Staff.

Q. PLEASE ADDRESS SACE WITNESS WILSON'S CLAIM THAT THE STIPULATED AVOIDED CAPACITY RATE DESIGN SHOULD NOT FOCUS ON A RELATIVELY FEW MONTHS OF THE YEAR AND HOURS OF THE DAY.

A. The Stipulated Rate Design adheres to the Commission's *2016 Sub 148 Order* by paying higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power and is reflective of the utility's costs during the critical peak demand periods. The design is also consistent with the *2018 Scheduling Order* which similarly directed the Companies to "file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer peak periods, with more granularity than the current Option A and Option B rate schedules."[35] Thus, the new rate design appropriately follows these orders by paying QFs higher capacity payments only in hours with high loss of load risk. The benefit of this design is that QFs will be provided improved price signals that are better aligned with customer generation needs.

The Companies were cognizant of SACE Witness James F. Wilson's concern with defining the rate design too narrowly as conditions change over the duration of the contract, since it could lead to inaccurate

[35] *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing,* Docket No. E-100, Sub 158 (June 26, 2018) ("*2018 Scheduling Order*").

price signals. This was a key consideration in discussions with the Public Staff to arrive at the rate design methodology presented in the Rate Design Stipulation, which the Companies used to develop the stipulated rate design proposed in this proceeding. The Companies believe that the stipulated rate design fairly balances these considerations in a manner that appropriately reflects cost causation and offers QFs the opportunity to adjust their production hours to maximize their financial benefit, in addition to being administratively manageable from a metering and billing perspective. The rate design presented in the Rate Design Stipulation also conforms with the fundamental indifference or "but for" principle of PURPA ensuring customers are not paying more than the actual costs avoided by the utility.

Q. DID NCSEA WITNESS JOHNSON SUPPORT THE PROPOSED RATE DESIGN?

A. No. While Witness Johnson commented that the Stipulated Rate Design was an improvement over the Companies' initial proposal with respect to seasonal and hourly patterns, he recommended that the design could go further by calculating different rates for each hour of the month.[36]

Q. DO THE COMPANIES SUPPORT OFFERING 24 DIFFERENT RATES DURING EACH DAY OF EACH MONTH?

A. No. A design offering 24 different hourly rates each day would tend to lock in price differences and price relationships between the hours in a manner that would likely not coincide with actual real-time system conditions. On

[36] NCSEA Johnson Direct Testimony, at 5.

a real-time basis there is often a considerable difference in the cost of serving load each hour based upon the day of the week, the influence of actual hourly weather conditions and corresponding customer usage characteristics. The influence of these factors would be obscured with a 24-hour monthly design as advocated for by Witness Johnson. The Companies' approach of offering narrowly defined ranges of hours in distinct price groups better aligns prices with periods where higher cost is expected. The rate design also offers a consistent price signal that is intended to incent and maximize generation at times when generation is of most value to customers, while simultaneously balancing the fact that the design applies to a forward-looking, ten-year fixed rate. Last, offering 24 rates also unnecessarily increases billing complication, thereby increasing the risk of billing errors.

Q. IS INCLUSION OF REAL-TIME PRICING ("RTP") TO BETTER REFLECT COST VARIATIONS BASED UPON WEATHER FLUCTUATIONS AS ADVOCATED BY NCSEA WITNESS JOHNSON APPROPRIATE?

A. No. While the Companies generally agree with Witness Johnson that real-time pricing rates for QFs could better align the Companies' actual avoided costs to QF payments, Witness Johnson's proposal appears to argue for RTP rates during times when costs to serve are high, but a guaranteed forecasted average cost rate during all other hours, including hours when the cost to serve is lower than the average avoided cost rate.[37] This approach would inappropriately result in increased payments to QFs, above the forecasted marginal cost set in the standard offer rates. Accordingly, this approach would also seem to be inconsistent with FERC's general implementation of PURPA, which provides that a QF may elect to commit to deliver its power at the utility's avoided cost either calculated at the time of delivery ***or*** calculated at the time the QF makes its legally enforceable commitment to deliver energy and capacity.[38] Dr. Johnson notably does not support a true RTP rate similar to Dominion's LMP tariff during all hours.[39]

The Companies believe that the pricing periods reflected in the Stipulation are appropriately granular at this time and should not be expanded to include RTP features. Given sufficient QF interest, the Companies would be agreeable to investigate development of RTP periods for standard offer QFs that do not require the financial assurance of a fixed rate and instead are willing to accept rates calculated at the time of delivery based upon the Companies' actual hourly marginal cost of energy. However, as previously mentioned, the QF has the choice of either projected long-term avoided cost rates or rates at the time of delivery, but not a single rate design that strives to accomplish both objectives at the same time.

[37] NCSEA Johnson Direct Testimony, at 33-34.
[38] *See* 18 C.F.R. § 292.304(d)(2).
[39] NCSEA Johnson Direct Testimony, at 36-37.

Q. SHOULD THE COMPANIES CONSIDER OFFERING GEOGRAPHICALLY DIFFERENTIATED AVOIDED COST RATES AS ADVOCATED BY NCSEA WITNESS JOHNSON?

A. No. Witness Johnson provides little support for his recommendation[40] to require the Utilities to develop detailed plans for how they would go about implementing geographically granular rates. Additionally, this recommendation is neither appropriate nor cost beneficial when one considers the limits of the PURPA standard offer framework in North Carolina under HB 589. Moreover, as the Public Staff and the Commission found in the recent interconnection docket, distribution level hosting capacity maps provide little benefit relative to their anticipated cost and due to the recent shift towards larger, transmission-connected projects in North Carolina.[41] Geographic pricing is also problematic because the Companies have the capability to reconfigure the distribution grid to shift load and generation across distribution circuits to achieve a better balance. As this shift occurs, it will alter the line loading and thereby change the cost/benefit of having generation on a specific circuit. The use of non-geographically differentiated standard offer pricing is easier to administer and offers a fair rate to small QF generators eligible for the standard offer. Accordingly, NCSEA's advocacy for more geographic price signals through development of hosting capacity maps is inappropriate and should therefore be rejected.

[40] *Id.* at 6.
[41] *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony*, at 58, Docket No. E-100 Sub 101 (June 14, 2019).

Q. DO THE COMPANIES SUPPORT WITNESS JOHNSON'S PROPOSAL[42] THAT THE UTILITIES BE REQUIRED TO OFFER A PLAN 6 MONTHS PRIOR TO THE NEXT BIENNIAL PROCEEDING TO ADDRESS GEOGRAPHIC COST DIFFERENCES AND RTP DESIGNS?

A. No. The Companies do not believe that further study of geographic pricing and RTP price options will lead to more effective avoided cost rate structures and therefore should not be required at this time. The Companies believe that the continued application of the rate design methodology included in the Rate Design Stipulation with the Public Staff adequately aligns avoided cost and rates and is the appropriate basis for setting standard offer rates.

In sum, the Companies believe the rate design presented in the Stipulation complies with the Commission's *2016 Sub 148 Order* and *2018 Scheduling Order* and provides more granular price signals that are reflective of each utility's actual avoided energy and production cost. The Companies continue to look at ways to provide fair, reasonable and accurate price signals to better recognize the value of QF energy and capacity, but a requirement to conduct extensive studies is unnecessary.

Q. PLEASE DESCRIBE THE SEASONAL CAPACITY ALLOCATION SUPPORTED BY THE COMPANIES AND AGREED TO BY THE PUBLIC STAFF IN THE RATE DESIGN STIPULATION.

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[42] NCSEA Johnson Direct Testimony, at 37.

A. As described in my direct testimony and the Stipulation, approximately 100% of DEP's loss of load risk occurs in the winter and approximately 90% of DEC's loss of load risk occurs in the winter. Thus, DEP's new rates pay all of its annual capacity value in the winter, and DEC's new rates pay 90% of its annual capacity value in the winter and 10% in the summer.

Q. PLEASE RESPOND TO THE PUBLIC STAFF'S POSITION ON THE COMPANIES' PROPOSED SEASONAL CAPACITY ALLOCATION.

A. Public Staff Witness Jeffrey T. Thomas testifies that the Public Staff largely agreed with Duke's proposed capacity payment hours and seasonal allocation and did not propose any significant changes to the capacity rate design.[43] The Public Staff stated that to prevent overpayment to QFs for capacity that is not needed, it is most appropriate to pay capacity payments only during hours where there is a loss of load risk.[44] The Public Staff further noted that utility-owned capacity is only deferred when QFs can provide capacity during the winter hours when capacity is needed the most – specifically, the early morning hours.[45] Finally, Public Staff Witness Thomas noted that Duke's use of the loss of load expectation ("LOLE") metric is reasonable and protects ratepayers from overpaying for QF

[43] Public Staff Thomas Direct Testimony, at 36.
[44] *Id.*
[45] *Id.* at 36-37.

capacity and concluded that the proposed rate design sends the appropriate price signals to QFs.[46]

Q. DOES NCSEA WITNESS JOHNSON AGREE WITH THE COMPANIES' SEASONAL CAPACITY ALLOCATION, AS SUPPORTED IN THE RATE DESIGN STIPULATION?

A. No. NCSEA Witness Johnson argues that an assessment of historic loads does not support a seasonal allocation heavily weighted to the winter. Dr. Johnson comments extensively regarding his assessment of historic load data and notes that most hours with usage near the annual peak have historically occurred more often during the summer and thus concludes that common sense and economic theory both suggest that a large share of capacity costs should be allocated to the summer.[47]

Q. IN GENERAL, ARE NCSEA'S CRITICISMS OF THE COMPANIES' PROPOSED SEASONAL CAPACITY ALLOCATION SIMILAR TO THEIR CRITICISMS OF THE COMPANIES' COMMISSION-APPROVED SUB 148 SEASONAL CAPACITY ALLOCATION?

A. Yes. NCSEA Witness Johnson continues to criticize the Companies' consistent approach to seasonal allocation based on reviews of historic DEC and DEP load conditions without consideration of changes in those load conditions over time. This is essentially the same argument that he made in

[46] Public Staff Thomas Direct Testimony, at 37.
[47] NCSEA Johnson Direct Testimony, at 6-7, 40-44.

the 2016 Sub 148 proceeding. Importantly, NCSEA also continues to ignore the impact of must take solar generation on loss of load risk and the resulting seasonal allocations for capacity.

Q. WAS THE COMMISSION PERSUADED BY NCSEA WITNESS JOHNSON'S ARGUMENTS IN THE 2016 SUB 148 CASE?

A. No. The Commission appropriately recognized that avoided cost rates are set for a ten-year forward-looking period, and, as such, that the facts and circumstances over that future time period should be utilized to allocate capacity payments rather than by relying on a review of historic loads. Specifically, the Commission summarized Witness Johnson's testimony:

> "NCSEA witness Johnson testified that he had reviewed DEC's and DEP's hourly load data from 2006-2015 and determined that 86.5% of the most extreme system peaks occurred from June through September, while the remaining 13.5% occurred in the winter months of December through February. He concluded that rather than shift seasonal allocation toward winter, these data support a stronger allocation toward summer.[48]

The Commission, however, was "not persuaded by Witness Johnson's argument that historic summer peak load data does not support Duke's seasonal weightings," instead finding and concluding that "Witness Snider's testimony that high penetrations of solar have a significant impact on summer versus winter loads net of solar contributions and his testimony

[48] *2016 Sub 148 Order*, at 59.

regarding the associated impact on reserves and loss of load risk sufficiently address the concerns expressed by Witness Johnson in his testimony."[49]

Q. WHY IS DR. JOHNSON'S REASONING THAT HE RELIES UPON TO OPPOSE THE COMPANIES' SEASONAL ALLOCATION OF CAPACITY FLAWED?

A. Dr. Johnson's review of historic summer periods again fails to account for solar impacts and changing peak demand conditions and instead incorrectly focuses only on the number of historic high gross load hours for DEC and DEP dating back to 2006. Notably, and consistent with Duke's approach in the 2016 Sub 148 proceeding, the Companies are again designing rates that apply to QFs over a ten-year forward-looking period, and not a historic period. Importantly, this future period has a significant level of solar on the grid relative to the historic period relied upon by Dr. Johnson.

With respect to load, the Companies have also seen significant cold weather load response over recent years during times of winter peak conditions. Dr. Johnson's review period notably did not include the year 2018 in which North Carolina had sustained cold weather for an entire week in January resulting in sustained winter high load conditions in excess of summer conditions. In contrast to Witness Johnson's arguments, the Public Staff, in its review of DEP's 2018 IRP expressed concerns that the Companies may be underestimating its winter peak demand forecast.[50]

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[49] *Id.* at 61.
[50] Public Staff Initial Comments, at 12.

When taken in total, this highlights the necessity to view loss of load risk and resulting seasonal allocation based on forward looking load conditions that are based on "net system load" that accounts for the impact of solar generation.

Q. **PLEASE ELABORATE ON WHAT YOU MEAN BY "NET SYSTEM LOAD."**

A. It is uncontroverted that the Companies have experienced significant penetration of solar resources in recent years with significantly more solar resources projected to be interconnected in the coming years. This must-take solar output essentially serves to reduce the Companies' total load during daylight periods with varying output dependent on cloud cover or irradiance. This variable output during daylight hours results in the "net system load" that conventional resources will be required to serve. Notably, solar resources contribute significantly more during summer high load periods that occur in the afternoon and evening hours as compared to winter high load periods that typically occur in the early morning and late evening hours when solar output is low or not available at all. Thus, contrary to Dr. Johnson's arguments, assessment of historic loads without consideration of the impact of current and projected levels of must-take solar output does not provide meaningful insights into the appropriate seasonal allocation weightings.

Q. **WITNESS JOHNSON ALSO REFERENCES OTHER SURROUNDING JURISDICTIONS THAT ARE "SUMMER**

PEAKING" AS EVIDENCE FOR HIS CLAIM TO ALLOCATE MORE CAPACITY VALUE TO THE SUMMER.[51] HOW DO YOU RESPOND TO THIS ASSERTION?

A. Dr. Johnson selectively points out that surrounding utilities such as TVA, "the PJM system", and Georgia Power Company have summer peaks as reason to question seasonal allocation on the DEC and DEP systems. He notably does not mention South Carolina Electric and Gas, which is now projecting to switch to winter peaking and who also had to shed load during January 2014 a polar vortex event due to insufficient winter capacity.[52] In addition, Dr. Johnson also fails to mention regional differences that impact seasonal LOLE and resulting seasonal allocations. Importantly, he also fails to recognize that North Carolina has significantly more installed solar and more planned solar than any other jurisdiction he mentions. As previously explained, this factor has a significant impact on seasonal loss of load risk as the system responds to its net load obligation.

Dr. Johnson also does not mention differences in wind penetration between PJM and North Carolina which also significantly influence seasonal LOLE calculations. Dr. Johnson further states that "...uncommonly cold weather rarely lasts for more than a few hours."[53] This simply is not the case in North Carolina. Polar vortex events have

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[51] NCSEA Johnson Direct Testimony, at 37-38.
[52] South Carolina Electric & Gas Company's 2019 Integrated Resource Plan, at 3-4, 47-48, SC PSC Docket No. 2019-9-E (filed Feb. 8, 2019).
[53] NCSEA Johnson Direct Testimony, at 38.

occurred multiple times in recent years where the system has had to sustain days, not hours, of very cold weather with daily loads well in excess of summer loads. He goes on to suggest that residences rely on electricity for cooling, but many rely on natural gas for heating.[54] However, Dr. Johnson fails to recognize that the Southeastern United States is the only region of the country in which the majority of residential heating is done with electric heating as opposed to gas or oil heating. As a result, when evaluating seasonal loss of load risk, any comparison to PJM has little probative value.

Q. HOW WERE THE COMPANIES' SEASONAL CAPACITY ALLOCATIONS DEVELOPED?

A. The seasonal capacity allocations were based on the probabilistic LOLE study results from the Solar Capacity Value Study conducted by Astrapé Consulting, LLC ("Astrapé") in 2018.

Q. WHY DO YOU BELIEVE A COMPREHENSIVE PROBABILISTIC ANALYSIS, AS USED IN DEVELOPING THE SOLAR CAPACITY VALUE STUDY, IS MORE APPROPRIATE FOR DETERMINING THE SEASONAL CAPACITY ALLOCATION THAN A HISTORIC LOAD ANALYSIS OR RELYING ON OTHER UTILITIES' EXPERIENCE, AS RECOMMENDED BY DR. JOHNSON[55]?

A. Astrapé modeled thousands of iterations in its Strategic Energy Risk Valuation Model ("SERVM") to capture combinations of load uncertainty

[54] *Id.*
[55] NCSEA Johnson Direct Testimony, at 7.

due to extreme weather, economic load growth uncertainty and unit outages, and to capture the impacts of load and generator outage diversity. To capture load uncertainty, the study incorporated 36 years of historic weather data to develop synthetic load shapes for projecting what loads would be in the future study year if historic weather repeated itself for each of the 36 years. The study also modeled hourly profiles for solar output based on National Renewable Energy Laboratory or "NREL" irradiance data for the 36 weather years in order to capture projected solar output consistent with the weather data. Thus, the LOLE study results quantified through the Solar Capacity Value Study capture not only load variations but also expected solar output consistent with their output profiles, as well as many other variables as I previously noted. This level of modeling is necessary to adequately capture the loss of load risk throughout the year. While the simplistic assessment of historic load data in isolation, as conducted by Dr. Johnson may be an interesting exercise, it is wholly inadequate for assessing loss of load risk and defining the appropriate seasonal capacity allocation on a forward looking basis.

Q. PLEASE ADDRESS SACE WITNESS WILSON'S TESTIMONY REGARDING SEASONAL ALLOCATION OF CAPACITY VALUE?

A. Witness Wilson continues the same critiques of the study methodology used in the Companies' 2016 Resource Adequacy studies and specifically recommends that the Commission reject the Companies' seasonal allocation factors.[56] The Companies have previously fully responded to these recommendations in reply comments in this proceeding and in the Sub 157 proceeding.[57]

Q. DID THE COMMISSION'S *2016 SUB 148 ORDER* ALSO ADDRESS THE COMPANIES' 2016 RESOURCE ADEQUACY STUDY SUPPORTING THE SEASONAL CAPACITY ALLOCATION, WHICH SACE CONTINUES TO ARGUE AGAINST?

A. Yes. The Commission found at page 60 of the *2016 Sub 148 Order* that it was appropriate to rely on the Companies' 2016 Resource Adequacy study for purposes of seasonal allocation of capacity payments and expressly stated that the Commission "agrees that Duke's winter capacity planning is distinct from winter peaking."

Q. IS WITNESS WILSON'S RECOMMENDATION TO REJECT THE RATE DESIGN STIPULATION'S SEASONAL ALLOCATION FACTORS APPROPRIATE[58]?

A. No. The new seasonal allocation is more heavily weighted to winter based on the impact of summer versus winter loss of load risk. As presented in the Companies' 2018 IRPs, 100% of DEP's loss of load risk occurs in the winter, and approximately 90% of DEC's loss of load risk occurs in the winter. The use of these same values as allocation factors to represent the

[56] SACE Wilson Direct Testimony, at
[57] DEC and DEP Reply Comments, at 58-63; *see also* DEC and DEP Reply Comments, at 42-50, Docket No. E-100, Sub 157 (May 20, 2019).
[58] SACE Wilson Direct Testimony, at 11.

seasonal capacity benefit provided by a QF is a fair and reasonable method and properly aligns with cost causation principles.

The Companies also note that the Public Staff has agreed to these assumptions for purposes of the current avoided cost proceeding, and Duke plans to work with the Public Staff to update all inputs and modeling assumptions and to complete new resource adequacy studies in support of the 2020 biennial IRP filings.

Q. DO YOU HAVE ANY OTHER SUPPORT FOR THE COMPANIES' PROBABILISTIC APPROACH FOR VALUING SOLAR AND DETERMINING THE SEASONAL CAPACITY ALLOCATION?

A. Yes, the importance of probabilistic models to assess the impact of intermittent solar resources is generally recognized across the electric utility industry, as noted by a recent North American Electric Reliability Corporation ("NERC") Report on resource adequacy:

> "There is a recognized need to support probability-based resource adequacy assessment resulting from the changing resource mix with significant increases in variable and energy-limited resources (intermittent in nature), changes in net demand profiles resulting in the shifting of the hour of the peak demand, and other factors can have an effect on resource adequacy."[59]

As noted by NERC, probabilistic assessments are needed to appropriately model intermittent resources and capture the associated impacts on peak demands, shifting of peak demands and loss of load risk. A simple

[59] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures Technical Reference Report at 6 (April, 2018), *accessible at:* https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf (last visited July 3, 2019).

evaluation of historic loads in isolation, as conducted by Dr. Johnson, does not capture the impacts on LOLE associated with must-take solar output or other reliability risks.

Q. REGARDING THE IDENTIFICATION OF CAPACITY PAYMENT MONTHS, DR. JOHNSON CRITICIZES DUKE'S DECISION TO ALLOCATE CAPACITY ONLY TO JULY AND AUGUST AND TO THE EXCLUSION OF OTHER SUMMER MONTHS.[60] HE ALSO MAKES SIMILAR CRITIQUES REGARDING THE ALLOCATION OF CAPACITY TO MARCH.[61] HOW DO YOU RESPOND?

A. As an initial matter, and as previously discussed, Dr. Johnson's assessment appears to be based primarily on his evaluation of historic load data in isolation which fails to recognize many other factors influencing loss of load risk and system reliability in the future. As I previously noted, the LOLE study results capture not only historic loads, but also solar output that would have been realized when modeling historic load profiles, as well as many other variables including unit outages, load uncertainty and diversity of load and unit outages. As I noted, the Companies relied upon hourly LOLE data to define the seasonal allocation as well as the capacity payment months and hours. The LOLE data shows that essentially no loss of load risk occurs for DEC and DEP in June and September. The data also shows that a small amount of LOLE occurs during March.

[60] NCSEA Johnson Direct Testimony, at 40.
[61] *Id.* at 44.

Q. DID INTERVENORS PRESENT ANY NEW EVIDENCE TO SUGGEST THAT THE SEASONAL ALLOCATIONS INCLUDED IN THE STIPULATION AGREEMENT WITH THE PUBLIC STAFF ARE FLAWED?

A. No. Dr. Johnson and Mr. Wilson continue to criticize the Companies' demand-side management ("DSM") program deployment efforts and suggest that the winter DSM portfolio can be easily brought up to the same level as the summer DSM portfolio and thus minimize the winter loss of load risk. Specifically, Dr. Johnson states "it would be cost effective and appropriate to dramatically increase efforts to incentivize customers to reduce their load during winter peak hours."[62] Similarly, Mr. Wilson states that "If instead the winter demand response is brought up to the summer level (and everything else remains the same), this eliminates load loss in the winter in the 2016 Resource Adequacy Study to the point where there are now more summer than winter hours with load loss."[63]

The Companies commented on this issue extensively in the prior Duke Reply Comments filed in this proceeding as well as in reply comments provided in pending IRP docket.[64] Although the Companies agree with NCSEA and SACE that winter DSM programs are a reasonable tool for reducing winter peak demand, when available and cost-effective, the levels

[62] NCSEA Johnson Direct Testimony, at 46.
[63] SACE Wilson Direct Testimony, at 19.
[64] Duke Reply Comments, at 63-66; *see also* DEC and DEP Reply Comments, at 50-52, Docket No. E-100, Sub 157 (May 20, 2019).

of reduction proposed by NCSEA and SACE are extremely optimistic and not reasonably achievable in the timeframe proposed, if at all. The Companies also note their plans to implement new winter DSM programs as proposed in the 2018 IRP, and continue to work toward implementation of those programs. However, the extreme amounts of DSM deployment that these intervenors anticipate to be cost effective and reasonably achievable are unsupported and cannot prudently be included in the IRP forecast.

Q. WITNESS JOHNSON ALSO SUGGESTS THAT DUKE'S SEASONAL ALLOCATION IS INCONSISTENT WITH PURPA[65], SUGGESTING THAT QFS ARE SUPPOSED TO BE FULLY COMPENSATED FOR THE CAPACITY COSTS THEY ENABLE UTILITIES TO AVOID. DO YOU AGREE?

A. While I agree that PURPA provides that utilities, and ultimately customers, should compensate QFs for future capacity costs that QFs enable the utility to avoid, I do not agree that Duke's IRP planning methodology and approach to recognizing future capacity needs based upon future loss of load expectation is in any way inconsistent these general PURPA principles. Duke's IRP is technology agnostic in identifying its future capacity needs and the avoided capacity rates being designed in this proceeding are not being developed for one particular QF technology or another. For example, as recognized by Public Staff Witness Thomas, the current seasonal

[65] NCSEA Johnson Direct Testimony, at 48.

allocation and capacity rate design allows QFs with storage to receive significant capacity payments for their ability to meet true system capacity needs.[66] The fact that stand-alone solar QFs cannot provide capacity in the winter when the Companies' LOLE risk occurs is reflective of the real-world limitations of non-dispatchable solar QFs' ability to provide capacity, and in no way supports Witness Johnson's suggestion that solar QFs are not being fully compensated for the capacity value they provide.

Q. IS DUKE'S SEASONAL ALLOCATION METHODOLOGY ALSO CONSISTENT WITH NORTH CAROLINA'S IMPLEMENTATION OF PURPA?

A. Yes. Duke's IRP methodology for evaluating the Companies' future capacity needs and, specifically, the seasonal allocation of that capacity in fixing avoided capacity rates is fully consistent with North Carolina's implementation of PURPA pursuant to HB 589. As I introduced earlier in my testimony, Subsection (b)(3) of N.C. Gen. Stat. § 62-156 provides that:

> A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to G.S. 62-110.1(c) has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power . . .

Duke has reasonably and appropriately identified each utility's first projected year of capacity need required to serve system load and has designed avoided capacity rates that satisfy the Companies' projected need

[66] Public Staff Thomas Direct Testimony, at 38-40.

for future capacity beginning in the year of first projected need. QFs capable of meeting the need based upon their "availability and reliability of power" are paid for the capacity value they provided when needed by Duke's system, which is fully consistent with PURPA's purpose and intent.

Q. CAN SEASONAL ALLOCATION CHANGE OVER TIME?

A. Yes. The seasonal capacity allocation may change over time due to changes in customer mix, customer energy usage, and changes to the summer and winter resource mix including the continued addition of solar resources, the addition of battery storage capability, longer-term potential wind resources, additional DSM or other changes impacting the balance of summer versus winter resources. As required by North Carolina's implementation of PURPA, the Companies will update their standard offer QF rates biennially and make adjustments as appropriate to reflect changes in inputs, system resource mix and other assumptions that may impact the seasonal allocation of DEC's and DEP's respective capacity needs in the future. Based upon the Companies best projections of future system needs, however, the Companies support the seasonal capacity allocations underlying the avoided capacity rates presented in the Rate Design Stipulation agreed to with the Public Staff.

III. ANCILLARY SERVICES COST

1. Quantification of Ancillary Services Cost of Integrating QF Solar

Q. WHAT ARE YOUR GENERAL OBSERVATIONS REGARDING INTERVENOR TESTIMONY IN RESPONSE TO THE ASTRAPÉ

ANCILLARY SERVICES STUDY AND THE PROPOSED INTEGRATION SERVICES CHARGE?

A. I have three general observations. First, there is no dispute amongst the expert witnesses that the integration of uncontrolled, intermittent and variable solar generators is causing the Companies to incur increased ancillary services cost. The Public Staff has recognized this to be the case since its initial comments and has now agreed to Duke's quantification of these costs through the Solar Integration Services Charge Stipulation ("SISC Stipulation") filed with the Commission on May 21, 2019. SACE Witness Brendan Kirby continues to challenge certain technical aspects of the Solar Ancillary Service Study conducted by Astrapé Consulting ("Astrapé Study") and now advocates for a different methodology used by Idaho Power Company, which he believes would more accurately quantify Duke's integration costs. Thus, while Mr. Kirby may dispute Astrapé's quantification of the Companies' ancillary services costs, he does not dispute the fact that Duke is incurring integration costs associated with growing solar penetrations on the Companies' systems. Duke Witness Nick Wintermantel of Astrapé Consulting addresses Mr. Kirby's technical concerns with the Astrapé Study.

NCSEA's witnesses continue to oppose the Integration Services Charge. However, NCSEA Witness R. Thomas Beach does not suggest that Duke is not incurring integration costs. Instead, Mr. Beach essentially argues that Duke should be doing more to operationally manage these increased ancillary services costs caused by intermittent solar generation and should also consider new wholesale market structures such as an energy imbalance market ("EIM") to more efficiently purchase the ancillaries services required. I respond to these recommendations below, but, again, it is important to recognize that no expert witnesses in this proceeding dispute that real integration costs are being incurred and—absent an appropriate charge being established—such costs will continue to be recovered from customers.

My second observation is that the SISC Stipulation agreed to between Duke and the Public Staff should be given significant consideration and weight by the Commission. I concur with Public Staff Witness Thomas' testimony explaining that Duke, Astrapé, and the Public Staff have engaged in a number of beneficial technical discussions regarding the Public Staff's originally-identified concerns presented in prior comments in this proceeding. Through these discussions, including Duke providing additional analysis and supplemental information to the Public Staff, the Public Staff has now determined that the Astrapé Study reasonably quantifies Duke's ancillary services costs and is in general alignment with other similar studies conducted across the country.[67] Witness Thomas also agrees that the Integration Services Charge appropriately assigns these costs on an average basis to all uncontrolled solar generators that impose the

[67] Public Staff Thomas Direct Testimony, at 9.

additional costs on the Companies' systems.[68] The SISC Stipulation balances a number of considerations, and attempts to reasonably address the concerns of the solar industry through the "controlled solar generator" provision for innovative QFs (which I discuss further below) as well as the proposed cap on the Integration Services Charge, which limits solar QF generators' exposure to potential changes to the Integration Services Charge in the future as Duke continues to evaluate its integration costs in future biennial avoided cost proceedings.

My third observation is that NCSEA Witnesses Carson Harkrader's and Beach's largely policy-based testimony opposing the Integration Services Charge and advocacy for the Commission to pursue an "ancillary services market" or EIM fails to recognize the limited purpose of this biennial avoided cost proceeding, which is to quantify Duke's actually-avoidable energy and capacity costs that solar QFs can provide. As I explained in my direct testimony, the proposed Integration Services Charge is directly responsive to the Commission's directive in the *2016 Sub 148 Order* to recognize the "marked differences" in the costs avoided (or additional costs created) by QFs delivering intermittent, non-dispatchable power.[69] The Integration Services Charge is designed to quantify these increased costs as additional solar generators are added to the Companies' systems. Ms. Harkrader's recommendation to "reward the interconnection

[68] *Id.* at 17-18.
[69] Duke Snider Direct Testimony, at 33-34.

of QFs that provide ancillary services" would effectively promote paying solar QF generators to solve a problem that their intermittent, non-dispatchable power is creating.[70]

Q. PLEASE RESPOND TO NCSEA'S TESTIMONY THAT OFFSETTING "BENEFITS" OF INTEGRATING QF SOLAR SHOULD ALSO HAVE BEEN QUANTIFIED AND THAT "THESE BENEFITS WILL MORE THAN OFFSET ANY INTEGRATION COSTS."[71]

A. NCSEA's witnesses oppose the Integration Services Charge not on the technical merits of the Astrapé Study or by attempting to refute that Duke is, in fact, incurring the increased ancillary services costs to integrate solar QF generators. Instead, NCSEA Witnesses Harkrader and Beach allege that the charge should be rejected because the Commission also needs to consider the "benefits" of integrating distributed solar generation.

Ms. Harkrader notably makes this "consider the benefits" critique no less than ten times in her testimony without articulating with any specificity which purported benefits Duke allegedly failed to consider.[72] At page 14 of her testimony, she comes closest by suggesting that my direct testimony "ignore[s] solar's role in reducing the summer system wide peak" and advocates that the Commission should "adopt pricing for ancillary services" in order to promote innovation through the addition of advanced

[70] NCSEA Harkrader Direct Testimony, at 16.
[71] NCSEA Beach Direct Testimony, at 7-8.
[72] NCSEA Harkrader Direct Testimony, at 9, 11, 13, 14, 16, 17, 20.

technologies such as battery storage that can provide ancillary services to the grid. As an initial matter, Ms. Harkrader is incorrect that Duke has ignored solar's role in reducing summer peaks in either quantifying the Integration Services Charge or in designing avoided cost rates. As I highlighted earlier in this testimony, the contribution of installed solar to meeting the Companies' summer capacity needs has accurately been reflected in the Companies' updated avoided capacity rate design, including allocating future capacity needs to the winter season. And while the integration of battery storage systems can potentially mitigate the increased ancillary services costs caused by a solar QF's uncontrolled operations, the Commission must not lose sight of the fact that any "benefit" to the grid is limited to eliminating the intermittency and volatility caused by the solar QF generator's operations which are creating these incremental costs in the first place. Later in my testimony I address how the SISC Stipulation enables solar QFs to commit to reduce or eliminate these increased ancillary services costs and to receive the benefit of their advanced operations by avoiding the Integration Services Charge.

NCSEA Witness Beach identifies two purported system cost reductions associated with integrating solar energy that he recommends should have been recognized as offsetting the increased generation ancillary services costs in the Astrapé Study: (1) lower overall wholesale market prices due to integration of zero-variable cost renewables; and (2) avoided transmission and distribution capacity cost savings due to distributed solar.

He then summarily concludes that "[t]hese benefits will more than offset any integration costs."[73] I disagree with Mr. Beach, for the same reasons that have already been presented extensively in Duke's Reply Comments.[74] Unlike Duke's continuing recognition of an adjustment to the avoided energy calculation for the quantifiable "benefit" or savings to the utility resulting from reduced line losses associated with energy delivered by distribution-connected QFs, the two categories of costs identified by Witness Beach are speculative and not real costs that will be avoided from QF purchases. Mr. Beach has also failed to explain why the Commission's consideration of these purported benefits should "offset" the actually-quantified increase in ancillary services costs caused by solar QF generators. Accordingly, Mr. Beach's reasoning for opposing the Integration Services Charge should be rejected.

Q. HOW DO YOU RESPOND TO NCSEA'S RECOMMENDATION THAT THE COMMISSION SHOULD REJECT THE INTEGRATION SERVICES CHARGE AND INSTEAD PURSUE AN ANCILLARY SERVICES MARKET OR EIM TO ENABLE SOLAR QFS TO PROVIDE ANCILLARY SERVICES?

A. First, even if the Commission were inclined to promote the competitive procurement of ancillary services, it does not logically follow that this policy directive would somehow support rejecting the Integration Services

[73] NCSEA Beach Direct Testimony, at 8.
[74] Duke Reply Comments, at 30, 123-131.

Charge. Market constructs establish rules and frameworks for promoting new investment and transacting for a needed commodity between willing buyers and sellers, here, ancillary services. However, Duke must still pay for the ancillary services, *i.e,* the "needed commodity," regardless of how it is procured. As explained by Duke Witness Wheeler, the Integration Services Charge assures that the costs of these incremental ancillary services requirements are recovered from the solar generators who are the cost causers versus from retail customers. If at some future point outside of the scope of this proceeding, an EIM Market is formed that includes DEC and DEP Balancing Areas, the biennially updated Integration Services Charge would then reflect that future market. However, the formation of such a market is highly unlikely to occur before the next biennial avoided cost proceeding, when the Companies propose to next review and update the Integration Services Charge.

NCSEA Witnesses Beach and Harkrader also seem to be suggesting that market framework for procuring ancillary services would enable third party QF developers to make new investments to provide such ancillary services more cost effectively than Duke. However, as recognized by Public Staff Witness Thomas, the Duke-owned generating fleet currently has sufficient available capacity to meet the relatively-limited additional ancillary services requirements (26 MW in DEC and 166 MW in DEP) identified as currently needed to manage the incremental volatility of QF solar; therefore, it is unclear what "need' the new third-party investments solicited through an entirely new ancillary services market would be addressing. Put another way, customers would not benefit from this new market as they would continue to pay for the Duke fleet as well as new resources procured through a market to provide the ancillary services.

Putting aside the ill-conceived recommendation to simply replace the Integration Services Charge with a new ancillary services market, I also do not believe a Commission directive in this proceeding to pursue an ancillary services market is reasonable or proportionate to the scope of this biennial avoided cost proceeding. Such a recommendation would raise a significant number of complex legal, regulatory, and technical issues that are outside the scope of this proceeding, which is focused on North Carolina's implementation of PURPA. I also agree with Public Staff Witness Thomas' testimony that PURPA obligates the Companies to purchase a QF's energy and capacity at avoided costs but does not obligate the utility to purchase ancillary services from a QF.[75]

It is also important for the Commission to recognize the significant benefits afforded to QFs in North Carolina as compared to deregulated jurisdictions. QFs in North Carolina retain the full benefit of PURPA's must-purchase obligation, along with other opportunities such as the Competitive Procurement of Renewable Energy ("CPRE") Program established in Session Law 2017-192 ("HB 589") to sell their full output to Duke. In contrast, QFs in other parts of the Country where energy, capacity

[75] Public Staff Thomas Direct Testimony, at 25 (citing 18 C.F.R. 292.303(a)).

and ancillary services are procured through organized markets are not similarly guaranteed a right to sell their full output to the utility at the utility's long-term forecasted avoided costs and must compete in these markets. Similar to Dr. Johnson's advocacy for a rate design that guarantees QFs fixed average costs from the outset of their contract as well as market price signals during the term of the contract, NCSEA's other witnesses also want to have it both ways, seeking to retain the right to sell under the PURPA must-purchase obligation while also advocating for an ancillary services market.

Q. DOES THE SISC STIPULATION PROVIDE A REASONABLE FRAMEWORK TO ENABLE SOLAR QFS TO EFFECTIVELY "PRICE" THE ANCILLARY SERVICES CAUSED BY THEIR INTERMITTENCY AND TO RESPOND TO THIS PRICE?

A. Yes. I believe the SISC Stipulation does provide solar QFs pricing signals to evaluate the "market opportunity" to make incremental investments that could enable Duke to avoid incurring the increased ancillary services requirements caused by the uncontrolled volatility and intermittency of their operations. NCSEA Witness Harkrader candidly testifies that "solar QFs have no financial incentive to minimize the ancillary service requirements that they impose on the grid" and "[f]or this reason, NCSEA has proposed in this proceeding that the Commission adopt pricing for ancillary services."[76] The Astrapé Study effectively quantifies or "prices" Duke's

[76] NCSEA Harkrader Direct Testimony, at 13.

costs to provide the ancillary services attributable to the uncontrolled intermittency of solar generators which the Integration Services Charge is designed to recover. As I discuss further below, Section II.A of the SISC Stipulation provides a mechanism for technologically-capable "controlled solar generators" that contractually commit to materially reduce or eliminate the intermittency and intra-hour volatility that causes Duke to incur the increased ancillary services costs to avoid the Integration Services Charge.

Q. IS NCSEA WITNESS HARKRADER'S RECOMMENDATION THAT EXISTING QFS SHOULD BE ALLOWED TO AVOID THE INTEGRATION SERVICES CHARGE WHEN THEIR EXISTING PPAS EXPIRE APPROPRIATE?

A. No. This position would be unfair to both other QFs and to customers. As further addressed by Witness Wheeler, the Integration Services Charge has been quantified based upon the "average" ancillary services costs that all uncontrolled solar generators are imposing on the system. Accordingly, the SISC Stipulation appropriately provides that all solar QFs that commit to enter into a new PPA after November 1, 2018 will be subject to the Integration Services Charge. Witness Harkrader's position inappropriately seeks to advantage existing QF solar generators over new "incremental" QF solar generators even though all uncontrolled solar generators impose ancillary costs on the grid. It also would extend the current subsidization of these existing QFs by customers who continue to pay these ancillary

146

services costs for the duration of the existing QFs' PPAs. Duke's position, as agreed to by the Public Staff in the SISC Stipulation, is that all QFs committing to enter into new PPAs at the expiration of their current PPA are equally responsible for the integration costs and will be equally subject to the charge.

Q. DO YOU AGREE WITH NCSEA WITNESS BEACH THAT THE ASTRAPÉ STUDY ERRONEOUSLY ASSUMES THAT FUTURE SOLAR BUILT IN NORTH CAROLINA WILL RESEMBLE SOLAR THAT HAS BEEN INSTALLED TO DATE?

A. No. In my opinion, the Astrapé Study appropriately recognizes the incremental ancillary services costs of solar to be developed in the near future in North Carolina, and, importantly, the Companies have committed to biennially update the Study in the future. Mr. Beach fails to recognize that the Integration Services Charge is purposefully designed to quantify the ancillary services costs based upon the existing plus HB 589 transition ("Existing Plus Transition") solar capacity in DEP (2,950 MW) and DEC (840 MW), all of which is already either installed or under development and legally committed to be purchased under pre-existing avoided cost rates and rate designs. To the extent that the design and operational characteristics of solar built in the future deviates from existing solar generators, those changes will also be appropriately identified in future biennial reviews and updates to the Integration Services Charge.

Q. IS NCSEA WITNESS HARKRADER CORRECT THAT DUKE WILL PROVIDE "SOLE OVERSIGHT" TO FUTURE BIENNIAL UPDATES TO THE INTEGRATION SERVICES CHARGE, AS AGREED TO IN THE STIPULATION?

A. No. As I explained in my direct testimony, Duke plans to update its quantification of the Integration Services Charge in future biennial avoided costs proceedings where it would be reviewed by the Public Staff and other intervenors and would be subject to approval by the Commission.[77]

2. <u>SISC Stipulation and Recognition of Differing Ancillary Services Costs for Innovative QFs</u>

Q. WHAT PROPOSALS DO INTERVENORS MAKE RELATED TO DIFFERING ANCILLARY SERVICES COSTS FOR INNOVATIVE QFS?

A. As I highlighted in my direct testimony, the Public Staff and NCSEA through their initial comments contend that certain QFs have the technical capability to reduce the additional ancillary services caused by the operation of uncontrolled solar QFs delivering intermittent energy to the Companies.[78]

Q. DOES THE SISC STIPULATION ADDRESS THIS RECOMMENDATION REGARDING INNOVATIVE QFS?

A. Yes. As discussed in Witness Wheeler's direct testimony, the Companies

[77] Duke Snider Direct Testimony, at 39.
[78] *Id.* at 41.

have agreed with the Public Staff in Section II.A of the SISC Stipulation that solar QF generators that design and commit to operate their Facilities in a controlled manner that materially reduces or eliminates the need for increased incremental ancillary service requirements may avoid the Integration Services Charge that would otherwise be imposed through a negotiated purchased power agreement.

Q. PLEASE EXPLAIN HOW "CONTROLLED SOLAR GENERATORS" CAN RELY UPON SECTION II.A OF THE SISC STIPULATION TO AVOID THE INTEGRATION SERVICES CHARGE.

A. Section II.A of the SISC Stipulation provides that a "controlled solar generator" that agrees in a negotiated PPA to materially reduce or eliminate the need for additional ancillary service 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, could avoid applicability of the Integration Services Charge.

As further described by Witness Wheeler, the Companies agreed to this provision as it reflects reasonable cost causation principles and allows a solar QF that is not imposing incremental ancillary service requirements due to its operations to avoid paying the Integration Services Charge. This provision of the Stipulation has the potential to benefit the Companies' system operators and customers through more coordinated dispatch and operational control of QF generating facilities that contractually commit to operate as controlled solar generators.

Q. DO THE CONTROLLED SOLAR GENERATOR PROVISIONS OF THE SISC STIPULATION SPECIFICALLY CONTEMPLATE THE ADDITION OF BATTERY STORAGE?

A. Yes. Where a solar QF proposes to integrate a battery energy storage system ("BESS") in order to enable the operational capability to qualify as a controlled solar generator, the SISC Stipulation specifically provides that the QF can avoid the Integration Services Charge by contractually agreeing to construct and operate its solar generating plus BESS facility to meet design specifications and operational requirements, as reasonably determined by Duke to be required to reduce or eliminate the need for additional ancillary services. Such contractual provisions would likely include design requirements relating to the relative capacity of the energy storage facility, operational control and performance requirements, as well as associated monitoring of the facility's operations and remedies for failure to comply.

Q. NCSEA WITNESS BEACH ADVOCATES THAT A SOLAR QF THAT INTEGRATES "SIGNIFICANT STORAGE" SHOULD BE ALLOWED TO AVOID THE INTEGRATION SERVICES CHARGE. DO YOU AGREE?

A. Potentially, if the requirements of Section II.A of the SISC Stipulation are met. NCSEA Witness Beach suggests that solar QFs integrating "significant storage," which he defines as a four-hour discharge capacity equal to at least 50% of the AC solar nameplate, should not be assessed the Integration Services Charge.[79] While I agree with Mr. Beach that a solar QF integrating a BESS of this size has the potential to meet the requirements of Section II.A of the SISC Stipulation, it is extremely important to recognize that the mere existence of a BESS does not automatically reduce or eliminate the need for the additional ancillary services requirements caused by the real-time intermittency and intra-hour volatility of uncontrolled solar generator operations.

Q. PLEASE EXPLAIN.

A. My Figure 1 below presents a simplified diagram of a solar plus Direct Current ("DC") connected BESS, which is "integrated" on the DC side of the DC/AC inverter and behind the point of interconnection with the Duke system.

[79] NCSEA Beach Direct Testimony, at 9.

Figure 1 – Solar plus DC-connected battery storage system diagram

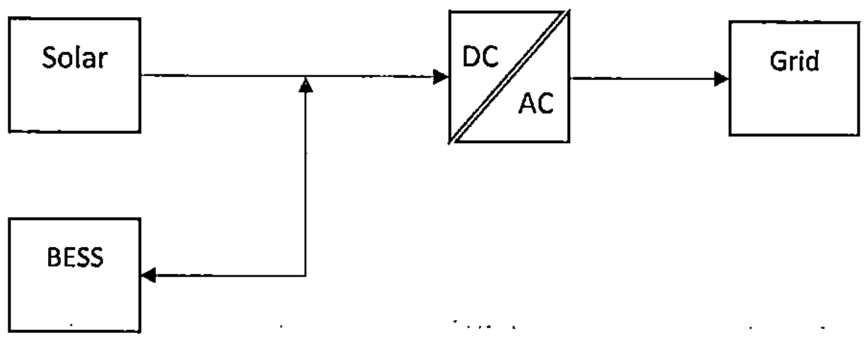


Figure 1 shows that during any minute or hour that the solar generator is producing energy, the energy generated can be delivered directly to the grid to serve system load through the Direct Current "DC" / Alternating Current ("AC") inverter, and/or the solar energy can be diverted and used to charge the BESS. The BESS can then be discharged to the grid through the DC / AC inverter during other time periods in a controlled manner. Importantly, this DC-integrated configuration assures that the BESS will be charged from the solar generator and cannot be charged directly from the grid.

Q. CAN YOU NOW ILLUSTRATE HOW A SOLAR + BESS INSTALLATION COULD OPERATE TO MATERIALLY REDUCE OR ELIMINATE ANCILLARY SERVICES REQUIREMENTS AND TO ENABLE THE SOLAR GENERATOR TO AVOID THE INTEGRATION SERVICES CHARGE?

A. Figure 2 below presents an illustrative example of the 5-minute output of a standalone 40 MW solar facility operating on a winter day in the Carolinas.

The intra-hour volatility of the facility's output, which can be caused by phenomenon such as intermittent cloud cover, is one of the main reasons that the Utility is required to carry the additional ancillary services that are the driver for the Integration Services Charge.

Figure 2 –Uncontrolled Solar-Only Facility 5-Minute Output

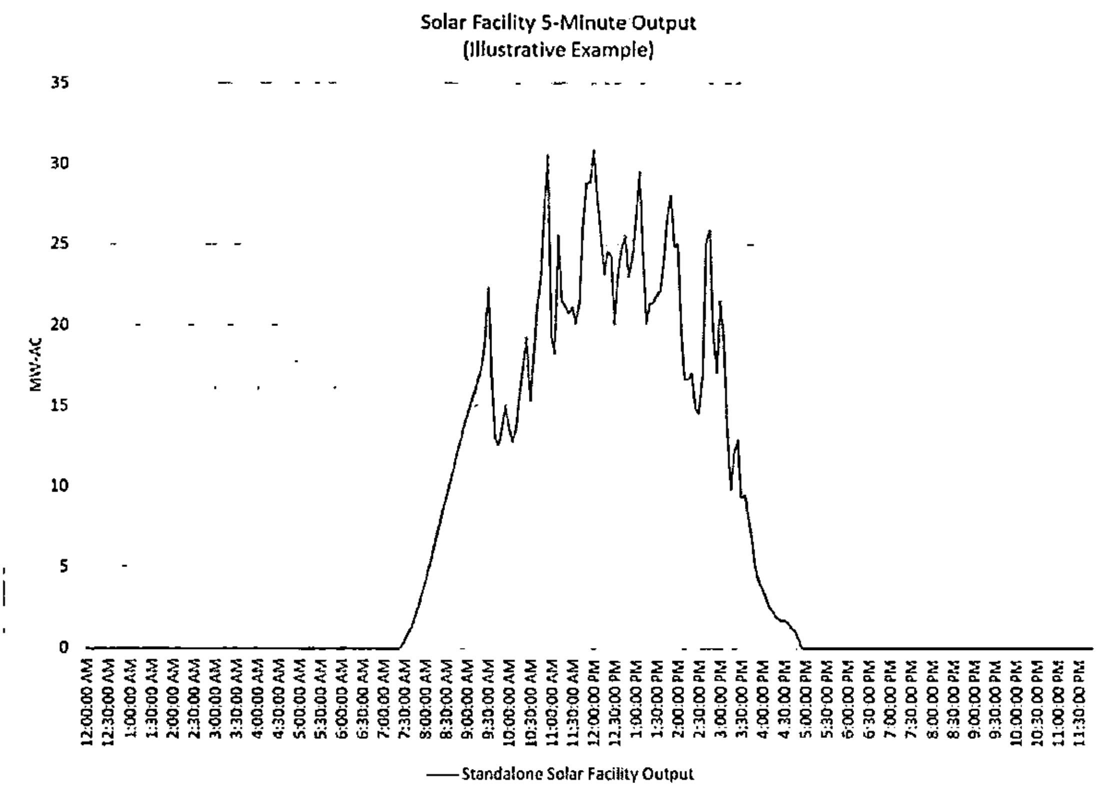
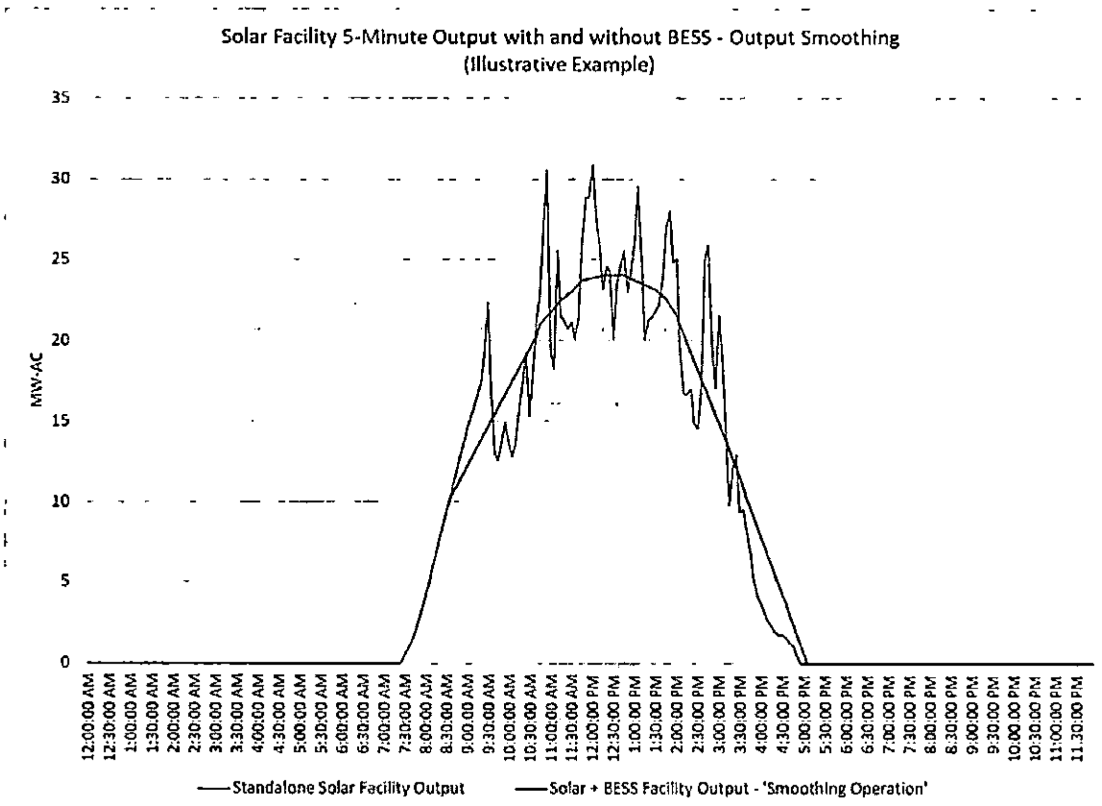


Figure 3 demonstrates how a BESS that is installed as shown in Figure 1 above, could be operated to "smooth" its delivered energy output (red line) by charging the battery when solar output quickly spikes and by discharging the battery when solar output quickly drops.

Figure 3 – Controlled Solar + BESS Facility 5-Minute Output Operated to Smooth the Facility's Output



In order to materially reduce ancillary service requirements, a solar + BESS facility would need to demonstrate that it could eliminate, or substantially reduce, the intra-hour volatility that is associated with a standalone solar facility as shown in Figure 3.

Q. OTHER THAN THE "SMOOTHING" OPERATION DESCRIBED ABOVE, HOW ELSE COULD A SOLAR + BESS SYSTEM BE OPERATED?

A. Based on the more granular energy and capacity price periods supported in the Rate Design Stipulation, discussed earlier in my testimony, there is a significant capacity value to the system, as well as economic incentive to the QF, if a solar generator could shift its period of energy production from off-peak hours to premium peak hours. As Public Staff Witness Thomas discusses and presents in Figure 1 of his testimony,[80] a solar + BESS facility could also be operated to optimize energy production during peak periods. My Figure 4 shows a 24-hour period of a standalone solar facility's 5-minute output across winter off-peak, winter on-peak (PM), winter on-peak (AM), and winter premium peak (AM) hours. The standalone facility operates with the intermittency and intra-hour volatility, as described previously, and only a small fraction of the facility's output occurs during the premium peak hours.

[80] Public Staff Thomas Direct Testimony, at 40, Figure 1.

Figure 4 – Standalone Solar Facility 5-Minute Output Across Winter Off-Peak, On-Peak, and Premium Peak Hours

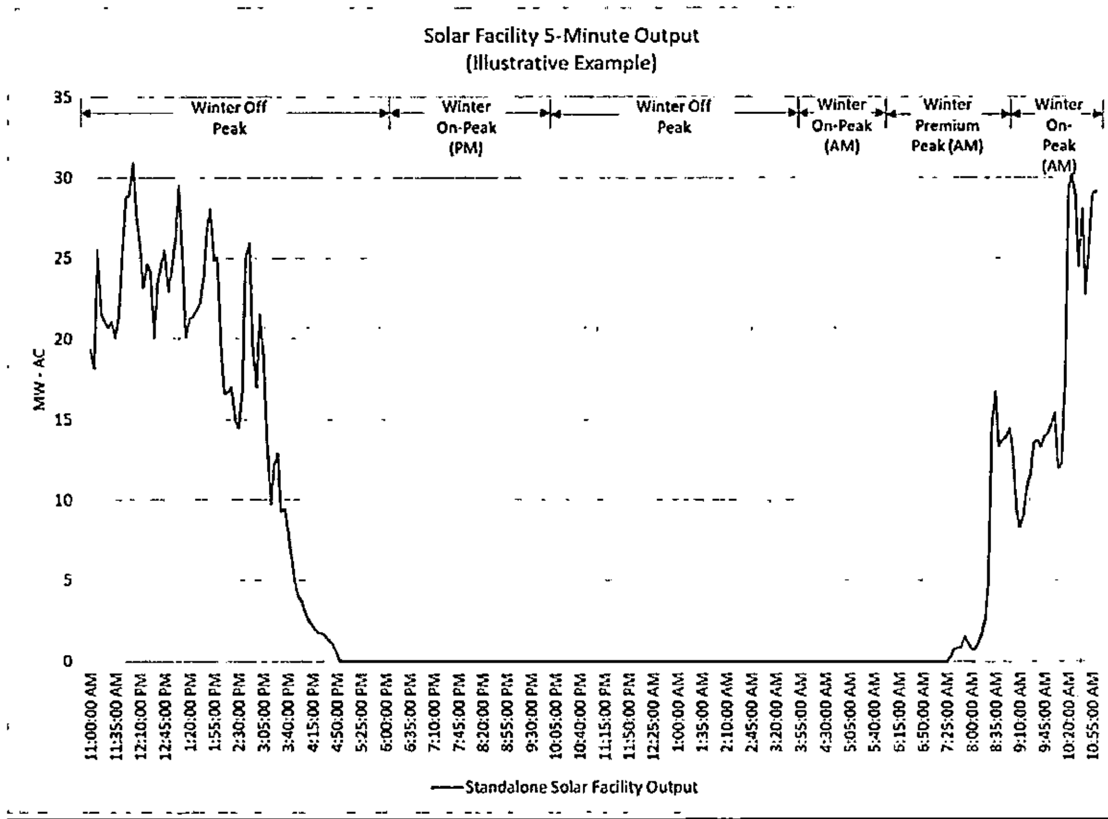
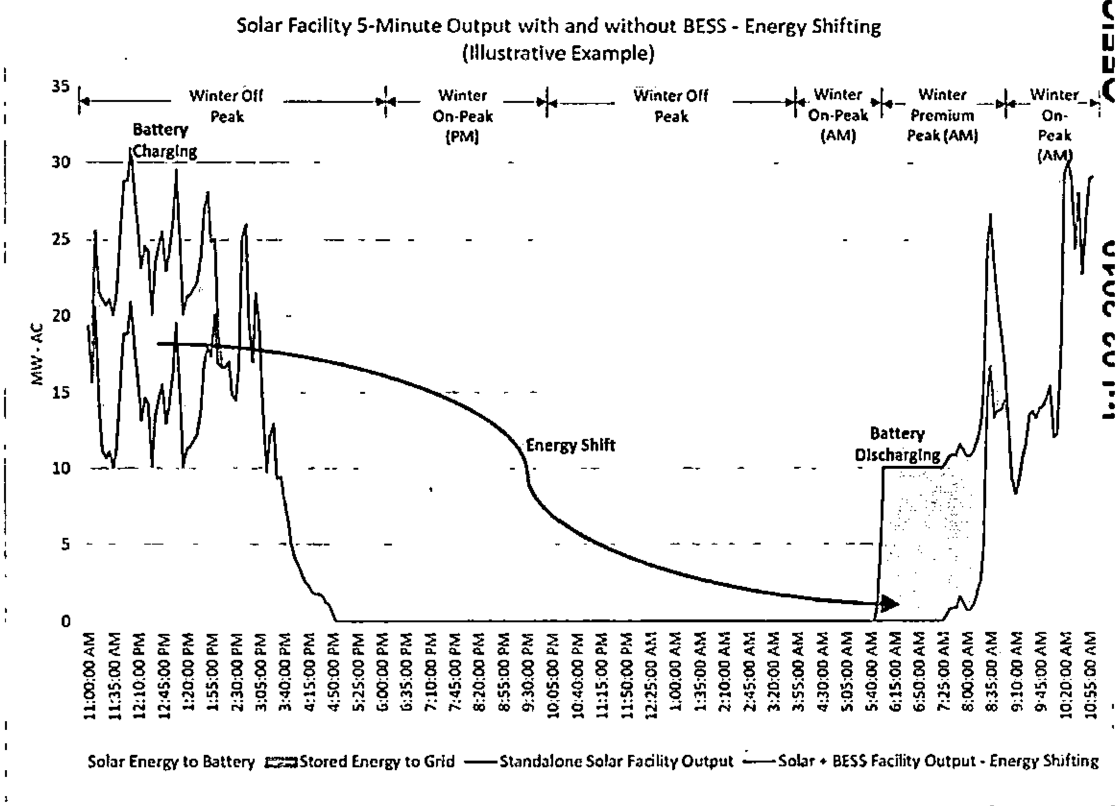


Figure 5 below illustrates how a solar + BESS facility could operate to shift energy by diverting a portion of the solar energy from the grid to the battery during off-peak hours on one day (represented by the grey area from 11 AM to approximately 2 PM) and then discharge that stored energy during winter premium peak hours the next day (represented by the yellow area from 6 AM to 9 AM). The red line in Figure 5 represents the total facility (Solar + BESS) output when the facility is being operated to maximize output during the winter premium peak hours.

Figure 5



When the solar + BESS facility is operated in this manner, the total facility output is lower during off peak hours and higher during premium peak (or on-peak) hours.

Importantly, while this operation provides capacity benefits to the utility by delivering during peak hours, as well as economic benefits to the QF by maximizing its energy delivery during the highest-value premium peak hours, it is important to note that operating the solar + BESS facility in this manner does not eliminate, or even reduce the intermittency and intra-hour volatility of the facility as was achieved in the "smoothing" example that I presented in Figure 3 above.

Q. COULD A SOLAR + BESS FACILITY BOTH "SHIFT" ENERGY TO MAXIMIZE OUTPUT DURING PEAK HOURS AND ALSO "SMOOTH" ITS OUTPUT IN ORDER TO MATERIALLY REDUCE OR AVOID THE APPLICABILITY OF THE INTEGRATION SERVICES CHARGE?

A. Possibly. However, as stated previously, a facility of this type would need to demonstrate that it can systematically reduce or eliminate the intra-hour volatility of the base solar facility before it would be allowed to avoid any of the Integration Services Charge.

Q. PLEASE RESPOND TO NCSEA WITNESS HARKRADER'S CONCERNS THAT THE SISC STIPULATION REQUIRES SOLAR FACILITIES TO ALLOW DUKE TO DICTATE DESIGN AND OPERATIONAL PROTOCOLS.

A. NSCEA Witness Harkrader expresses concern that the SISC Stipulation would require solar developers to negotiate and enter into negotiated PPAs with Duke where Duke can dictate solar facility design and operational requirements.[81] While true, it is important to recognize that opting to design and operate the solar QF as a controlled solar generator is not the QF's only path to a PPA. A QF solar generator may simply elect to pay the Integration Services Charge and pursue uncontrolled discharge to the grid (i.e., use the storage resource to shift energy from lower price off-peak hours to higher price premium- and on-peak hours as identified in Figure 5). In order to

[81] NCSEA Harkrader Direct Testimony, at 15.

avoid the applicability of the Integration Services Charge, which is designed to recover the incremental ancillary services costs caused by the intermittency of solar QF operations, Duke and the Public Staff agree that it is reasonable to require the QF to design and operate its facility to mitigate the intermittency associated with its uncontrolled operations that the charge is designed to recover. The Stipulation provides that required design specifications and operational requirements must be "reasonably determined by Duke," and I anticipate that both the QF industry and the Public Staff will have an interest in these requirements, as a solar QF's avoidance of the SISC essentially means that any incremental ancillary costs incurred by Duke due to the QFs' operations will be recovered from retail customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

159

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of:	)	**SUPPLEMENTAL TESTIMONY**
	)	**OF GLEN A. SNIDER**
Biennial Determination of Avoided Cost	)	**ON BEHALF OF DUKE**
Rates for Electric Utility Purchases from	)	**ENERGY CAROLINAS, LLC**
Qualifying Facilities – 2018	)	**AND DUKE ENERGY**
	)	**PROGRESS, LLC**

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

A. My name is Glen A. Snider, and I am the Director of Carolinas Resource Planning and Analysis for Duke Energy Corporation. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS SUPPLEMENTAL TESTIMONY?

A. I am submitting this supplemental testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke").

Q. ARE YOU THE SAME GLEN A. SNIDER WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to respond to the Commission's June 14, 2019 *Order Requiring Supplemental Testimony and Allowing Responsive Testimony* ("Order") requesting that the Utilities address the avoided cost rate schedule and contract terms and conditions that a Qualifying Facility ("QF") proposing to add battery storage to its electric generating facility would receive under North Carolina's implementation of the Public Utility Regulatory Policies Act ("PURPA").

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. No. However, my testimony incorporates by reference the Companies' Reply Comments filed on March 27, 2019, which also address the issue presented in the Order for supplemental testimony.

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE ISSUE THAT THE COMMISSION HAS REQUESTED THE COMPANIES AND OTHER INTERESTED PARTIES TO ADDRESS THROUGH SUPPLEMENTAL TESTIMONY.

A. The Order was issued contemporaneously with the Commission's *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony* in Docket No. E-100, Sub 101 ("Interconnection Standard Order"). Among the issues addressed in the Interconnection Standard Order, the Commission considered whether an Interconnection Customer's request to integrate a battery storage system and to either modify a proposed generating facility identified in a pending Interconnection Request, or to modify an operating generating facility under an Interconnection Agreement, would constitute a "material modification" under the North Carolina Interconnection Procedures.

The Interconnection Standard Order focused on the regulatory and contractual requirements governing physical interconnection and ensuring safe and reliable operations of the Duke system where a QF proposes to integrate battery storage. I understand the Commission's Order in this proceeding is focused on the regulatory and contractual requirements governing the Companies' purchased power obligations under North Carolina's implementation of PURPA where a QF proposes to add battery storage. The Order specifically directs the Companies to address the avoided cost rate schedule and contract terms and conditions that would apply when a QF proposes to add a battery storage system to an electric generating facility, and identifies three specific scenarios for consideration: (i) where a QF has established a legally enforceable obligation ("LEO") to sell power to the Companies, (ii) where a QF has executed a power purchase agreement ("PPA") with the Companies to sell its power over a specified term, or (iii) where a QF has commenced operations and is now selling the electric output of the facility to the relevant utility pursuant to an established LEO and executed PPA.

Q. BEFORE ADDRESSING THE ISSUE SPECIFICALLY RAISED IN THE ORDER, WHAT AVOIDED COST RATES AND TERMS AND CONDITIONS WOULD A NEW QF PROPOSING TO INTEGRATE BATTERY STORAGE AT ITS PLANNED QF GENERATING FACILITY RECEIVE UNDER NORTH CAROLINA'S IMPLEMENTATION OF PURPA?

A. Assuming that the proposed generating facility meets the legal and regulatory requirements to sell power to the Companies as a Small Power

Producer QF,[1] the Companies would treat a new QF proposing to sell power from a renewable QF that integrates battery storage the same as any other QF. Upon the QF establishing a LEO, Duke would offer to enter into a PPA to purchase the QF's full output based upon DEC's or DEP's most current avoided cost rates and terms and conditions as of the time the QF commits to sell its output to DEC or DEP. For QFs with a design capacity up to and including 1,000 kilowatts ("kW"), the QF would be eligible for Schedule PP. For QFs with a design capacity exceeding 1,000 kW, the QF would be eligible for a negotiated PPA.

Q. **NOW PLEASE ADDRESS DUKE'S POSITION REGARDING THE AVOIDED COST RATES AND TERMS AND CONDITIONS THAT A "COMMITTED" QF PROPOSING TO INTEGRATE BATTERY STORAGE WOULD HAVE A RIGHT TO RECEIVE.**

A. The Companies' position is that a "committed" QF proposing to integrate battery storage should not be allowed to do so without the utility's consent (if a PPA exists) and, in all cases, should enter into a new or modified PPA at the Companies' then-current avoided cost rates consistent with North

[1] *See* Duke Energy Reply Comments, at 147, addressing the regulatory requirements pursuant to which a generating facility integrating battery storage would be a Small Power Producer QF, as determined under the Federal Energy Regulatory Commission's ("FERC") implementing regulations.

Carolina's current PURPA implementation framework, as amended by Session Law 2007-192 ("HB 589").

Q. IS DUKE'S POSITION THE SAME REGARDLESS OF WHETHER THE "COMMITTED" QF HAS ONLY ESTABLISHED A NON-CONTRACTUAL LEO, HAS EXECUTED A PPA CONTRACTUALLY COMMITTING TO SELL ITS OUTPUT OVER A SPECIFIED TERM, OR HAS ALREADY BECOME OPERATIONAL WHEN THE QF PROPOSES TO ADD BATTERY STORAGE?

A. Yes.

Q. PLEASE ELABORATE ON THE COMPANIES' POSITION.

A. As discussed in the Companies' Joint Initial Statement and Reply Comments,[2] it would be inequitable and inconsistent with PURPA to allow QFs that have obtained a certificate of public convenience and necessity ("CPCN") from the Commission and previously made a legally enforceable commitment to sell their generating facility's output to Duke under legacy avoided cost rate schedules approved in the Sub 127 (2010), Sub 136 (2012), Sub 140 (2014), or Sub 148 (2016) proceedings to now increase their generator size (MW_{DC}), to increase their capability to produce energy in more hours of the day (MW_{AC}), or to shift their energy production to

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[2] Duke Joint Initial Statement, at 37-38; Duke Reply Comments, at 131-136.

make additional or modified sales at these pre-existing administratively determined rates that are significantly above Duke's current avoided costs.

Q. PLEASE EXPAND ON WHY A QF'S CHANGE IN TOTAL EQUIVALENT MW CAPACITY OR ENERGY PRODUCTION PROFILE WITHOUT A NEW LEO AND UPDATED PPA IS INCONSISTENT WITH NORTH CAROLINA'S IMPLEMENTATION OF PURPA.

A. Although PURPA requires utilities to pay QFs at the utility's full avoided costs, Congress also clearly said in enacting PURPA that such rates for purchase "shall not exceed" the incremental cost to the electric utility of alternative energy.[3] FERC's implementing regulations further expand on this requirement, stating that just and reasonable rates for purchases from QFs shall not exceed the utility's avoided costs over the term of the contract or LEO.[4]

North Carolina law implementing PURPA similarly provides that rates for purchases of energy from QFs "shall not exceed, over the term of the purchase power contract, the incremental cost to the electric public utility of the electric energy which, but for the purchase from a small power producer, the utility would generate or purchase from another source."[5] Due to recent declines in Duke's avoided costs over the past few years, as

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[3] 16 U.S.C. 824a-3(b).
[4] 18 C.F.R. 292.304(a)(2); (d)(2).
[5] N.C. Gen. Stat. § 62-156(b)(2).

well as Commission-directed improvements in the granularity and accuracy of the Companies' avoided capacity and energy rates, legacy avoided cost rate schedules now greatly exceed the Companies' current avoided costs. Allowing QF investors to integrate battery storage systems or any other technology that materially alters a QF's energy output or shifts power production under stale, legacy avoided cost rates would result in increased payments to QFs that exceed current avoided costs, in direct contravention of PURPA and HB 589's standard offer rate requirements.

For example, the addition of battery storage to an existing QF that has committed to sell under the legacy "Option B" avoided cost rate design would allow the QF to generate/discharge more power during legacy "on-peak" periods that no longer align with the Companies' highest marginal cost hours. In other words, absent the QF entering into a modified or new PPA reflecting Duke's current avoided costs and rate design, the addition of a battery storage system to an existing QF obligates the Companies, and thus their customers, to pay the QF for new and additional output in certain hours at rates exceeding the utility's now-current avoided costs, in a manner that was not contemplated by either the QF or the interconnecting utility at the time the QF originally committed to sell its output.

Q. PLEASE EXPLAIN WHY DUKE BELIEVES IT IS INCONSISTENT WITH PURPA FOR A QF TO RELY UPON AN EXISTING LEO TO MAKE NEW INVESTMENTS THAT MATERIALLY ALTER ITS FACILITY AND OBLIGATE CUSTOMERS TO PURCHASE THE

QF'S MODIFIED OUTPUT AT NOW-EXCESSIVE AVOIDED COST RATES.

A. The concept of a LEO is intended to assure that a QF is provided reasonable price certainty when the QF makes a binding commitment—a "legally enforceable obligation"— to sell to the utility. FERC's PURPA regulations also provide the QF the option to sell its output based upon the utility's avoided cost calculated at the time of delivery or, as has often been the case in North Carolina, based upon administratively-adjudicated estimates of forecasted avoided costs calculated at the time the LEO is established.[6] Once that legally enforceable commitment is made, both the QF that obligated itself to sell its output over a specified term and the purchasing utility are bound for the duration of the LEO or contract. Since FERC's earliest implementation of PURPA in its 1980 Order No. 69, it has been clear that a QF cannot be deprived of the benefit of its binding commitment to sell due to changed circumstances after a LEO has been established. At the same time, however, FERC also recognized that a utility cannot be obligated to modify the terms of the LEO due to changed circumstances. Order No. 69 explained:

> The import of [18 C.F.R. 292.304(b)(5)] is to ensure that a qualifying facility which has obtained the certainty of an arrangement is not deprived of the benefits of its commitment as a result of changed circumstances. This provision can also ***work to preserve the bargain entered into by the electric utility***; should the actual avoided cost be

[6] 18 C.F.R. 292.304(d)(2).

> higher than those contracted for, the ***electric utility is nevertheless entitled to retain the benefit of its*** contracted for, or ***otherwise legally enforceable,*** lower price for purchases from the qualifying facility. This subparagraph will thus ensure the certainty of rates for purchases from a qualifying facility which enters into a commitment to deliver energy or capacity to a utility.[7]

Duke recognizes that existing QFs have established LEOs, obtained financing and constructed generating facilities based upon prior administratively-determined estimates of future avoided costs. Under PURPA, the Companies cannot force these QFs to abandon their LEO and/or contractual rights to continue to receive payments at avoided cost rates that are now projected to significantly exceed the utility's avoided cost at the time of delivery for the remainder of the contracted-for term.[8] However, allowing a QF developer to now make incremental investments to add battery storage and be compensated for such investment at pre-existing and now-excessive avoided cost rates would be unjust and unreasonable because it would burden consumers with incremental charges for capacity and energy that are above current avoided cost values. This result would seem to violate North Carolina law and PURPA, as it would require the utility and its customers to pay rates exceeding avoided cost for

[7] Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, at 12224, FERC Stats. & Regs. ¶ 30,128 (1980) ("Order No. 69") (emphasis added).
[8] Duke Reply Comments, at 146.

QF power and, from the perspective of customers, even further worsen "the bargain entered into by the electric utility."

Q. DID THE QF HAVE THE OPTION TO COMMIT TO SELL ITS OUTPUT OVER A SHORTER PERIOD OR TO SELL AT AVOIDED COST AT THE TIME OF DELIVERY IF IT CONTEMPLATED AN INVESTMENT OPPORTUNITY ARISING TO MODIFY ITS GENERATING FACILITY?

A. Yes. PURPA provides the QF the option to elect to either deliver "energy-only" at the Companies' variable rates or to obligate the Facility to deliver its entire energy and capacity output over a specified term, such as the 5, 10, or 15-year contract terms available under the Schedule PP rates approved in Docket No. E-100, Sub 140. Additionally, it is also the QF's option to elect to sell its power based upon the utility's administratively determined avoided cost set prior to the contract term or based upon avoided cost calculated at the time of delivery. Over the last few years, QFs and their investors often selected forecasted avoided costs calculated over the longest term (15 years) in order to benefit from locking in higher, fixed-term, levelized avoided cost rates. Recognizing that these legacy LEOs and avoided cost rates now significantly exceed the Companies' actual marginal cost of energy at the time of delivery, it would be inconsistent with PURPA and unjust and unreasonable for Duke's customers to allow QF investors to now also seek to modify their originally committed QF generator to potentially sell more energy in certain hours than originally contemplated when its LEO was established or when a contract was executed. Duke and, by extension, its customers have no ability to escape the obligations to purchase energy from an existing QF even though the contracted rates now exceed actual avoided costs—but neither should the QF have the right to make additional investment to further leverage the excessive avoided cost. Authorizing such additional investments under a pre-existing committed LEO or PPA would simply amplify the current over-payment obligation facing customers today and exacerbate the "distorted marketplace" for QF power that this Commission previously acknowledged has already resulted in artificially high costs being passed on to North Carolina ratepayers.[9]

Q. IS DUKE OPPOSED TO ALLOWING A QF TO MODIFY AN EXISTING FACILITY TO ADD BATTERY STORAGE IF THE QF AGREES TO ENTER INTO A NEW OR MODIFIED PPA AT DUKE'S CURRENT AVOIDED COST RATES?

A. No. As previously mentioned, Duke's fundamental point is that the QF should not be authorized to materially alter its facility under a PPA without the utility's consent, and the utility should not consent to changes in a QF's committed equivalent capacity or energy output where the modified facility will require DEC or DEP to purchase power at rates above the utility's prevailing avoided cost. However, Duke is not opposed to considering

[9] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 16, Docket No. E-100, Sub 148 (Oct. 11, 2017).

entering into a new PPA or negotiating a modified PPA at Duke's current avoided cost rates and terms and conditions if an existing QF proposes to add battery storage.

Q. WILL COMMISSION APPROVAL OF DUKE'S MODIFIED TERMS AND CONDITIONS SUPPORTED BY DUKE WITNESS JOHNSON PROVIDE MORE CLARITY REGARDING THE IMPLICATIONS OF QF PROPOSALS TO ADD BATTERY STORAGE TO EXISTING QFS?

A. Yes. As further explained in Duke witness David Johnson's direct testimony, the Companies' proposed modifications to the standard terms and conditions addressing "material alterations" of QF generating facilities are intended to provide more clarity to QF owners and investors regarding the implications of proposals to integrate battery storage or to make other material changes to existing QFs.

Q. IS DUKE TAKING AN "ANTI-QF" POSITION BY NOT AGREEING TO PURCHASE POWER FROM PROSPECTIVE BATTERY STORAGE ADDITIONS UNDER PRE-EXISITNG COMMITTED LEOS OR PPAS?

A. No. If a previously-committed QF elects to pursue adding storage, Duke is willing to negotiate with the QF to modify their PURPA PPAs and/or prior commitments to sell in a manner that benefits consumers and that is compliant with the Companies' obligations under PURPA. QFs will also have the opportunity at the end of their current contract terms to modify their facilities and to negotiate a new PPA integrating storage at that time.

Q. **DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?**

A. Yes.

173

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of:	)	**JOINT SUPPLEMENTAL**
	)	**REBUTTAL TESTIMONY OF**
Biennial Determination of Avoided Cost	)	**GLEN A. SNIDER, STEVEN B.**
Rates for Electric Utility Purchases from	)	**WHEELER, AND DAVID B.**
Qualifying Facilities – 2018	)	**JOHNSON ON BEHALF OF**
	)	**DUKE ENERGY CAROLINAS,**
	)	**LLC AND DUKE ENERGY**
	)	**PROGRESS, LLC**

Q. MR. SNIDER, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glen A. Snider. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. MR. WHEELER, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven B. Wheeler, P.E., and my business address is 411 Fayetteville Street, Raleigh, North Carolina 27601.

Q. MR. JOHNSON, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David B. Johnson. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. HAVE EACH OF YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. We have each previously filed direct and rebuttal testimony in this proceeding on May 21, 2019, and July 3, 2019, respectively. Additionally, Mr. Snider filed supplemental testimony on June 25, 2019, in response to the North Carolina Utilities Commission's ("Commission") June 14, 2019 *Order Requiring Supplemental Testimony and Allowing Responsive Testimony* ("Order"). We are now appearing as a panel to support this testimony.

Q. WHAT IS THE PURPOSE OF YOUR JOINT SUPPLEMENTAL REBUTTAL TESTIMONY?

A. Our joint supplemental rebuttal testimony responds to the supplemental testimony submitted by Dominion Energy North Carolina ("DENC") witness James M. Billingsley, North Carolina Utilities Commission—Public Staff ("Public Staff") witness Dustin R. Metz, North Carolina Sustainable Energy Association ("NCSEA") witness Tyler Norris, Southern Alliance for Clean Energy ("SACE") witness Devi Glick, and Ecoplexus, Inc., ("Ecoplexus") witness Michael R. Wallace regarding the avoided cost rate schedule and contract terms and conditions that a Qualifying Facility ("QF") proposing to add energy storage to its electric generating facility would receive under North Carolina's implementation of the Public Utility Regulatory Policies Act ("PURPA").

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR JOINT SUPPLEMENTAL REBUTTAL TESTIMONY?

A. No.

Q. MR. SNIDER, PLEASE PROVIDE AN OVERVIEW OF THE COMPANIES' POSITION REGARDING THE AVOIDED COST RATES AND TERMS AND CONDITIONS THAT A "COMMITTED" QF PROPOSING TO INTEGRATE ENERGY STORAGE WOULD HAVE THE RIGHT TO RECEIVE.

A. As I explained in my initial supplemental testimony, Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP," and together with DEC, "the Companies" or "Duke") position is that a "committed" QF proposing to integrate energy storage should not be allowed to do so without the utility's consent (if a purchased power agreement ("PPA") exists) and, in all cases, should enter into a new or modified PPA at the Companies' then-current avoided cost rates consistent with North Carolina's current PURPA implementation framework, as amended by Session Law 2007-192 ("HB 589").

Witness Johnson explained in his direct testimony how the proposed "material alteration" definition clarifies the current Schedule PP Terms and Conditions to allow for routine repairs or replacement of equipment without utility consent, but would require a "committed QF" to obtain utility consent under an existing PPA to materially alter its generating Facility. Material alterations where consent is required would include where the QF owner proposes to increase the Facility's alternating current ("AC") Contract Capacity or to add energy storage or to "over-panel" the Facility to increase the direct current ("DC") nameplate capacity thereby enabling the generating Facility to sell more energy to the Companies.

In response to the Order, I emphasized in my supplemental testimony that Duke's position is not "anti-QF" and that Duke is not opposed to entering into a new PPA or negotiating a modified PPA at Duke's current avoided cost rates and terms and conditions if an existing QF proposes to add energy storage. However, Duke's fundamental point remains that a QF should not be authorized to materially alter its Facility under a legacy PURPA PPA without the utility's consent, and that the utility should not consent to changes in a QF's committed equivalent capacity or energy output where the modified Facility will require DEC or DEP to purchase power at rates above the utility's prevailing avoided cost. Such a result would burden our customers with overpayments for QF output and run counter to North Carolina's PURPA implementation framework as recently amended by HB 589.

Q. MR. SNIDER, IS DENC'S POSITION GENERALLY CONSISTENT WITH THE POSITION YOU PRESENTED IN YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes. DENC witness Billingsley agrees with Duke that allowing a committed QF to expand its maximum capacity, energy production, or shift its hours of production through the addition of an energy storage system at stale avoided cost rates burdens customers with overpayments and is in contravention of PURPA's requirement that utilities not pay more than their avoided cost for QF output.[1] He additionally agrees that a QF should not be permitted to expand its scope of operation beyond what was originally agreed upon through a previous PPA to either sell more output or to shift its output in a manner not originally contemplated by either the developer or utility.[2] Similar to the Companies, DENC witness Billingsley recommends

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[1] DENC Billingsley Supplemental Testimony, at 2-3.
[2] *Id.*

that a QF's addition of an energy storage system be compensated at the utility's current avoided cost rates.

Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S AND OTHER INTERVENORS' POSITIONS REGARDING THE CONTRACTUAL IMPLICATIONS OF A "COMMITTED QF" ADDING ENERGY STORAGE.

A. The Public Staff, NCSEA, and Ecoplexus each present a generally similar "compromise" (as characterized by NCSEA[3]) position regarding the contractual implications of a committed QF adding energy storage; these parties contend such a QF should be permitted to modify its original PPA to sell additional output of the energy storage system at current avoided cost rates while retaining the original, previously-committed avoided cost rates for the QF's original Facility's remaining output that is not used to charge the new storage device.

The Public Staff specifically agrees with Duke that it would be unreasonable to compensate a committed QF's additional energy resulting from the addition of energy storage at the QF's originally-committed avoided cost rates. As witness Metz states, the "additional energy" output resulting from a newly-added energy storage system should be compensated at "the most current avoided cost rates approved at the time the QF commits to sell the additional energy from the battery storage to the utility."[4]

[3] NCSEA Norris Responsive Testimony, at 6, 29-30.
[4] Public Staff Metz Responsive Testimony, at 5.

However, the Public Staff does not "necessarily" agree that a committed QF having added energy storage should be required to enter into a new PPA. Instead it supports allowing QFs to retain their prior contracted for avoided cost rates for their QF's original output delivered to the utilities prior to the addition of energy storage.

To implement this position, Public Staff witness Metz essentially proposes an "administrative solution," which includes quantifying the baseline output of the QF that originally established a Legally Enforceable Obligation ("LEO") to differentiate between the QF's "original" output and the "additional energy" output that would be generated once the addition of energy storage is completed.[5] He therefore recommends that a QF be allowed to modify its original PPA to allow the QF to receive the Companies' previously-committed avoided cost rates for the QF's "original" output and current avoided cost rates for the QF's "additional" energy storage output.

Mr. Metz candidly acknowledges the complexity of the Public Staff's proposal and the engineering challenges of metering energy storage generally, and ultimately concludes that a working group may be necessary to further discuss the implementation challenges associated with the addition of energy storage to a committed QF.[6] Ecoplexus witness Wallace supports the Public Staff's proposed approach.[7]

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[5] *Id.* at 6.
[6] *Id.* at 18.
[7] Ecoplexus Wallace Responsive Testimony, at 5.

NCSEA witness Norris argues that Duke's position will "wholly obstruct the addition of energy storage resources to all operating QFs in North Carolina," and instead presents NCSEA's "compromise" position, recommending that a QF should be allowed to modify its original PPA to allow the added energy storage system to be compensated at current avoided cost rates while the QF retains the pre-existing avoided cost rates for the original Facility.[8] Under NCSEA's proposal, the modified PPA "would maintain the remainder of the original PPA's terms and conditions, including the remaining PPA tenor," with the remaining tenor applicable to both the original Facility and the added energy storage system.[9] Witness Norris goes on to emphasize the importance to the QF industry of enabling the tenor of the modified PPA including the rates for the additional energy storage facility to extend for a term of 10 years, "at minimum."[10]

Last, SACE witness Glick contends that a committed QF that does not increase its AC capacity by adding energy storage should receive the original PPA rates where the addition of energy storage provides increased benefits to customers.[11]

Q. MR. SNIDER, PLEASE RESPOND TO NCSEA WITNESS NORRIS' ACCUSATIONS THAT DUKE IS BEING OBSTRUCTIONIST IN

[8] NCSEA Norris Responsive Testimony, at 27-28.
[9] *Id.* at 28.
[10] *Id.* at 29-30.
[11] SACE Glick Responsive Testimony, at 7.

ITS POSITION ON EXISTING QFS PROPOSING TO ADD ENERGY STORAGE.

A. NCSEA witness Norris appears to confuse measures that afford consumers protection from potential uneconomic PURPA purchases with intentional obstruction to QF development. Duke's position is in no way inconsistent with North Carolina's implementation of PURPA, nor is it obstructionist. As I testified in my initial supplemental testimony, Duke is agreeable to entering into a modified or new PPA with a QF that proposes to add energy storage, but believes that it is most appropriate for a QF seeking to materially alter its Facility to sell more energy to the Companies under PURPA to do so at current avoided cost rates, instead of at much higher avoided cost rates established as far back as 2010. Finally, irrespective of the outcome on this particular issue, the Companies simply act as an intermediary passing on costs of mandatory purchases of QF power to consumers. Conversely, existing PURPA must-take QFs have a single focus of increased equity returns for their existing projects with no obligation to consumers and very little accountability to the North Carolina Utilities Commission. Therefore, in my opinion, it appears disingenuous for a QF developer to claim Duke is the obstructionist and to imply that QFs are simply acting to enhance the value of their QF asset to benefit consumers.

Q. MR. SNIDER, DOES DUKE AGREE THAT THE ADDITION OF STORAGE TO OPERATING QFS WILL INHERENTLY CREATE

BENEFITS FOR THE CONSUMERS WHO WILL BE PAYING FOR THE QF'S ADDITIONAL ENERGY OUTPUT?

A. Not necessarily, and I think this is a critically important point for the Commission to appreciate. Witness Norris testifies repeatedly that the addition of storage resources can "enhance the value" of operating solar QFs, arguing that "[i]ndependent power producers should not be prevented from utilizing storage equipment to enhance the value of their property and the state's solar resource base."[12] However, the question is who reaps the benefit of the values created by the existing QF's incremental investment in integrating energy storage—our customers or the QF's developers and investors. From a "financial indifference" perspective, which is the touchstone of PURPA, Duke's position assures that customers will not be obligated to pay any materially altered QF, including those that add energy storage, at avoided cost rates greater than the utility's most current avoided cost.

Further, even under the "compromise position" offered by NCSEA and generally supported by the Public Staff, no inherent consumer benefits are created from the addition of energy storage. At best, assuming avoided cost rates are perfectly calculated and do not continue to decline, the position as articulated by these parties leave customers "indifferent" between adding storage or not. In other words, even if all the complex federal and state regulatory issues, contract law issues, and technical

[12] NCSEA Norris Responsive Testimony, at 17.

interconnection and metering issues associated with adding storage to an existing committed solar QF are resolved, customers will, at best, only be "indifferent" to adding storage because it would be procured from an uncontrolled must-take QF generator being dispatched to maximize revenue and being paid at the utility's full avoided cost value rather than at competitively bid prices.

Q. MR. SNIDER, IF THE COMMISSION WERE TO EXPRESS SUPPORT FOR THE COMPROMISE POSITION ADVOCATED BY NCSEA, SHOULD THE COMMISSION ALSO ESTABLISH AN EXPECTATION THAT ANY MODIFIED PPA SHOULD PROVIDE ADDITIONAL "CONSIDERATION" OR BENEFIT TO CONSUMERS?

A. Yes. NCSEA witness Norris is essentially advocating that the Commission direct Duke to accept modifications to existing QF-established legally enforceable obligations and existing QF PPAs and to modify these existing obligations to require customers to purchase additional energy from already-committed QFs that propose to add energy storage. Putting aside the question of whether the Commission should, or could, direct Duke to retroactively modify existing QF contracts during their term,[13] any QF proposing such a modification to a QF's existing commitments should

[13] Although I am not an attorney, Duke highlighted in its Reply Comments that FERC has clearly stated that a state regulatory authority may not abrogate or modify a QF contract to recognize that payments to QFs under that contract now exceed the utility's avoided cost. It would similarly seem inappropriate for the Commission to order a utility to modify an existing contract to the QF's benefit. *See* Duke Reply Comments, at 146.

reasonably be expected to offer additional benefits to consumers as "consideration" to justify the Companies' agreement to consent to the QF's proposed modification of its existing obligation. As I noted in my initial supplemental testimony, the Federal Energy Regulatory Commission ("FERC") recognized in Order No. 69 that PURPA's legally enforceable obligation framework ensures that QF investors are not deprived of the benefits resulting from making a legally enforceable commitment to deliver power at rates and terms fixed prior to the delivery period due to changed circumstances during the term of the PPA. FERC also recognized, however, that "this provision can also work to preserve the bargain entered into by the electric utility" who is "entitled to retain the benefit of its contracted for, or otherwise legally enforceable, lower price for purchases from the [QF]."[14] Recognizing North Carolina's recent economic and regulatory circumstances of surging QF development in a period of declining avoided costs, and the corresponding burden and risk of overpayment for that QF power that our customers bear,[15] I do believe that a QF owner seeking to enhance its investment through the addition of energy storage should be required to offer additional consideration that benefits consumers in exchange for Duke agreeing to modify the existing commitment to purchase the QF's output. This would be consistent with the foundational intent of

[14] Duke Snider Supplemental Testimony, at 9-10 (citing Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, at 12224, FERC Stats. & Regs. ¶ 30, 128 (1980)).
[15] *See* Part II of HB 589; N.C. Gen. Stat. § 62-110.8.

HB 589, which seeks to protect customers from overpaying for QF power and to procure renewable resources through market based pricing rather than long-term administratively-determined prices.[16]

Q. **MR. SNIDER, DOES DUKE HAVE ANY SPECIFIC RECOMMENDATIONS FOR THE ADDITIONAL CONSIDERATION OR BENEFIT TO CONSUMERS THAT WOULD BE APPROPRIATE IF A QF SEEKS THE UTILITY'S CONSENT TO MODIFY ITS COMMITTED QF PPA AND TO OBLIGATE CUSTOMERS TO PURCHASE ADDITIONAL ENERGY FROM THE ALREADY-COMMITTED QF PROPOSING TO ADD STORAGE?**

A. If the Commission decides to further investigate this complex issue, Duke believes that this investigation should include the quantification of the appropriate consideration or benefit to customers as a result of the additional costs imposed upon them. Duke is willing to discuss this with the Public Staff, QF developers, and other interested representatives of the solar industry. From my perspective, what is important would be for the Commission to provide clear guidance that any proposal to modify a committed QF during the term of an existing legally binding commitment or PPA should be evaluated by Duke and the Public Staff through the lens of ensuring that "customers benefit" from the incremental QF investment.

[16] N.C. Gen. Stat. § 62-110.8(g).

Q. DOES WITNESS NORRIS SUGGEST IT WOULD BE APPROPRIATE TO PROVIDE ADDITIONAL CONSIDERATION OR ENHANCED VALUE TO CUSTOMERS?

A. Seemingly yes. In criticizing Duke's position that a materially altered QF should be paid Duke's most current avoided cost, witness Norris suggests that it is unreasonable to require a QF proposing to add energy storage to enter into a new PPA "regardless of how the QF intends to utilize such equipment ***to enhance the value of the generator to the ratepayers***."[17] He also later questions Duke's motives by arguing that Duke should be "eager to accelerate the deployment of energy storage equipment on committed solar generators to enable greater dispatchability and to shift production to periods when it is most valuable to Duke Energy's customers."[18]

While Mr. Norris fails to provide any meaningful explanation or analysis of how integrating uncontrolled and QF-dispatched storage to an existing QF will "enhance the value of the generator" for consumers, I believe that this could be an area for discussion. For example, any storage device added to the system should adhere to the storage protocols that are currently being developed within the context of the CPRE process. Duke has also proposed to exempt QFs that committed to sell their output prior to this Sub 158 proceeding from the Integration Services Charge even though such generators impose similar incremental ancillary services requirements

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[17] NCSEA Norris Responsive Testimony, at 19 (emphasis added).
[18] *Id.* at 21.

to new QFs. Consideration of whether imposition of the Integration Services Charge (or a QF's contractual commitment to operate as a "Controlled Solar Generator") would be appropriate where a QF is making an incremental investment to add energy storage should also be discussed. Duke is also supportive of "enable[ing] greater dispatchability" and shifting QF production to periods when it is most valuable to customers, and welcomes meaningful, concrete proposals from the QF industry regarding how their addition of storage would accomplish these objectives in a manner that benefits consumers.

Q. MR. SNIDER, IS YOUR TESTIMONY THAT CONSUMERS SHOULD BENEFIT FROM ANY PROSPECTIVE MODIFICATION TO AN EXISTING OBLIGATION TO PURCHASE POWER FROM A COMMITTED QF ALIGNED WITH THE STATE'S RECENT ENACTMENT OF HB 589?

A. Yes. A central policy objective of HB 589 is to promote the continued development of more cost effective and reliable new renewable energy resources in a manner that benefits the North Carolina residents, businesses, and industries that ultimately pay for their power. HB 589 effectively limits the long-term financial exposure for consumers of uncontrolled "PURPA put" facilities in favor of competitive procurement of controllable and dispatchable renewable energy facilities to be procured and contracted for at rates at or below Duke's current estimates of future avoided costs. Under the CPRE framework, customers benefit from receiving the renewable attributes associated with CPRE assets delivered at rates below current avoided costs. Customers also benefit from the Companies receiving the right to dispatch, operate, and control third-party CPRE assets in the same manner as Duke's own solar fleet. Thus, I think any proposal where a QF owner is requesting to modify its existing QF that committed to sell power to Duke under the State's legacy uncontrolled PURPA must-purchase framework should be required to agree to modify its commitment consistent with the current PURPA implementation framework in a manner that benefits consumers, such as by committing to sell its output based upon the most current rate design or to agree to sales from the long-term storage facilities at something below current avoided cost. Obtaining more cost-effective solar was the clearly stated intent of HB 589, and Mr. Norris' expectation that the Companies should be expected to simply accept the QF's modified commitment and to purchase the output of new storage facilities at outdated avoided cost rates established years ago would simply be at odds with that intent.

Q. MR. SNIDER, DO YOU HAVE ANY OTHER CONCERNS WITH MR. NORRIS' COMPROMISE PROPOSAL IN LIGHT OF THE OBJECTIVES OF HB 589?

A. Yes. Mr. Norris suggests that an "essential element" of NCSEA's compromise is that the tenor of avoided cost rates available to the output of the storage equipment should be "set, at minimum, to the 10-year avoided cost rate (assuming at least 10 years of the QF's PPA schedule remains)."[19] Mr. Norris also suggests that NCSEA's recommendation should apply to both existing standard offer PPAs and negotiated QF PPAs for facilities up to 80 MW in size.[20] Thus, he is effectively advocating that Duke be required to calculate updated avoided cost rates for terms that are 10 years or longer for QFs selling under both legacy standard offer and negotiated PPAs. I do not see how this aspect of Mr. Norris' proposal can be squared with HB 589's express requirements regarding the tenor for avoided cost contracts entered into under North Carolina's implementation of PURPA. HB 589 expressly provides that the Companies should provide a standard offer avoided cost rate of 10 years to small power producer QFs with a design capacity of 1,000 kW or less and should fix rates for a five-year term for QFs not eligible for the standard offer. Although I do not dispute Mr. Norris' comment that nascent technologies such as energy storage may require "intentional regulatory support to enable its market entry and scale-up," I do not believe such QF industry-supported policy aims can justify deviating from the recently-enacted, express requirements of HB 589 governing PURPA implementation in the State.[21]

Q. MR. SNIDER, DO YOU HAVE CONCERNS THAT THE PUBLIC STAFF'S PROPOSAL TO PAY FOR "ADDITIONAL ENERGY" WHERE A QF PROPOSAL TO ADD ENERGY STORAGE COULD

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[19] NCSEA Norris Responsive Testimony, at 29.
[20] *Id.* at 27.
[21] *Id.* at 30.

RESULT IN CUSTOMERS NOT BENEFITING AND POTENTIALLY EVEN PAYING MORE?

A. Potentially, depending on the meaning of the Public Staff's use of the term "additional energy." With respect to an existing QF the term "additional energy" should be interpreted as any energy delivered to the system in excess of the "original QF's" output, as envisioned in the QF's FERC Form 556 certification, Interconnection Request, the Certificate of Public Convenience and Necessity ("CPCN") issued by the Commission authorizing construction of the Facility and, if executed, the PPA with the utility. Of great importance to our customers, however, is that the measurement of "additional energy" must be done for each pricing period of the PPA and not simply on an annual or monthly total energy delivered basis. Witness Metz's testimony is unclear on this critical point, and could be interpreted to be promoting energy arbitrage opportunities between pre-existing (and no longer accurate) off-peak and on-peak periods.

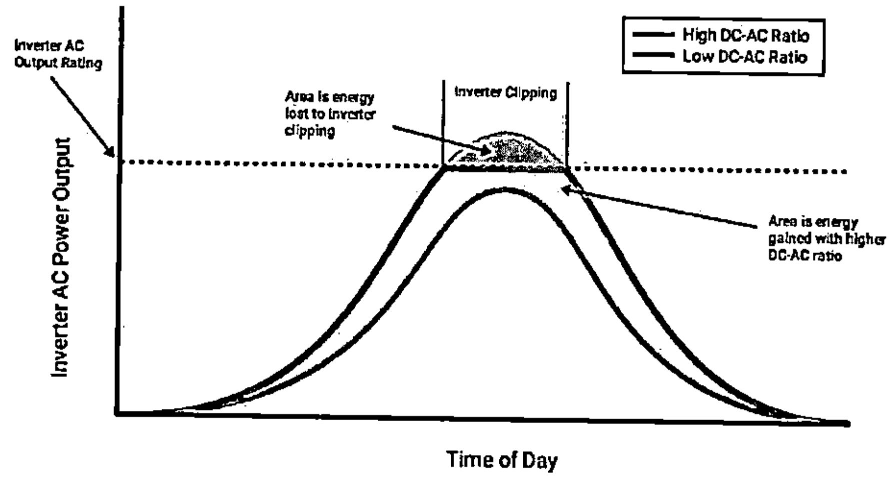
Consider the following simple hypothetical example: if a new energy storage device integrated with a solar QF results in a reduction of 50 MWh of "off-peak" energy delivered to the grid and an equivalent increase of 50 MWh of "on-peak" energy delivered to the grid, there would be 50 MWh of "additional energy" during the on-peak pricing period. When considering the implications of adding storage to an existing QF, it would not be appropriate to net reductions in off-peak against "additional energy" that is shifted and sold on-peak and to assert no "additional energy" was sold. To net and assume no "additional energy" was sold would essentially allow the QF owner to arbitrage the no longer accurate and now excessive avoided cost rates and pricing periods under the existing PPA in a manner that would exacerbate the overpayment situation already inherent in the PPA. As I explained in my direct testimony, this result would be inconsistent with PURPA. If the Commission is inclined to consider the Public Staff's proposal, developing a "baseline" of the original QF's energy production to ensure that all "additional energy" created as a result of the energy storage addition is appropriately valued at current avoided costs based upon the current avoided cost rate design will be vital to protecting our customers from taking on more overpayment obligations for this power.

Q. MR. SNIDER, OTHER THAN THE ADDITION OF BATTERY ENERGY STORAGE TO AN EXISTING SOLAR PPA, ARE THERE OTHER POSSIBILITIES FOR MATERIAL ALTERATIONS TO AN EXISTING SOLAR FACILITY THAT WOULD PRODUCE "ADDITIONAL ENERGY" THAT COULD HARM CONSUMERS?

A. Certainly. For example, Public Staff witness Metz[22] illustrates the difference in the production profile of a solar facility with a low DC-AC Ratio as contrasted to a High DC-AC ratio. For ease of reference, I have included his illustration below.

[22] Public Staff Metz Responsivé Testimony, at 8.

Figure 1: A visual representation of clipped energy



If an existing Facility were to enter into an original PPA with an initial output stated in the PPA at the lower purple line (a low DC-AC ratio) and then later in the term of the PPA installed additional panels that resulted in a new production profile similar to the green line (a high DC-AC ratio), it would result in additional energy being put to the grid represented as the shaded area in witness Metz Figure 1. In this example, if the new energy being put to the grid was priced at "stale" and now-excessive avoided cost rates in the original PPA, it would significantly increase the overpayment already inherent in the PPA. Another potential for increased output would be the replacement of fixed tilt solar arrays with single-axis tracking arrays which would also increase the output of an existing Facility.

Q. MR. SNIDER, DOES NCSEA WITNESS NORRIS REFERENCE THESE TYPES OF MATERIAL ALTERATIONS TO THE SOLAR FACILITIES CURRENTLY ON THE SYSTEM?

A. Yes. Witness Norris makes an incorrect analogy attempting to characterize the addition of energy storage and other similar material alterations as normal improvements any prudent infrastructure owner would make. He states, "[i]n the case of a utility-scale solar generator, whether owned by the utility or an independent power producer, such investments are to be expected and encouraged over an asset's lifetime, including replacements and upgrades to degraded photovoltaic modules, tracking array equipment, inverters, and beyond. These replacements and upgrades often incorporate advancements in technology and know-how, and any of them can modify the production profile of the facility."[23]

Q. WHAT IS THE FUNDAMENTAL PROBLEM WITH THIS ANALOGY MADE BY NCSEA WITNESS NORRIS?

A. Mr. Norris states that upgrades to existing solar facilities should be expected and encouraged whether it is a utility-owned facility or an existing independent power producer owned facility. NCSEA witness Norris ignores critical differences regarding the economic impact of such upgrades to the using and consuming public who ultimately bear the financial implications of such investments. Take for example, a representative existing QF independent power producer (*that originally was configured as a low DC-AC ratio facility*) that is delivering energy and capacity under a 15-year contract that was committed and executed in the E-100, Sub 136 or Sub 140 era. In this example, that QF is currently receiving average energy

[23] NCSEA Norris Responsive Testimony, at 18-19.

payments of over $60 per MWh for each MWh produced, well in excess of the value created at today's avoided cost rates. Assume 5 years into the PPA term that the QF requests DEC's or DEP's consent to materially alter the existing PPA by "upgrading" the Facility through the addition of new "low cost" panels to the existing Facility, enabling the QF to increase its energy output by 30 percent. The key here is that witness Norris seems to imply it should be expected and encouraged for the QF to pursue such profit-driven investments through the contracted-for QF and that the utility and consumers should be indifferent with buying the additional QF energy at the stale rates in the existing contract. In an environment of declining panel prices, such an investment may provide excellent returns for the QF. Unfortunately, those returns would come at the expense of consumers paying even more excess QF purchased power costs than they are already exposed to under the original commitment made to sell power from the Facility.

Q. WOULD A UTILITY-OWNED SOLAR FACILITY THAT ELECTED TO MAKE SIMILAR UPGRADES RESULT IN THE SAME POTENTIAL FOR CONSUMER OVERPAYMENT?

A. Not at all. As I have discussed in my rebuttal testimony in response to similar arguments,[24] attempts to equate how independent power producers recover their costs relative to utility assets placed into service under cost-based ratemaking fails to recognize significant difference in the regulatory

[24] Duke Snider Rebuttal Testimony, at 14-15.

framework governing independent power producers and fully regulated utilities. Utility assets would not be entitled to stale QF energy rates from years ago for incremental investments made to a utility-owned solar facility. Rather, the utility would assess the now current customer value from that incremental energy that resulted from the addition of new panels to the facility. The Companies would then compare the cost of the new panels to the value created by installing the additional panels based on current market conditions. If the now current customer value of the incremental energy created by the utility upgrade exceeded the cost of the panels, the utility would then elect to make the upgrade. Any excess value created from the additional output that exceeded the cost of the upgrade would flow directly to consumers. So in summary, the same upgrade that cost consumers significantly in NCSEA witness Norris's example would save money if the existing solar asset was a utility-owned asset that is "rate based" and recovered as part of the utility's cost of providing regulated utility service.

Q. MR. SNIDER, HOW DO YOU RESPOND TO NCSEA WITNESS NORRIS' CLAIM THAT "...THE RECENT REDUCTION IN DUKE'S ENERGY RATES BASED ON RECORD-LOW NATURAL GAS PRICES IS LIKELY TO BE A TEMPORARY PHENOMENON DUE TO THE LIKELIHOOD OF FEDERAL REGULATORY STANDARDS, WITHIN THE TENOR OF THESE QF PPAS..."[25]?

[25] NCSEA Norris Responsive Testimony, at 22.

A. Witness Norris asserts three concepts in his statement. One, that reductions in avoided cost rates are a recent occurrence based on record low natural gas prices. Two, that reductions are likely to be a temporary "phenomenon." Three, that federal environmental standards regulating natural gas are forthcoming over the term of the existing PPAs. To start, NCSEA witness Norris is simply incorrect on the first two points. Ten-year forward looking natural gas prices have been in a steady orderly decline for years. The Companies have repeatedly shown and demonstrated this by routinely obtaining market quotes and purchasing ten-year forward natural gas positions with prices reflected in the last several IRP and avoided cost filings going back to 2014. To further illustrate this point, the existing avoided cost rates as filed in this proceeding are not based on record-low natural gas prices. In fact, the Companies recently purchased ten-year natural gas forward positions at market prices for natural gas that are slightly lower than the gas prices used to develop the filed rates in this proceeding. This illustrates the risk to our customers of locking into administratively determined prices for long-term purchases. Finally, with respect to the potential for future increases in gas prices due to potential future regulations on the gas industry, witness Norris ignores that the probability of such an event is already factored into the forward market prices of natural gas. He also ignores the potential for future technical innovations to adapt to such regulations without disrupting natural gas markets. Irrespective of these omissions, if gas prices were to rise in the future, such increases would then be reflected in the prevailing avoided cost rates at that time. However, this does nothing to change the fact that stale historic long-term avoided cost rates are materially above current market conditions and have resulted in significant consumer overpayment for existing QF generation.

Q. TURNING NOW TO MR. WHEELER, HOW DO YOU RESPOND TO ECOPLEXUS WITNESS MICHAEL WALLACE'S TESTIMONY THAT IT IS TECHNICALLY FEASIBLE TO MEASURE ENERGY STORAGE SYSTEM OUTPUT ON THE DC SIDE OF THE POWER INVERTER AND POINT OF INTERCONNECTION WITH THE DUKE SYSTEM?

A. Witness Wallace contends that the Accuenergy data logger is capable of measuring DC electricity output and can be used to appropriately meter the separate battery energy storage system ("BESS") output from a solar + BESS facility installed on the Companies' system.[26] In addition, witness Wallace suggests that the utility may connect to a "cloud-based system for monitoring, sharing and displaying data" or "request information from the BMS and ESS provider to connect to the utility-owned SCADA system" to feasibly meter DC side electricity.[27]

I have several concerns with witness Wallace's proposal. First, metering the DC output of an energy storage device requires that the

[26] Ecoplexus Wallace Responsive Testimony, at 6-8.
[27] *Id.* at 5-6.

utility's meter be installed directly within the QF's electrical distribution system. This type of configuration is inconsistent with DEC and DEP's normal business practice of installing metering exclusively on the Companies' side of the point of interconnection. Duke's business practice is reasonable, as equipment installed on the QF's side of the point of interconnection is within the QF's total physical and electrical control, enabling the QF the opportunity to materially change the operation of such equipment without the Companies' knowledge or control. Additionally, different electrical safety standards apply to equipment installed on the QF's side of the point of interconnection than on Duke's side of the point of interconnection. The differing electrical safety standards applicable to the QF's side of the point of interconnection may unduly restrict Duke employees from working on a DC meter if the employees are not certified under both standards. Or, correspondingly, they require the Companies to incur increased labor costs solely for the benefit of QFs wishing to DC meter their BESS output.

Second, as witness Wallace correctly testifies, no American National Standards Institute ("ANSI") standards currently exist to judge the accuracy of the Accuenergy data logger meter for utility purposes:

> *"An AC revenue meter is governed by the American National Standards Institute ("ANSI") C12.1. ANSI 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."[28]

No ANSI standards applicable to DC metering currently exist primarily because utilities construct their systems based upon AC power standards. All customers are billed for AC usage; therefore, measurement of DC consumption or output is not a common or necessary utility practice. Additionally, adoption of a DC meter will require establishment and verification of new DC metering standards, development of testing procedures to validate DC meter accuracy, purchase and warehousing of DC meters and associated sensors, development of administrative guidelines to govern installation of the DC metering, training procedures on the use and installation of the DC meter, and other changes to the Companies' normal business practices solely to benefit the few QFs desiring to now materially alter their Facility to install energy storage devices behind their inverters.

A much simpler approach that is consistent with all other utility metering practices is to require measurement of the energy storage device output after it has been converted to AC and is delivered to the utility grid.

Q. MR. WHEELER, WHAT IS THE COMPANIES' CONCERN WITH USING MEASUREMENTS FROM A BATTERY MANAGEMENT

[28] *Id.* at 7.

SYSTEM ("BMS") OR ENERGY STORAGE SYSTEM ("ESS") FOR THE ENERGY OUTPUT OF AN ENERGY STORAGE DEVICE?

A. Witness Wallace's proposal[29] introduces a number of challenges that render his proposal currently infeasible. First, measurements from the BMS are not revenue grade and do not account for the conversion from DC to AC that take place in the inverter before energy is delivered at the point of interconnect. This is also a concern with Mr. Wallace's DC metering proposal. Although the information gained from these measurements may be useful for managing generator operations to monitor how the energy storage device is being discharged, it is not suitable for meeting revenue metering requirements.

Another flaw with witness Wallace's proposal is that most QFs are not connected to the utility's Supervisory Control and Data Acquisition or SCADA system. Although the Modular Energy Storage Architecture ("MESA") standard may help with communications, the utility must still provide the engineering to develop equipment standards, install that equipment, and maintain that additional communication with these sites. Finally, the utility would have the burden of reconciling the SCADA data from the BMS with the revenue meter data. In summary, this is a significant technical effort to sub-meter storage when compared with the reliability of a single revenue meter at the point of interconnection.

[29] *Id.* at 6-8.

Q. MR. WHEELER, HOW DO YOU RESPOND TO WITNESS METZ'S RECOMMENDATION[30] THAT THE COMMISSION CONSIDER FORMING A WORKING GROUP BASED UPON HIS BELIEF THAT THE COMPLEXITY SURROUNDING AN EXISTING QF'S ADDITION OF ENERGY STORAGE NECESSITATES FURTHER EVALUATION?

A. The Companies agree with witness Metz that the Public Staff's proposal raises a number of complexities that would require further evaluation. As Duke witness Snider has stated, and as Mr. Metz's testimony recognizes,[31] there are complex regulatory, contractual, metering, and technical issues raised by a committed QF's proposed addition of energy storage where "additional energy" is sold under a modified PPA at current avoided cost rates. If the Commission does not adopt the Companies' position requiring a new or modified PPA for the materially altered QF's full output, the Companies support the Public Staff's recommendation to establish a working group.

Q. MR. WHEELER, PLEASE RESPOND TO MR. NORRIS' ASSERTION THAT AN INCREMENTAL INVESTMENT TO ADD STORAGE IS ONLY AN "EQUIPMENT CHANGE"[32] TO SHIFT OUTPUT AND IS NOT MATERIALLY ALTERING THE QF.

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[30] Public Staff Metz Responsive Testimony, at 19.
[31] *Id.* at 15, 18-19.
[32] NCSEA Norris Responsive Testimony, at 20.

A. I disagree. First, the addition of energy storage is clearly a significant incremental investment to add new equipment and is not simply an equipment change such as changing out the inverters or fuses at a QF's Facility. The addition of energy storage will also likely materially alter the hourly production profile of the QF delivering power under the original PPA, and has the potential to either increase or decrease the total energy from the Facility depending on many factors such as the solar facility's DC-AC ratio and the ratio of nameplate solar relative to the nameplate battery being added. For perspective, if the addition of energy storage to an existing QF PPA is simply an equipment change and not a material alteration of the Facility, would the same hold true for the addition of any other small QF equipment under an existing PPA? For example, if the QF were to add a small cogeneration facility that only produced energy at night and did not increase the AC output of the original QF PPA, under witness Norris' logic that incremental investment could simply be deemed an "equipment change." I disagree, and also do not believe these "incremental investments" were contemplated by the legislature in the development of HB 589.

Q. MR. JOHNSON, IS NCSEA WITNESS NORRIS CORRECT THAT DUKE'S TARIFFS DO NOT PROHIBIT THE SHIFTING OF ENERGY UNDER A PPA[33]?

[33] NCSEA Norris Responsive Testimony, at 20.

A. No. While the Schedule PP Terms and Conditions for the Purchase of Electric Power do not specifically and expressly address energy shifting, the Schedule PP Terms and Conditions comprehensively reflect the overarching intent that energy generation from the QF Seller that originally contracted to deliver power to Duke will remain consistent over each year of the contract term. For example, Section 4(b) of the Terms and Conditions provides that "[t]he Seller shall not change its . . . contracted estimated annual kWh energy production without adequate notice to the Company, and without receiving the Company's consent." The Terms and Conditions were developed at a time when energy storage was not being installed and was not generally feasible for these projects. If storage was included as part of the original Facility design, it would have been identified in the Facility description included in the PPA. The shifting of energy would have also been addressed in the PPA.

Duke's negotiated form QF PPA, including several PPAs entered into between DEC/DEP and various Cypress Creek affiliates, include a detailed description of the contracted for Facility. This detailed description includes the QF's precise location, nameplate capacity rating, major equipment components, site map, layout, delivery point diagram, including delivery point, metering, and facility substation, and facility control equipment to be installed. Accordingly, the addition of a BESS or other energy storage equipment would be a material alteration of the Facility that contracted to deliver power to DEC or DEP, and, absent the Companies' consent, would constitute an event of default under the terms of the PPA.

In sum, the description of the Facility is a material term of both the Standard offer and negotiated QF PPA, and any material alteration of the Facility, including the addition of energy storage equipment, would require the Companies' prior consent. Furthermore, the unilateral material alteration of the Facility by the seller without obtaining the Companies' consent would be an event of default under both contracts. Accordingly, I disagree with Mr. Norris' assertion that Duke's addition of the Material Alteration definition and the associated requirement to obtain Duke's consent before a QF would be authorized to add energy storage is a significant change under the current standard offer Terms and Conditions.

Q. MR. JOHNSON, DOES DUKE AGREE WITH PUBLIC STAFF WITNESS METZ'S CLARIFYING AMENDMENT TO THE MATERIAL ALTERATION DEFINITION?

A. Mr. Metz's proposed grammatical amendment to the definition of material alteration[34] is not objectionable. This change further clarifies the Companies' intent that a QF's proposed modification to a Facility (as that term is now also clearly defined), which results in an <u>increase</u> to the Facility's Contract Capacity, Nameplate Capacity (in AC or DC), generating capacity (or similar term used in the Agreement) or the estimated annual energy production of the Facility (the "Existing Capacity") would

[34] Public Staff Metz Responsive Testimony, at fn. 22.

constitute a Material Alteration, while a decrease to the Facility's Existing Capacity by "more than five (5) percent" would constitute a Material Alteration. This distinction between increasing Existing Capacity and decreasing Existing Capacity is clearly identified in subparts (ii) and (iii) of the Material Alteration definition, but, again, witness Metz's further clarification is not objectionable.

Q. MR. JOHNSON, PLEASE COMMENT ON MR. METZ'S STATEMENT THAT "OVER-PANELING AND RE-PANELING"[35] WOULD LIKELY NOT BE CONSIDERED A MATERIAL ALTERATION SO LONG AS THE EXISTING CAPACITY IS NOT INCREASED OR IS NOT DECREASED BY MORE THAN 5%.

A. I partially agree with Mr. Metz. I agree with the general statement, but think in practicality that "over-paneling" implies that additional panels are being added to the Facility on the DC side of the inverter and would realistically increase the DC Capacity. I will note that his recognition that the Facility's Existing Capacity should not be increased is extremely important. I have previously testified that re-paneling or making other "like kind" equipment changes to repair or replace equipment at the QF's Facility is reasonable, and would not constitute a Material Alteration so long as the replacement doesn't increase the Existing Capacity (AC or DC). As provided for in the Companies' Material Alteration definition and as also recommended by

[35] *Id.* at 9-10.

Public Staff witness John Hinton,[36] the Companies will consider proposed modifications to QF Facilities in a commercially reasonable manner.

Q. MR. JOHNSON, PLEASE RESPOND TO SACE WITNESS GLICK'S TESTIMONY REGARDING THE APPROPRIATENESS OF THE COMPANIES' ENERGY STORAGE PROTOCOLS.[37]

A. As an initial matter, the Companies note that Duke's direct testimony, and not Duke's supplemental testimony, addresses the Schedule PP Energy Storage Protocols. Therefore, any intervener issues concerning the Protocols should have appropriately been raised through prior intervener testimony and not at this very late stage of the case. Notwithstanding the fact that the Companies' supplemental testimony does not address the Schedule PP Energy Storage Protocols, I am addressing SACE witness Glick's concerns.

Witness Glick argues that the Energy Storage Protocols "imprecisely target[] [] QF system sub-components," and, additionally, "impose[] a constant output requirement that could unnecessarily limit generation output..."[38] Regarding the former concern, witness Glick refers specifically to Items 4, 5, and 6 of the Schedule PP Energy Storage Protocols. Item 4 is intended to clarify that the entire facility, including the storage device, would be subject to any curtailment instruction from the system operator. Items 5 and 6 relate to allowable ramp rates for the Storage

[36] Public Staff Hinton Direct Testimony, at 18.
[37] SACE Glick Responsive Testimony, at 14.
[38] *Id.*

Resource, whereas the comparable language from the CPRE Tranche 1 Energy Storage Protocols related to the ramp rate requirement was represented as a percentage of the Facility Nameplate rating. This change was part of the Companies' overall effort to streamline the Schedule PP Energy Storage Protocols. Relating the ramp rate directly to the Storage Resource was intended to make this requirement more easily understandable for smaller QFs eligible for Schedule PP and to make the ramp rate requirement more uniform for different configurations of storage size relative to the facility size.

With respect to witness Glick's second concern, the primary intent of Item 7 is to ensure that the Storage Resource operates in a reasonably predictable way and does not exacerbate challenges with balancing the system by increasing variability relative to an uncontrolled solar only QF. For example, without a levelized output requirement, whether from the combined facility perspective or the Storage Resource perspective, a Seller with a one-hour battery could fully discharge their Storage Resource by 7:00 a.m. during winter months and be ramping back down while system load is still climbing toward the morning peak. This would increase system ramping requirements and make the system operator's job of balancing the system more challenging. The intent behind requiring levelized combined solar and storage facility output was to improve predictability and reduce system ramping requirements while allowing the Seller to maximize discharge of the Storage Resource to the extent practical. Rather than curtailing solar output in the winter morning scenario that Ms. Glick describes, the intent was to allow a higher level of storage output prior to sunrise and then to progressively reduce output from the Storage Resource as the solar output ramps up. This does assume that the Seller accounts for the expected operational mode and Premium Peak time periods in the storage sizing, as would normally be the case. The Companies have discussed this requirement with several developers, and no concerns were raised. Therefore, I do not agree with Ms. Glick's perspective, and continue to find these provisions of the more streamlined Schedule PP Energy Storage Protocols to be reasonable.

Q. MR. JOHNSON, DO YOU AGREE WITH WITNESS GLICK'S CONTENTION THAT PURPA DOES NOT ALLOW THE INTERCONNECTING UTILITY TO ESTABLISH COMMISSION-AUTHORIZED PROTOCOLS GOVERNING A QF'S ENERGY PRODUCTION PROFILE AND DELIVERY OF ELECTRICAL OUTPUT TO THE UTILITY'S GRID?

A. No. In arguing that the Companies' Energy Storage Protocols are "inappropriate," witness Glick states that PURPA does not allow Duke "control over" the QF's energy production profile and delivery of electrical output to the Companies' grid.[39] Although I am not an attorney, it is my understanding that PURPA expressly provides in 18 C.F.R. 292.308 that a state regulatory authority, such as the Commission, can establish reasonable

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[39] SACE Glick Responsive Testimony, at 13, fn. 22.

standards or protocols to ensure system safety and reliability of interconnected QF operations. As explained in my direct and rebuttal testimonies, the Companies' Energy Storage Protocols are reasonable and necessary to ensure the safe and reliable interconnection and parallel operation of QFs proposing to integrate energy storage systems. Notably, no other party to this proceeding has raised similar concerns, and Ms. Glick's comments should be rejected.

Q. DOES THIS CONCLUDE YOUR JOINT SUPPLEMENTAL REBUTTAL TESTIMONY?

A. Yes.

BY MR. BREITSCHWERDT:

Q Mr. Snider, do you have a summary of your testimony to present to the Commission today?

A Yes, I do.

Q Would you please present it at this time?

A Yes. My direct testimony supports the Companies' modifications to their Schedule PPs and the associated Terms and Conditions, as well as the updated avoided cost rates and the new integration services charge. I also provide an overview of Duke's position on issues identified in the Commission's April 24th, 2019 Order scheduling this evidentiary hearing.

First, with respect to IRP assumptions regarding expiring wholesale contracts, my direct testimony explains that prudent resource planning does not rely on assumed future third-party owned capacity in years where no PPA or legally enforceable obligation guaranteeing delivery exists. Accordingly, Duke's IRPs do not specifically include energy and capacity from existing wholesale PPAs, whether QF or non-QF, beyond a QF's guaranteed contract term. To provide greater transparency regarding each Company's first year of capacity need, however, Duke agrees with the Public Staff's recommendation to add a statement of need section to future IRPs, clearly identifying each Company's first year of an avoidable need and supporting factors used to determine such an avoidable need date.

Next, concerning NCSEA's recommendation to calculate the avoided capacity rate based on a hypothetical in-service date for standard offer QFs, my testimony explains the Companies' position that Duke's current practice of assuming an in-service date in the year following the November 1st biennial avoided cost filing date is a reasonable approach. Notably, the Utilities and Public Staff agree that this precedential approach treats existing QFs and new QFs equitably and should be retained.

The next part of my testimony discusses the rate design stipulation agreed upon between Duke and the Public Staff. My testimony explains how Duke received feedback from the Public Staff and Intervenors in developing its position on how Duke and the Public Staff reached consensus on a new, more granular rate design, as memorialized in the rate design stipulation. This more granular rate design is consistent with the Commission's prior orders and conforms with PURPA by ensuring customers are not paying more for -- more than the actual costs avoided by the Utility.

With respect to Duke's quantification of ancillary service costs of integrating solar, my testimony then discusses how the Companies commissioned a third-party consultant, Astrapé Consulting, to analyze the impacts of integrating solar into the Duke system and to quantify the increased costs of utilizing the DEC and DEP conventional fleet to provide the additional operating reserves or generation ancillary services needed to reliably integrate the various levels of intermittent solar generation. I explain how the resulting integration service charge reflects the current average cost of ancillary services caused by integration of intermittent solar generation and how the average rate will be appropriately adjusted in each future biennial avoided cost proceeding to reflect changing circumstances impacting the integration services charge. As discussed in more detail by Witness Wheeler, the Public Staff and the Companies also entered into a Stipulation where the Public Staff agreed with the Companies' proposed integration service charge. The Companies and the Public Staff further agree that to mitigate the financial risk of potential future increases in the average service charge, the integration service charge should be capped based on the QF's vintage of long-term fixed rates.

Finally, with respect to the proposals related to differing ancillary service costs for innovative QFs, my testimony discusses how the Stipulation between the Public Staff and Duke provides that solar QFs that demonstrate that their facilities materially reduce the need for increased incremental ancillary service requirements will not incur the integration service charge. These innovative solar QFs that desire to be exempt from an integration services charge must contractually agree to operate their facilities through the use of energy storage devices, dispatchable contracts, or other mechanisms that substantially reduce or eliminate the intermittency of the facility's output.

My rebuttal testimony responds to arguments raised by NCSEA and SACE about expiring wholesale contracts, the hypothetical in-service date for standard offer QFs, ancillary service costs, the potential for differing ancillary service costs for innovative QFs, and the rate design stipulation.

In my rebuttal testimony I discuss NCSEA Witness Johnson's position that Duke's IRP should continue to count capacity from QFs whose PPAs are expiring. He contends the Companies should continue to pay for capacity whether we need it to serve customers or not. In response, I explain the Companies treat all wholesale purchase contracts the same in their IRPs by recognizing that a QF's legally enforceable commitment to provide energy and capacity extends only for the duration of the contract, based upon PURPA and factual circumstances. This position is consistent with the FERC's regulations implementing PURPA which provide that QFs have the right to establish a legally enforceable obligation committing to the delivery of energy and capacity over a specified term. I further disagree with NCSEA Witness Johnson's recommendation that preexisting QFs should be allowed to establish a legally enforceable obligation three or more years in advance of its contract expiration to preemptively reserve capacity. Witness Johnson's recommendations are inconsistent with North Carolina's implementation of PURPA because they would prospectively commit the Companies to continue to pay for QF capacity without interruption even if the Companies' IRPs project that such a need does not exist in a given year.

NCSEA Witness Johnson also proposes that Duke use a hypothetical in-service date in order to enhance a QF's ability to earn capacity payments in years when Duke's IRP show a capacity need. As I detailed also in my direct testimony, the Public Staff, Dominion, and Duke all agree this unsupported proposal would be burdensome to the utilities, lead to uncertainty and misalignment of avoided cost rates, and deviate from the Commission precedent.

Next I discuss how SACE and NCSEA witnesses challenge the ancillary service study and integration service charge, but notably do not dispute that Duke is incurring integration cost. Specifically, I discuss how the costs of ancillary services are known and measurable as compared to hypothetical benefits identified by the Intervenors, and how NCSEA's recommendation that Duke enter into an ancillary service market or an energy imbalance market is beyond the scope of this proceeding.

Then I address NCSEA Witness Beach's argument that solar QFs that add significant storage should be allowed to avoid the integration service charge. The solar integration services charge Stipulation, as agreed upon with the Public Staff, specifically provides that a QF can avoid the charge by contractually agreeing to construct and operate any solar plus storage facility to meet design specifications and operational requirements reasonably determined by Duke. My testimony points out that the mere existence of battery storage, however, does not automatically eliminate the need for ancillary service requirements; these innovative QF facilities with battery storage must operate in a manner that demonstrates the storage device can reduce intra-hour volatility.

After discussing the integration service charge, I point out the flaws in NCSEA and SACE's arguments concerning the agreed-upon rate design Stipulation, highlighting inconsistencies with PURPA and House Bill 589, as well as the associated customer overpayment risk that would result from their positions. I further explain Duke's position that the rate design, as agreed upon by the Public Staff, complies with the Commission's prior direction to provide more granular price signals that reflect the Companies' actual avoided energy and production costs.

My supplemental testimony responds to the Commission's June 14th, 2019 Order requesting parties to address the avoided cost rate schedules and the contract terms and conditions that would apply in three scenarios: (1) where a QF has established a LEO to sell power to the Companies; (2) where a QF has executed a PPA with the Companies to sell its output over a specified term; and (3) where a QF has commenced operations and is now selling its output to the Utility pursuant to an established LEO and executed PPA. I explain how the Companies' position is that a QF that has previously made a legally enforceable commitment to sell its output to Duke under legacy avoided cost rates should not be allowed to add battery storage without the Utility's consent if a PPA exists and, in all cases, should enter into a new or modified PPA at the then-current avoided cost rates. Duke's position is the same, regardless of whether the PPA (sic) has established a non-contractual LEO, has executed a PPA, or has already begun operations when it proposes to add battery storage.

I conclude by explaining that Duke is willing to negotiate with an existing QF to enter into a new PPA at current avoided cost rates, terms, and conditions if the QF proposes to add battery storage. As explained by Duke Witness Johnson, the Companies' proposed modifications to the standard terms and conditions addressing material alterations to QFs are intended to provide more clarity to developers and investors regarding the implications of proposals to integrate battery storage or to make other material changes to their existing QFs.

My supplemental rebuttal testimony responds to the supplemental testimony of Public Staff Witness Metz, NCSEA Witness Norris, SACE Witness Glick, and Ecoplexus Witness Wallace. In this summary I explain that Duke's proposal does, in fact, support QFs proposing to add storage and in a reasonable and equitable manner. Because our customers must pay the cost of Duke's mandatory purchases of QF power, I address how the Companies' position on the addition of storage assures that customers will not be obligated to pay any materially-altered QF, including those that add storage, avoided cost rates exceeding the most current avoided cost. In conclusion, I discuss if the Commission were to determine that it should further investigate obligating customers to purchase additional energy from QFs proposing to add storage, Duke recommends that that investigation include -- should include quantification of the appropriate consideration or benefits to customers that results from an existing QF's addition of storage. Otherwise, allowing a QF to retroactively amend its PPA to add storage would obligate the Companies and their customers to pay for additional QF energy and capacity in a manner inconsistent with the clear intent of North Carolina House Bill 589.

This concludes my summary.

MS. FENTRESS: Thank you. I'll start with Mr. Wheeler.

DIRECT EXAMINATION BY MS. FENTRESS:

Q Mr. Wheeler, will you please state your name and business address for the record.

A (Wheeler) It's Steven Wheeler. My business address is 411 Fayetteville Street, Raleigh, North Carolina.

Q Mr. Wheeler, by whom are you employed and in what capacity?

A By Duke Energy Services Company. My business title is Pricing and Regulatory Solutions Director.

Q And did you cause to be prefiled in this docket on May 21st, 2019, 13 pages of direct testimony in question and answer form?

A Yes, I did.

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

A No, I do not.

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

A Yes, they would.

Q Okay. Did you also cause to be prefiled in this docket on July 3rd, 2019, 12 pages of rebuttal testimony in question and answer form?

A Yes, I did.

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

A No, I do not.

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, they would.

Q Did you also cause to be prefiled in this docket on July 11th, 2019, along with Mr. Snider and Mr. Johnson, 37 pages of joint rebuttal supplemental testimony in question and answer form?

A Yes, I did.

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

A No, I do not.

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

A Yes, they would.

MS. FENTRESS: Madam Chair, at this time I would move that the prefiled direct, rebuttal, and joint rebuttal supplemental testimonies of Mr. Wheeler be copied into the record as if given orally from the stand.

CHAIR MITCHELL: Without objection, that motion is allowed.

(Whereupon, the direct and rebuttal testimony of Steven R. Wheeler was copied into the record as if given orally from the stand. The joint supplemental rebuttal testimony was copied into the record on pages 173 through 209.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of:	)	**DIRECT TESTIMONY OF**
	)	**STEVEN B. WHEELER**
Biennial Determination of Avoided Cost	)	**FOR DUKE ENERGY**
Rates for Electric Utility Purchases from	)	**CAROLINAS, LLC AND DUKE**
Qualifying Facilities - 2018	)	**ENERGY PROGRESS, LLC**
	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven B. Wheeler, P.E., and my business address is 411 Fayetteville Street, Raleigh, North Carolina 27601.

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

A. I am the Pricing and Regulatory Solutions Director for Duke Energy Business Services, LLC ("DEBS"). DEBS is a service company subsidiary of Duke Energy Corporation ("Duke Energy") that provides services to Duke Energy and its subsidiaries, including Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC" or, collectively, the "Companies" or "Duke").

Q. PLEASE BRIEFLY STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received a Bachelor of Science degree in Mechanical Engineering from Virginia Polytechnic Institute and State University in 1976 and began employment with Carolina Power & Light Company, a predecessor of Duke Energy, upon graduation. I am a registered Professional Engineer licensed to work in the State of North Carolina. My initial employment with Duke Energy was in customer service where I was involved in promoting energy efficiency and electric technologies and later in meeting the electrical needs of industrial customers. I joined the Rate Department in 1982 and have held numerous positions in rate administration, regulatory services, rate design and pricing over the years.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I most recently prepared and presented testimony on rate design matters in DEP's North Carolina general rate case, Docket No. E-2, Sub 1142.

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

A. The purpose of my testimony is to support aspects of the Companies' petition to update the Companies' Schedule PPs and avoided cost rates and associated terms and conditions, as well as to support the Companies' proposed Integration Services Charge rate design applicable to intermittent solar generation. In particular, and in response to the North Carolina Utilities Commission's ("Commission" or "NCUC") April 24, 2019 *Order Scheduling Evidentiary Hearing and Establishing Procedural Schedule* ("Procedural Order") identifying discrete issues to be set for evidentiary hearing in this docket, I am providing expert witness testimony on issue d. "Duke's Proposed Solar Integration Charge 'Average Cost' Rate Design and Biennial Update."

Specifically, my testimony explains the Companies' proposed new Integration Services Charge rate design, and supports the Stipulation Agreement entered into between DEC, DEP and the North Carolina Utilities Commission—Public Staff ("Public Staff") that establishes a rate design to recover increased costs created by intermittent solar generation in an Integration Services Charge. The Stipulation was filed in this Docket on May 21, 2019. I will demonstrate that the proposed rate design reflects appropriate ratemaking principles and will result in an equitable basis for recovery of the increased cost associated with purchasing electricity from intermittent solar generation resources.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. No.

I. BACKGROUND

Q. PLEASE DESCRIBE THE PROCESS USED TO EVALUATE THE COSTS AND BENEFITS OF PURCHASING ELECTRICITY FROM QUALIFYING FACILITIES ("QF").

A. Duke routinely reviews the costs and benefits of integrating distributed generation into the Companies' transmission and distribution infrastructure. When sufficient evidence exists to quantify a specific cost or benefit, a detailed cost study is undertaken to quantify the incremental cost impact. The intent of the study is to determine how costs and benefits of integrating distributed generation can be assigned to purchased power customers instead of including such costs in the Companies' general cost of service to be recovered through base rates. The study quantifies the change in costs incurred by the Companies solely to support integration of the distributed resource into the Companies' delivery system and the purchase of the generation output. A common example of the study process is the Companies' review of Interconnection Customers' Seller or Administrative Charge, which similarly ensures that billing-related costs are properly recovered from the Interconnection Customer rather than included in the Companies' cost of service and base rates.

Q. WHAT IS THE BASIS FOR SEEKING INCLUSION OF AN INTEGRATION SERVICES CHARGE IN THE COMPANIES' PROPOSED PURCHASED POWER SCHEDULE PPS?

A. As identified in the testimony of Witnesses Nick Wintermantel and Glen A. Snider, the Companies' system now incurs increased ancillary service costs to regulate power flows due to the continually increasing amounts of variable, intermittent generation outputting to the system. As further explained by Witness Snider, this increased ancillary services cost impact is unique to intermittent generation; therefore, the proposed Integration Services Charge is proposed only to be applicable to solar photovoltaic generation resources. Although it may be appropriate to apply this type of charge to other intermittent generation sources in the future, the Companies lack sufficient experience to make a recommendation at this time.

Q. WHAT ANCILLARY SERVICES COSTS WERE QUANTIFIED IN THE ASTRAPÉ SOLAR ANCILLARY SERVICE STUDY?

A. The Astrapé Solar Ancillary Service Study ("Study") evaluated both the incremental and average cost of the increased ancillary services requirements caused by intermittent generation. The Study noted that higher costs are incurred whenever any intermittent resource interconnects with the grid, but the cost impact becomes more pronounced as the percentage of load served by intermittent generation resources increases. As discussed in greater detail by Witness Wintermantel, the Study analyzed the average and incremental ancillary services cost impacts based upon existing levels of solar deployment on the DEC and DEP systems, and also analyzed the impacts as future Competitive Procurement of Renewable Generation ("CPRE") resource additions occur. The difference in the average and incremental ancillary service cost impacts are laid out in Witness Wintermantel's testimony.

II. STIPULATION

Q. PLEASE DESCRIBE THE STIPULATION WITH THE PUBLIC STAFF REGARDING THE PROPOSED INTEGRATION SERVICES CHARGE.

A. As proposed by the Companies, the Integration Services Charge rate design reflects the current average cost of ancillary services cost caused by the integration of intermittent generation. In this proceeding, the level of generation used to derive the rate reflects the near-term development of the "Existing plus Transition" level of solar in DEC and DEP. The average rate will be reviewed and adjusted in each biennial proceeding and will apply to all new and existing QFs that are subject to the charge; however, a maximum rate limit or cap shall apply to QFs based upon their vintage of long-term fixed rates. In this proceeding, the cap reflects the estimated incremental cost of ancillary services based upon the amount of solar installations projected in DEC's and DEP's current 2018 integrated resource plans ("IRPs") to be installed at the end of 2020, which aligns with the point in time that the Sub 158 obligation expires with the initiation of the next biennial avoided cost proceeding. Even though both existing and new solar generators equally contribute to the higher ancillary services costs, consistent with the Companies' initial recommendation, the Stipulation provides that the Integration Services Charge shall only apply to QF

Sellers served under Sub 158 or later rates, or until the contract for existing QFs is renewed at more current rates.

Q. IS INCLUSION OF A CAP TO LIMIT FUTURE ADJUSTMENTS TO THE SOLAR INTEGRATION SERVICES CHARGE CONSISTENT WITH HOW OTHER COSTS INCURRED TO SERVE DISTRIBUTED GENERATION ARE TREATED?

A. No, it is not. However, the Companies recognize the Public Staff's concerns about the increased risk associated with possible future adjustments to the charge based upon future changes to the Companies' ancillary services costs during the term of solar QFs' PPAs.[1] Therefore, the Companies have agreed to cap future adjustments to the solar Integration Services Charge as a reasonable approach to address the Public Staff's concern and to offer QFs limited price certainty during their contract term. It is recognized that inclusion of a cap might result in some level of subsidization of QFs by the general body of customers if the average cost of these ancillary services continues to grow.

Q. IS THERE PRECEDENT FOR UPDATING INCREMENTAL COSTS INCURRED TO SERVE DISTRIBUTED GENERATORS WITH THE UPDATED CHARGE APPLYING TO ALL SELLERS?

A. Yes. As noted earlier, the Companies' Seller or Administrative Charge included in Schedule PP is routinely reviewed and updated to better reflect the billing-related cost and applies to all QFs upon approval by the Commission. Also, both utilities have recently reduced their carrying charge rate applicable to

[1] Public Staff Initial Comments, at 37-38 (filed Feb. 12, 2019).

interconnection facilities in recent general rate cases and immediately lowered the corresponding monthly facilities charge for interconnection facilities to all QFs. DEP also lowered its cost to provide VAR support in its recent 2017 rate case[2] and, upon approval by the Commission, lowered this rate for all QFs. The Companies believe that these types of cost should be periodically reviewed, updated and applied to all QFs, consistent with cost causation principles, to avoid subsidization of QFs by the general body of customers.

Q. WHY SHOULD THE INTEGRATION SERVICES CHARGE BE TREATED DIFFERENTLY?

A. Based upon the Companies' limited experience to date, it is anticipated that the Integration Services Charge may be more volatile than the previously cited costs; therefore, it may increase a Seller's financial exposure if it continues to increase with the addition of new intermittent resources to the grid. Offering a cap limits this exposure.

Q. HOW WILL THE INTEGRATION SERVICES CHARGE CAP BE ADDRESSED IN SCHEDULE PP?

A. Purchased Power Schedule PP filed with the Companies' Joint Initial Statement should be revised to include a statement establishing that future adjustments to the average Integrated Services Charge will not exceed the rate cap. The statement for DEC would read as follows: "In no event shall the Integration Services Charge exceed $0.00322 per kWh for Purchased Power Agreements

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

executed under rates approved in Docket No. E-100, Sub 158." The statement for DEP would be identical; however, it would include a rate cap of $0.00670 per kWh. The derivation of the rate caps is addressed in the testimony of Witness Wintermantel.

Q. DOES THE STIPULATION RECOMMEND THAT THE AVERAGE COST FOR SOLAR ANCILLARY SERVICES COSTS BE RECOVERED IN THE INTEGRATION SERVICES CHARGE?

A. Yes. The proposed Integration Services Charge rate design recognizes that all intermittent generation resources create this higher cost of service, not just new generation resources. It also recognizes that the Companies' costs are expected to change with increased deployment of intermittent resources, but will also vary in the future based upon actual load growth, the mix of the Companies' generation resources and potential impacts of electricity storage capability. These changes could all impact the significance of future changes in the Companies' average ancillary services costs over time. This potential for significant changes in the future makes developing an accurate long-term estimate that would be necessary to establish a longer-term fixed rate challenging.

Q. WHY SHOULD THE INTEGRATION SERVICES CHARGE NOT BE SET TO RECOVER THE INCREMENTAL ANCILLARY SERVICES COST TO PROVIDE CURRENT CUSTOMERS CERTAINTY FOR THE TERM OF THEIR LONG-TERM AGREEMENT?

A. Although it is reasonable for establishing a cap, setting the rate equal to Duke's incremental ancillary services cost would be inappropriate for several reasons. First, the higher cost is caused by all intermittent resources, not just new Sellers. Collection of incremental cost would result in preferential pricing for the first entrants while shifting cost recovery to new Sellers. This is equivalent to only charging generation cost to new retail customers that cause the need for a new generator while allowing all existing customers to benefit from greater resources, which is potentially discriminatory and inconsistent with average-cost ratemaking principles. Second, collection of incremental cost requires creation of vintage years for each participant, creating an administrative burden as projects get delayed or expiring projects renew sales under new agreements. It is quite possible that the average rate will never exceed the cap rate, thereby avoiding a need for vintage rates by applying the cap. Finally, adopting a rate based upon incremental cost fixes the rate for the long-term contract term and fails to recognize that ancillary services costs change over time. Collection of average costs eliminates these concerns and ensures that Sellers causing the ancillary services cost to be incurred properly pay the costs, thereby avoiding a cost shift to retail customers.

Q. SHOULD THE PROPOSED CHARGE APPLY TO BOTH EXISTING AND NEW INTERMITTENT GENERATION?

A. As previously noted, the Companies are only proposing to apply the proposed Integration Services Charge to solar photovoltaic eligible QFs that either establish a Legally Enforceable Obligation or renew, or otherwise extend, a

Purchased Power Agreement ("PPA") on or after November 1, 2018. This includes all Sellers served under Variable rates. While the Companies' tariffs allow updates to all terms, conditions and rates exclusive of fixed long-term energy and capacity rates upon approval of the Commission, the Companies recognize that Sellers paid under long-term rates could not have considered this charge at the time they originally entered into the PPA and therefore might be disadvantaged by this new charge. By delaying implementation until their current PPA expires and is subsequently renewed, QF Sellers are protected from immediately being subject to the new charge while also ensuring that they will eventually be responsible for these increased costs if they continue to sell their generation output. Until their current term expires, any increased ancillary services cost would be borne by retail customers.

Q. IS RECOVERY OF THE INTEGRATION SERVICES CHARGE FROM PURCHASED POWER CUSTOMERS CONSISTENT WITH SOUND RATEMAKING PRINCIPLES?

A. Yes. Inclusion of the Integration Services Charge in the Purchased Power Schedule PP is consistent with cost causation principles and minimizes cost shifting and subsidization by non-participants.

Q. DOES THE STIPULATION ALSO RECOGNIZE INNOVATIVE SOLAR GENERATORS THAT CAN DEMONSTRATE THE CAPABILITY TO REDUCE OR ELIMINATE ADDITIONAL ANCILLARY SERVICE REQUIREMENTS PARTIALLY OR COMPLETELY?

A. Yes. As further discussed by Witness Snider, the Stipulation provides that a solar generator that can demonstrate its capability of operating in a manner that materially reduces or eliminates the need for additional ancillary service requirements (as reasonably determined by the Companies) may reduce or eliminate the applicability of the Integration Services Charge. This capability could be demonstrated through inclusion of energy storage devices, agreeing to a dispatchable purchase contract, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generators.

Q. WOULD A SOLAR QF CONTRACTING TO SELL UNDER SCHEDULE PP BE ALLOWED TO REDUCE OR AVOID THE SOLAR INTEGRATION SERVICES CHARGE?

A. No. QFs contracting to sell under Schedule PP are "must take" and may only be curtailed during system emergencies. In addition to demonstrating its capability to operate in a manner that materially reduces or eliminates the need for additional ancillary service requirements, the Stipulation provides that solar QFs seeking to reduce or eliminate the applicability of the Integration Services Charge must also contractually agree to operate their solar generating facilities to meet operating requirements, as reasonably determined by Duke to be required to reduce or eliminate the need for additional ancillary services. These requirements would be established through a negotiated PPA and would prescribe terms and conditions governing the capacity of the energy storage facility, operational control and performance requirements, monitoring of the facility's operations, as well as remedies for failure to comply. Again, these provisions would be established through a negotiated PPA and not through Schedule PP.

Q. **IS IT YOUR VIEW THAT THE STIPULATION IS THE RESULT OF GOOD FAITH NEGOTIATIONS BETWEEN THE COMPANIES AND THE PUBLIC STAFF?**

A. Yes.

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

A. Yes.

235

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	))))))	**REBUTTAL TESTIMONY OF STEVEN B. WHEELER FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Steven B. Wheeler, P.E., and my business address is 411 Fayetteville Street, Raleigh, North Carolina 27601.

Q. **HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?**

A. Yes. I previously filed direct testimony supporting Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP") (together, the "Companies" or "Duke") proposed Integration Services Charge rate design on May 21, 2019.

Q. **PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.**

A. My testimony addresses concerns raised by North Carolina Sustainable Energy Association ("NCSEA") Witnesses R. Thomas Beach and Carson Harkrader and Southern Alliance for Clean Energy ("SACE") Witness Brendan Kirby contesting various aspects of the rate design recommended for the Integration Services Charge, as presented in my direct testimony and in the Solar Integration Services Charge Stipulation ("SISC Stipulation") between the Companies and the Public Staff.

Q. **ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL TESTIMONY?**

A. No.

Q. PLEASE REINTRODUCE THE PURPOSE OF THE INTEGRATION SERVICES CHARGE.

A. As explained more fully in my direct testimony and the direct testimony of Duke Witnesses Glen A. Snider and Nick Wintermantel of Astrapé Consulting, the Integration Services Charge recovers the Companies' respective cost for increased operating reserves necessitated by the intermittent nature of solar generation. The Integration Services Charge rate included in Schedule PP is set based upon the "average cost" of these additional operating reserves at DEC's and DEP's "Existing plus Transition" level of solar penetrations, as determined in the Astrapé Solar Ancillary Services Study ("Astrapé Study"). My testimony addresses how using the average ancillary services costs to develop the Integration Services Charge rate is consistent with the traditional ratemaking principle of cost causation, properly assigns the cost to the solar QF generators causing the increased ancillary services cost to be incurred, and is intended to avoid shifting these costs to the general body of customers.

Q. IS DUKE PROPOSING TO APPLY THE INTEGRATION SERVICES CHARGE TO ALL SOLAR GENERATORS?

A. No. As I explained in my direct testimony, the Integration Services Charge is proposed to only apply prospectively as of this Sub 158 proceeding. This means the charge will apply to QFs that either establish a new Legally Enforceable Obligation or otherwise enter into a new Purchase Power Agreement ("PPA") on or after November 1, 2018. Even though this cost is generally caused by all uncontrolled intermittent generators, Duke has proposed to not apply this charge retrospectively to earlier QFs, since the Integration Services Charge cost was not known at the time those QFs executed PPAs. Fixing a rate that charges average costs but excludes all pre-existing QF PPAs necessarily results in only partial recovery of the costs being incurred in the near term, and results in some subsidization of solar QFs by the general body of customers. However, all solar QFs that prospectively enter a new PPA will be subject to the Integration Services Charge, including QFs with expiring PPAs who opt to enter into a new PPA with the Companies. The Companies believe this approach of exempting solar generators that committed to sell their output to Duke prior to November 1, 2018, is reasonable based upon current circumstances. Additionally, the Public Staff has agreed with this approach as exemplified by Section II.B of the SISC Stipulation.

Q. WHAT STEPS HAVE BEEN TAKEN TO MITIGATE THE IMPACT OF BIENNIALLY UPDATING THE AVERAGE INTEGRATION SERVICES CHARGE IN NEW PPAS?

A. The SISC Stipulation memorializes Duke's acceptance of the Public Staff's recommendation to include a cap or maximum rate that can apply to PPAs executed under Sub 158 or future biennial vintages of solar PPAs. The cap will offer solar generators financial protection against increases in the Integration Services Charge over time during their initial contract term.

As identified by Public Staff Witness Jeffrey T. Thomas, the Public Staff initially proposed to either charge new solar generators the higher incremental level of solar integration costs and to eliminate the biennial refresh or, alternatively, to charge solar generators the average Integration Services Charge to be updated biennially in future avoided cost proceedings, but to also implement a reasonable cap on the amount by which the solar Integration Services Charge could change to provide certainty to QFs.[1]

Section IV and V of the Stipulation memorializes Duke's and the Public Staff's agreement that it is appropriate to fix the average Integration Services Charge to be updated biennially, while Section VI of the Stipulation provides that a cap on future increases to the Integration Services Charge shall be set at the incremental or marginal ancillary services cost rate for the last 100 MW of solar generation forecasted to be installed during the biennial vintage period under the Companies' biennial Integrated Resource Plans ("IRPs"). Since these costs are caused by all intermittent generation, the Companies recommend that they be recovered via an average rate to ensure that the generator will not shift these costs to the general body of customers. In conjunction with this average rate, the use of a marginal cost-based rate cap offers protection for the generator against unlimited changes to the cost during the QF's contract term. While the application of the rate cap could result in subsidization of the cost by retail customers in the future, I believe this approach is fair to all parties and places minimal risk on ratepayers whose possible overpayment to QFs can be addressed where an existing QF opts to enter into a new PPA upon expiration of its original agreement.

[1] Public Staff Thomas Direct Testimony, at 17.

Q. DO YOU AGREE WITH NCSEA WITNESS BEACH'S RECOMMENDATION THAT THE INTEGRATION SERVICES CHARGE BE CAPPED AT THE AVERAGE COST FOR THE CURRENT TRANCHE OF SOLAR STUDIED?

A. No. Mr. Beach testifies that if the North Carolina Utilities Commission adopts the Integration Services Charge, "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."[2] This recommendation is inappropriate and would effectively place the "cap" in the same place as the initial charge.

It is important to first recognize that Duke and the Public Staff are not recommending that the monthly Integration Services Charge rate be set at the higher "incremental" or marginal cost level because the cost is caused by all uncontrolled intermittent generators and will eventually be paid by all intermittent generators as the rate is phased-in with newly-executed PPAs. However, the cost impact experienced during the biennial period as new intermittent generation is added up to the point in time when the Companies' ancillary services costs are again reviewed in the next biennial proceeding is equivalent to the marginal or "incremental" ancillary services cost associated with this added generation. The Companies believe that collection of an average cost rate is a fair balance of generator and ratepayer interests and, additionally, that the marginal cost rate cap mitigates financial risk for the generator against undue cost impacts in the future.

[2] NCSEA Beach Direct Testimony, at 6.

Q. DO YOU AGREE WITH SACE WITNESS KIRBY THAT THE RATE CAP BEING SET AT MARGINAL COST IS INCONSISTENT WITH THE MONTHLY RATE BEING SET AT AVERAGE COST?

A. No. Witness Kirby overlooks the fact that the cap is only intended to offer QFs reasonable protection against unexpected increases to the Integration Services Charge over time. The marginal cost reflects the actual cost impact of the new intermittent generator on system costs; therefore, it offers ratepayers protection against undue costs incurred to integrate the intermittent generator into the grid. The monthly Integration Services Charge rate is set at an average cost because, eventually, all intermittent generators will be assessed the Integration Services Charge. Once the average rate applies to all intermittent generators, the increased cost of operating reserves will be fully recovered, and the current subsidization by retail customers thereby eliminated.

Q. DOES WITNESS BEACH SUPPORT THE STIPULATION PROVISIONS THAT PROVIDE THAT NO CHARGE APPLY TO EXISTING GENERATORS AND THOSE NEW GENERATORS THAT DEMONSTRATE THAT INCREASED OPERATING RESERVES ARE NOT REQUIRED?

A. Yes. Witness Beach supports not applying the charge to existing PPAs executed under rates approved prior to the current Sub 158 proceeding and agrees with not applying the charge if the generator demonstrates by using physical energy storage, contractual dispatch capabilities, or other innovative mechanisms that the generation is not impacting operating reserve requirements.[3]

Q. NCSEA WITNESS HARKRADER EXPRESSES CONCERN[4] WITH A LACK OF SPECIFICITY REGARDING THE PRECISE PARAMETERS THAT WOULD ALLOW THE INTEGRATION SERVICES CHARGE TO BE WAIVED. IS THIS A VALID CRITICISM?

A. No, not in my opinion. The Company's intent is to apply the charge to generators causing the cost to be incurred. This is one of the reasons why it is applied only to intermittent solar generators because studies to date indicated that these costs are only caused by these generators. The installation of energy storage devices alone won't eliminate the cost impact; therefore, the QF would need to provide the equipment configuration and intended operating schemes for assessment before the Company can concur that the charge isn't applicable. This would be addressed in a negotiated PPA with the generator.

As discussed further by Duke Witness David Johnson, Duke intends to work with the Public Staff and solar QF generators proposing to enter into a negotiated PPA to establish reasonable and appropriate design specification and operating protocols that would enable the solar generator to operate in a manner that materially reduces or eliminates the intermittency of the facility's generation and the need for additional ancillary services requirements. Upon the solar generator contractually agreeing to operate its facility in a manner that

[3] NCSEA Beach Direct Testimony, at 21.
[4] NCSEA Harkrader Direct Testimony, at 14-15.

mitigates the facility's intermittency, the negotiated PPA would not impose the Integration Services Charge.

Q. PLEASE ADDRESS NCSEA WITNESS HARKRADER'S RECOMMENDATION[5] THAT THE INTEGRATION SERVICES CHARGE SHOULD NOT APPLY TO EXISTING SOLAR GENERATORS AT THE TIME OF CONTRACT RENEWAL.

A. NCSEA Witness Harkrader recommends that existing solar QFs that entered into PPAs prior to this current biennial Sub 158 vintage should not be subject to the Integration Services Charge at the time the QF enters into a new PPA. She asserts that these QFs were constructed based upon "business circumstances that existed at the time of their construction," and requiring these operating QFs to pay the Integration Services Charge would effectively "chang[e] the rules of the road once a vehicle is halfway to its destination."[6]

I disagree with her position and her analogy. The costs recovered under the Integration Services Charge are caused by all intermittent generators. The Companies are only recommending that the charge not apply to existing QFs because the charge was not quantified at the time the QF committed to sell to the Companies over the specified term of commitment established in the PPA. However, there is no obligation or commitment from the QF to sell its generation output to the host utility once the initial PPA expires; therefore, all changed cost parameters, including the Integration Services Charge, updated

[5] *Id.* at 15-17.
[6] NCSEA Harkrader Direct Testimony, at 17.

avoided cost rates, and updated rate designs, should be evaluated by the QF to determine whether to enter into a new PPA and sell the Companies its full output from the facility. To exempt the renewing QF from payment responsibilities for the cost recovered in the Integration Services Charge results in continued subsidization of the QF by the general body of ratepayers and is therefore inappropriate.

Q. WILL OPERATING QFS BE ALLOWED TO BECOME CONTROLLED SOLAR GENERATORS AND TO AVOID THE INTEGRATION SERVICES CHARGE UNDER THE SISC STIPULATION?

A. Yes, and I think this is an important point that shows the unreasonableness of Witness Harkrader's recommendation. As discussed above, new QFs can make investments to design and operate their facilities as controlled solar generators in order to materially reduce or eliminate the intermittency of their output that causes the increased ancillary services cost and thereby avoid the Integration Services Charge under Section II.A of the SISC Stipulation. QFs that committed to sell to Duke prior to November 1, 2018, and which are effectively grandfathered under the SISC Stipulation during the term of their current PPA, will have the same opportunity at the end of their contract term to consider incremental investments to their facility to avoid the Integration Services Charge. These operating QFs are already being subsidized by the general body of ratepayers for the remaining term of their current PPAs. However, at the conclusion of their current commitment to sell power to the Companies, these

QFs should be required to either pay the costs that they are causing or to make investments to avoid the costs, similar to all other solar generators.

Q. WITNESS HARKRADER ALSO OPPOSES THE TWO-YEAR UPDATE OF THE INTEGRATION SERVICES CHARGE BECAUSE IT CREATES UNCERTAINTY, MAKING QF PROJECTS MORE DIFFICULT TO FINANCE. PLEASE RESPOND.

A. The Companies addressed this concern by including a rate cap in its rate design to ensure that the financial exposure to the Integration Services Charge is limited in the future. Routinely updating the Integration Services Charge allows it to more closely align with the actual cost being incurred by the Companies and, therefore, minimizes subsidization of intermittent generators in retail rates by retail customers. Duke has consistently reviewed its cost and added or adjusted rates when appropriate to better reflect cost of service and minimize subsidization. The Companies recommend that the Integration Services Charge be treated in this same manner and should be reviewed and adjusted upward or downward every two years as avoided costs are reviewed.

Q. DO YOU BELIEVE THAT THE INTEGRATION SERVICES CHARGE AND SUPPORTING SISC STIPULATION IS REASONABLE, AND SHOULD BE APPROVED BY THE COMMISSION?

A. Yes. The Integration Services Charge is a reasonable and necessary charge that fairly recovers the increased ancillary services costs caused by intermittent solar generators that customers would otherwise pay.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BY MS. FENTRESS:

Q Mr. Wheeler, do you have a copy of the -- do you have a summary of your testimony?

A Yes, I do.

Q Would you please present your summary for the Commission?

A My direct testimony supports the Companies' proposal to update their purchase power schedules and avoided cost rates and associated terms and conditions, as well as the proposed integration services charge, to recover costs for increased operating reserves necessitated by intermittent solar generation. Specifically, I explain the proposed integration services charge rate design and support the Stipulation agreement between Duke and the Public Staff, filed on May 21, 2019 in this docket, hereinafter Stipulation, that establishes a rate design to recover the increased cost created by intermittent solar generation.

The proposed integration services charge, hereinafter Charge, is based on the results of the Astrapé study of how the integration of variable, intermittent generation affects ancillary services on the Duke system. Because the study found that the increased ancillary services cost impact was unique to intermittent generation, Duke proposes an integration services charge only -- applies only to solar facilities that either establish a legally enforceable obligation or execute a purchased power agreement, or PPA, after expiration of an existing PPA or otherwise, on and after November 1st, 2018. Duke recognizes that QFs paid under earlier long-term rates would not have considered this Charge at the time they originally entered into the -- their PPAs. By delaying implementation of the Charge until November 1st, 2018 or after, QFs are protected from immediately being subjected to the new charge during the duration of their existing PPAs, but not after expiration of those PPAs if they elect to continue to sell generation output to the Companies through PPAs entered into after November 1st, 2018.

The Public Staff and Duke engaged in discussions on the Charge and its rate design, and through those discussions reached consensus, as reflected in the Stipulation. The rate design for the integration services charge, as outlined in the Stipulation, reflects the current average cost of ancillary services caused by the integration of intermittent generation. This average rate will be reviewed and adjusted in each biennial avoided cost proceeding and will apply to all new and existing QFs subject to the Charge. The design caps the Charge based on the incremental cost identified in the Astrapé study. This cap offers QFs financial protection against increases in the Charge over time during the initial contract term. This cap will apply to QFs based on their vintage of long-term fixed rates. Fixing a rate that charges average cost, but excludes preexisting QF PPAs, results in only partial recovery of cost incurred in the near term and results in some subsidization of solar QFs by Duke's retail customers.

Innovative solar QFs have the option to reduce or eliminate the integration services charge if they (1) demonstrate the capability to operate in a manner that materially reduces or eliminates the need for ancillary service requirements and (2) enter into a negotiated PPA that prescribes their planned operating scheme. This option will not apply, however, to solar QFs contracting to sell under Schedule PP, which is a must-take and can only be curtailed during system emergencies.

My rebuttal testimony addresses concerns raised by NCSEA Witnesses Beach and Harkrader and SACE Witness Kirby contesting various aspects of the integration services charge rate design. NCSEA Witness Beach recommends the cost cap be the same as the average integration cost for this tranche of solar studied. The Companies believe that an incremental cost rate cap mitigates the financial risk for QFs against undue cost impacts in the future. SACE Witness Kirby contends that setting the cap at incremental cost is inconsistent with the monthly rate set at average cost. The Companies' position is that incremental cost reflects the actual cost impact of new intermittent generation (sic) on system costs and, thus, offers some retail customer protection; the monthly rate is set at an average cost because eventually all intermittent generators will be assessed the Charge. Once the average rate applies to all intermittent generators, the increased cost of operating reserves will be fully recovered and the current subsidization by retail customers eliminated.

With respect to concerns about the lack of specific parameters for -- for waiver of the integration services charge, I respond that the Companies intend to apply the Charge to generators causing the cost the Companies incur. The installation of energy storage devices alone will not eliminate the cost impact. The Companies intend to work with the Public Staff and solar QFs proposing to enter into negotiated PPAs to establish reasonable design specifications and operating protocols that will enable solar QFs to operate in a manner that reduces or eliminates the intermittency of the facility's generation and the need for additional ancillary service requirements.

I further explain that the Charge should apply to both existing and new solar QFs if they enter into a new PPA after November 1, 2018. The costs recovered by the Charge are caused by all intermittent generators. To exempt an existing QF seeking to enter into a new PPA after November 1, 2018, after expiration of a previous PPA, would result in continued subsidization of the QF by Duke's retail customers and is, thus, inappropriate. At the conclusion of their current commitment to sell power to the Companies, existing QFs have the option to make investments to avoid these costs, similar to other solar generators. With respect to concerns about the two-year update of the Charge, I respond that the Companies believe that routine updates of the Charge will align it more closely with the actual costs being incurred by the Companies, and that a biennial review is appropriate. The proposed integration services charge and supporting Stipulation between the Companies and the Public Staff are reasonable and should be approved by the Commission.

In my portions of the joint supplemental rebuttal testimony with Glen Snider and David Johnson, I respond to Ecoplexus Witness Wallace's contention that measuring energy storage system output through a DC data logger is technically feasible. My testimony explains why the mere existence of a DC metering device fails to resolve all issues created when a material alteration of a facility creates multiple classes of generation output. These issues involve the installation of Company metering within a customer's electrical system, differing electrical safety standards, the lack of ANSI standards, DC measurement conflicts with AC billing, and the cost impact of offering new non--- nonstandard equipment for a limited number of applicants. A much simpler approach that is consistent with all other utility metering practices is to require measure of the energy storage device output after it has been converted to DC and is delivered to the utility grid.

This concludes my summary.

Q Thank you. And now we'll proceed with Mr. Johnson. Mr. Johnson, can you please state your name and business address for the record?

A (Johnson) Yes. My name is David Johnson, and my business address is 400 South Tryon in Charlotte.

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

A I'm employed by Duke Energy Corporation, and I'm the Director of Business Development and Compli--- Compliance.

Q Did you cause to be prefiled in this docket on May 21st, 2019, 13 pages of direct testimony in question and answer form?

A Yes, I did.

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

A No.

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 And did you also cause to be prefiled in this docket on July 3rd, 2019, 17 pages of rebuttal testimony in question and answer form?

A Yes, I did.

Q And do you have any changes or corrections to that rebuttal testimony?

A No, I don't.

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

A Yes.

Q Did you also cause to be prefiled in this docket on July 11th, 2019, along with Mr. Snider and Mr. Wheeler, 37 pages of joint rebuttal supplemental testimony in question and answer form?

A Yes, I did.

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

A No.

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

A Yes.

MS. FENTRESS: Madam Chair, at this time I would move that the prefiled direct, rebuttal, and joint rebuttal supplemental testimonies of Mr. Johnson be copied into the record as if given orally from the stand.

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

(Whereupon, the prefiled direct and rebuttal testimony of David B. Johnson was copied into the record as if given orally from the stand. The joint supplemental rebuttal testimony was copied into the record on pages 173 through 209.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of:	)	**DIRECT TESTIMONY OF**
	)	**DAVID B. JOHNSON**
Biennial Determination of Avoided Cost	)	**ON BEHALF OF DUKE**
Rates for Electric Utility Purchases from	)	**ENERGY CAROLINAS, LLC**
Qualifying Facilities - 2018	)	**AND DUKE ENERGY**
	)	**PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David B. Johnson. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. WHAT IS YOUR POSITION WITH DUKE ENERGY CORPORATION?

A. I am employed by Duke Energy Corporation ("Duke Energy") as Director of Business Development and Compliance.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. My educational background includes a Bachelor of Science in Civil Engineering from the University of Tennessee. With respect to professional experience, I have been in the utility industry for over 38 years. I started as an associate Design Engineer in the Design Engineering Department at Duke Power in 1980. From 1991-1995, I worked for Duke Energy's affiliate companies Duke/Fluor Daniel and Duke Engineering & Services, Inc. In 1996, I worked in the initial Duke Power Trading Group in Charlotte, North Carolina, where I focused on marketing and business development and management until 2006. From 2006 to 2017, I worked as a Business Development Manager and Director in the Duke Energy wholesale and renewable energy areas. I began my current role in late 2017.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DUKE ENERGY.

A. I am responsible for wholesale Power Purchase Agreements ("PPA") that Duke Energy enters into with third-party suppliers. These include PPAs that Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies" or "Duke") enter into with Qualifying Facilities ("QFs"), renewable PPAs to comply with North Carolina's Renewable Energy and Energy Efficiency Portfolio ("REPS") standard, Competitive Procurement of Renewable Energy ("CPRE") PPAs, and conventional (non-renewable) PPAs. I have responsibility for the negotiation and execution of these PPAs, as well as the ongoing management of all executed PPAs. In addition, I am responsible for Duke's compliance with the REPS and the CPRE Program.

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

A. Yes. I have previously testified once before the Commission on behalf of Duke Power in the late 1990s.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the proposed modifications to the Companies' Standard PPA available to QFs eligible for Schedule PP and the standard Terms and Conditions for the Purchase of Electric Power ("Terms and Conditions"), as directed by the Commission's April 24, 2019 *Order Scheduling Evidentiary Hearing and Establishing Procedural*

Schedule issued in this proceeding. Specifically, my testimony supports the Companies' proposed modifications to the Schedule PP PPAs and Terms and Conditions to more clearly address the requirements for utility approval prior to a QF owner making "Material Alterations" to a QF generating Facility selling power under Schedule PP. I am also supporting the Companies' proposed Energy Storage Protocols applicable to standard offer QFs selling under Schedule PP, as previously filed as Exhibit 6 to the Companies' reply comments on March 27, 2019 ("Reply Comments").

Q. **ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?**

A. No. The Companies are not proposing additional modification to the Schedule PP PPAs, Terms and Conditions, and Energy Storage Protocols filed as Exhibits 4, 5, and 6 to the Companies' Reply Comments. Therefore, I am not refiling those Exhibits, and my testimony incorporates them by reference.

Q. **PLEASE DISCUSS WHY THE COMPANIES HAVE PROPOSED CHANGES TO THEIR STANDARD OFFER PPA AND TERMS AND CONDITIONS TO MORE CLEARLY ADDRESS PROPOSALS BY QF OWNERS TO MATERIALLY ALTER OPERATING QF GENERATING FACILITIES.**

A. Since the Commission last reviewed the Companies' avoided cost tariffs in 2016, the Companies have received multiple inquiries from solar developers requesting clarification as to what alterations can and cannot be made to operating QF generating Facilities within the terms of their existing PPAs. Proposals have included replacing existing solar photovoltaic panels with greater MW_{DC} capacity panels, known as "over-paneling," or proposing to co-locate battery storage at a QF generating Facility in order to either increase their energy output or to shift their energy output from lower rate off-peak hours to higher rate on-peak hours.

In response, the Companies are clarifying certain provisions of DEC's and DEP's standard Schedule PP PPA and Terms and Conditions addressing the Companies' rights to require prior approvals of material alterations to QF generating Facilities operating under existing PPAs.

As highlighted in the Companies' Joint Initial Statement[1] and discussed in greater detail by Witness Glen A. Snider, the avoided cost rates approved in earlier avoided cost proceedings now significantly exceed the Companies' current and forecasted avoided costs. Today, over 3,600 MW of solar capacity (approximately 500 solar QF generating Facilities) have committed to sell to the Companies at significantly higher and now out-of-date avoided cost rates approved in the Sub 127 (2010), Sub 136 (2012) and Sub 140 (2014) proceedings. Any modifications to these contracted QF generating Facilities to increase their generator size (MW_{AC}), increase their capability to produce energy in more hours of the day (MW_{DC}), or to shift their energy production at these outdated and now-excessive avoided cost

[1] DEC and DEP Joint Initial Statement, at 6-9, (filed Nov. 1, 2018) ("Joint Initial Statement").

rates will increase future over-payments to QFs in excess of the Companies' actual avoided costs.

Due to these current economic and regulatory circumstances facing Duke and our customers, modifications to the standard PPA and Terms and Conditions are necessary and appropriate to prevent exacerbation of the Companies' current financial obligations to QFs and, most importantly, to mitigate increased future over-payment to QFs by our customers.

Q. PLEASE DISCUSS THE COMPANIES' PROPOSED MODIFICATIONS TO THE SCHEDULE PP PPA AND TERMS AND CONDITIONS TO ADDRESS THESE CONCERNS.

A. The Companies are making several clarifying modifications to the Schedule PP PPA and Terms and Conditions to address these concerns. As discussed in the Companies' Joint Initial Statement,[2] Duke initially proposed revisions to the definition of Facility in the Schedule PP PPA and to Sections 1.i (Company's Right to Terminate or Suspend Agreement); 4.a and 4.d (Contract Capacity); and 6.b (Increase in Contract Capacity) of the Schedule PP Terms and Conditions.

The Companies' Reply Comments supported additional revisions and refinements to the proposed Terms and Conditions to address the initial comments filed by the Public Staff and the North Carolina Sustainable Energy Association ("NCSEA"), including clarifying whether non-material

[2] *See* DEC and DEP Reply Comments, at 137-140 (filed Mar. 27, 2019) ("Reply Comments"); Joint Initial Statement, at Exhibit 3 (Power Purchase Agreement), at 1, 2 and Exhibit 4 (Terms and Conditions), at 2, 4-7.

modifications to a Facility that result in the QF producing energy in excess of the estimated annual energy production contained in the PPA would allow the utility to terminate the QF's PPA. For example, NCSEA argued that the Companies' initial proposal, without further clarification, could be interpreted to require QFs to seek approval from the utility when making necessary repairs or replacements to their Facilities in the normal course of their operations.[3]

Recognizing these parties' concerns, the Companies added a defined term for "Material Alteration" to the Terms and Conditions to more clearly describe what changes or alterations to an operating QF generating Facility selling under a pre-existing PPA would trigger the utility's right to terminate the PPA where the QF did not seek prior authorization from the utility before making the alteration.

Q. PLEASE EXPLAIN WHAT DUKE MEANS BY "MATERIAL ALTERATION."

A. As explained above, the Companies have introduced the term "Material Alteration" to the standard offer PPA and Terms and Conditions to better address the impact of a material change to an existing QF "Facility" on the commercial terms of the Agreement. The PPA establishes the commercial terms pursuant to which the Companies will purchase the output from the Facility, including the agreed-upon "Contract Capacity" (100% of the Facility's output), and establishes the contract price (as specified in

[3] NCSEA Initial Comments, at 52 (filed Feb. 12, 2019).

Schedule PP) to be paid to the QF. The term "Material Alteration" is defined as follows:

> "Material Alteration" as used in this Agreement shall mean a modification to the Facility which renders the Facility description specified in this Agreement inaccurate in any material sense as determined by Company in a commercially reasonable manner including, without limitation, (i) the addition of a Storage Resource; (ii) a modification which results in an increase to the Contract Capacity, Nameplate Capacity (in AC or DC), generating capacity (or similar term used in the Agreement) or the estimated annual energy production of the Facility (the "Existing Capacity"), or (iii) a modification which results in a decrease to the Existing Capacity by more than five (5) percent. Notwithstanding the foregoing, the repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%) shall not be considered a Material Alteration.

This term clarifies that QF owners may not modify the originally-certificated Facility that entered into the PPA and has been selling power at the Companies' pre-existing avoided cost rates in such a way as to increase the Existing Capacity of the generating Facility or to reduce the Existing Capacity by more than 5%. This would include the addition of a Storage Resource, as that term is now defined in the Terms and Conditions. Duke has also clarified that material changes to existing Facilities will be evaluated in a commercially reasonable manner.

Q. HAVE THE COMPANIES ADDRESSED CONCERNS REGARDING QFs' ABILITY TO REPAIR OR REPLACE DAMAGED FACILITY COMPONENTS SUCH AS SOLAR PANELS, INVERTERS, ETC. WITHOUT BEING IN DEFAULT UNDER THE PPA AND TERMS AND CONDITIONS FOR MAKING A MATERIAL ALTERATION?

A. Yes. As provided in the new Material Alteration definition, the repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%), shall not be considered a Material Alteration and can be undertaken by the QF owner in the normal course of business without obtaining Duke's prior consent.

Q. DO YOU BELIEVE DUKE'S PROPOSED MODIFICATIONS TO THE TERMS AND CONDITIONS ARE REASONABLE FROM A CONTRACTUAL PERSPECTIVE?

A. Yes. Just as it would be unreasonable for Duke to respond to declining avoided cost rates by unilaterally adjusting the fixed price paid to a QF, or by unilaterally reducing the amount of power purchased from the QF, it is similarly unreasonable for a QF to materially alter its generating Facility to sell more energy at now-excessive avoided cost rates or to shift its generation output into legacy on-peak hours no longer aligning with Duke's highest marginal cost hours. Duke's proposal is reasonable and aligns with the well-established principle that the rights and obligations of parties to a binding contract are determined at the time the contract is executed, and cannot be materially modified by one party without prior consent of the other party during the term of the contract.

Q. ARE THERE ANY OTHER PROPOSED MODIFICATIONS OR ADDITIONS TO THE COMPANIES' SCHEDULE PP TERMS AND CONDITIONS THAT YOU WOULD SPECIFICALLY LIKE TO ADDRESS?

A. Yes. The Companies have modified Section 2.(b) of the Terms and Conditions to provide that Sellers should operate their Facilities in compliance with instructions provided by the Companies' system operators, including any energy storage protocols:

> Seller shall operate its Facility in compliance with all: (i) system operator instructions provided by Company, including any energy storage protocols provided if applicable; (ii) applicable operating guidelines established by the North American Electric Reliability Corporation ("NERC"); and (iii) the SERC Reliability Corporation ("SERC") or any successor thereto.

In response to comments filed in the proceeding, the Companies have incorporated a definition of system operator instruction as well as proposed Energy Storage Protocols specific to QFs contracting to sell power under Schedule PP.

Q. PLEASE DISCUSS THE PURPOSE OF THE ADDITION TO EXPRESSLY REQUIRE STANDARD OFFER QFs TO COMPLY WITH SYSTEM OPERATOR INSTRUCTIONS.

A. As discussed in the Companies' Reply Comments, these system operator instructions are designed to effectuate the curtailment rights provided for

266

under PURPA to respond to system emergencies, as expressly recognized by the Commission in the *2016 Sub 148 Order*.[4] This provision is not intended to provide the Companies additional rights outside of the PPA to curtail QFs. Instead, these system operator instructions memorialize the Companies' pre-existing rights and obligations to curtail QFs in a non-discriminatory manner where necessary to respond to an emergency condition or force majeure event in order to maintain safe and reliable operation of the Companies' system.

Q. PLEASE ADDRESS THE REQUIREMENT FOR STANDARD OFFER QFs TO COMPLY WITH ENERGY STORAGE PROTOCOLS.

A. As discussed in the Companies' Reply Comments, Duke has developed operating protocols applicable to standard offer QFs proposing to co-locate energy storage and has required QFs to agree to operate their QF generating Facility in compliance with the agreed-upon terms under Section 2.(b) of the Terms and Conditions. These standardized operating procedures will establish how batteries co-located with QF generating Facilities are operated in parallel with the Companies' system and will help assure that QFs effectively manage the charging and discharge of stored energy in real-time such that variability and ramping characteristics of such Facilities are not materially more challenging for the System Operator than a comparable solar Facility operating without a co-located Storage Resource.

[4] Reply Comments, at 149-150.

Q. DO THE STORAGE PROTOCOLS APPLICABLE TO QFs SELLING UNDER SCHEDULE PP DIFFER FROM THE COMPANIES' STORAGE PROTOCOLS APPLICABLE TO LARGER GENERATING FACILITIES?

A. Yes. The Schedule PP storage protocols for smaller standard offer QFs are more streamlined and impose less rigorous technical operating requirements than the storage protocols applicable to larger generating facilities selling power under the CPRE Program or from larger QFs selling under negotiated avoided cost rates. For example, the ramp rate for the Storage Resource when the Facility is not generating is limited to no more than 10% of the Storage Resource's capacity on a per-minute basis in the Standard PPA Storage Protocols as compared to no more than 5% of the Facility's Nameplate Capacity for the CPRE Storage Protocols. Likewise, when the Facility is generating, the storage device is not allowed to increase the ramp rate of the Facility by more than 5% of the Storage Resource's capacity (MW) per-minute in relation to the output of the Facility alone, as compared to only 1% of the Facility's Nameplate Capacity (MW) per-minute in relation to the output from the Facility alone in the CPRE Storage Protocols. The Schedule PP Energy Storage Protocols also include a provision for the System Operator to waive this ramping limitation. Also for the Schedule PP Energy Storage Protocols, the Companies eliminated the day-ahead identification of the available bulk discharge windows as is required in the CPRE Storage Protocols, and introduced a levelized facility output approach during storage discharge to allow the developer to automate storage control logic while providing more predictable Facility operations for the System Operator.

Q. **DO THE COMPANIES AGREE TO FILE ANY MODIFICATIONS TO THESE ENERGY STORAGE PROTOCOLS WITH THE COMMISSION?**

A. Yes. The Companies propose to file any changes to these protocols in Docket No. E-100, Sub 148 (or another docket as directed by the Commission) similar to the Companies' curtailment protocols for QFs.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of:	)	**REBUTTAL TESTIMONY OF**
	)	**DAVID B. JOHNSON**
Biennial Determination of Avoided Cost	)	**ON BEHALF OF DUKE**
Rates for Electric Utility Purchases from	)	**ENERGY CAROLINAS, LLC**
Qualifying Facilities – 2018	)	**AND DUKE ENERGY**
	)	**PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David B. Johnson. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I previously filed direct testimony supporting the Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP") (together, the "Companies" or "Duke") proposed modifications to the Companies' Standard power purchase agreement ("PPA") available to qualifying facilities ("QFs") eligible for Schedule PP and the standard Terms and Conditions for the Purchase of Electric Power ("Terms and Conditions") on May 21, 2019.

Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony begins by providing an overview of, and support for, the Companies' proposed modifications to the standard Terms and Conditions, and responds to the Public Staff's testimony on the same. Section II of my rebuttal testimony details the Public Staff's general support for the Companies' proposed Schedule PP Energy Storage Protocols, and additionally responds to the Public Staff's comments regarding the Schedule PP Energy Storage Protocol applicability. In Section III, I respond to the Public Staff's recommendation that the Companies describe the process an existing QF seeking to enter into a new PPA for a new term would follow to contract to sell its output to the Companies at the time the QF's current PPA expires. The final section of my testimony responds to the Public Staff's revisions concerning NCUC Rules R8-64 and R8-71.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL TESTIMONY?

A. No. Based upon my review of the direct testimony filed by the Public Staff and intervenors, the Companies are not proposing any modifications to the Schedule PP PPAs, Terms and Conditions, and Energy Storage Protocols filed as Exhibits 4, 5, and 6 to the Companies' Reply Comments. Therefore, I am not refiling those Exhibits, and my rebuttal testimony incorporates them by reference.

I. STANDARD TERMS AND CONDITIONS

Q. PLEASE BRIEFLY SUMMARIZE DUKE'S PROPOSED MODIFICATIONS TO THE SCHEDULE PP PPA AND STANDARD TERMS AND CONDITIONS, AS SUPPORTED IN YOUR DIRECT TESTIMONY.

A. As described in my direct testimony and in the Companies' Reply Comments, Duke has proposed revisions to the definition of Facility in the Schedule PP PPA and to Sections 1.i (Company's Right to Terminate or Suspend Agreement); 4.a and 4.d (Contract Capacity of QF Facility); and 6.b (Increase in Contract Capacity) of the amended Schedule PP Terms and Conditions.

Additionally, the Companies have amended their proposed modifications to the Schedule PP PPA and Terms and Conditions to introduce the term "Material Alteration" to better address the impact of a material change to an existing QF generating facility on the commercial terms of the PPA. As I discussed previously in my direct testimony, the term "Material Alteration" was introduced by the Companies to address concerns raised by the Public Staff and NCSEA during the comment phase of this proceeding. Specifically, the Companies incorporated the defined term of "Material Alteration" to clarify what constitutes a material change to a QF generating facility that would trigger the utility's right to suspend its purchase obligation and/or to terminate the PPA where the QF had not first obtained consent to make the material change.

Last, the Companies have incorporated a definition of System Operator Instruction in Section 2.(b) of the Terms and Conditions and provided a proposed energy storage protocol in Section 5 and Exhibit A of Standard PP PPA. The Schedule PP Energy Storage Protocols are specifically applicable to smaller QFs with a design capacity of 1,000 kW or less contracting to sell power under Schedule PP rates where a QF proposes to integrate battery storage technology. As I explain in my direct testimony, these additions were also made in response to the Public Staff's and intervenors' recommendations in the comment phase of this proceeding.

Q. DID THE PUBLIC STAFF FILE TESTIMONY ADDRESSING DUKE'S PROPOSED MODIFICATIONS TO THE STANDARD TERMS AND CONDITIONS?

A. Yes. Public Staff Witness John. R Hinton expressed general support for Duke's proposed modifications to the standard Terms and Conditions, and noted that "the changes made by Duke appear to be responsive to the issues raised by the Public Staff and other intervenors."[1] Witness Hinton also emphasized that Duke should apply "a degree of reasonableness" in determining whether a QF's investment materially changes the output profile of the QF or not, in regards to equipment repairs and replacements.[2] Witness Hinton also states that any material alterations to a QF generator made without reconsideration of the QF's original interconnection study and originally-applicable avoided cost rates would be inappropriate.[3]

Q. DID OTHER INTERVENORS FILE TESTIMONY ADDRESSING DUKE'S PROPOSED MODIFICATIONS TO THE STANDARD TERMS AND CONDITIONS?

A. No. The five witnesses that pre-filed testimony on behalf of the North Carolina Sustainable Energy Association ("NCSEA") and the Southern Alliance for Clean Energy ("SACE") did not specifically address or take issue with the Companies' proposed modifications to the standard Terms

[1] Public Staff Hinton Direct Testimony, at 18.
[2] *Id.*
[3] *Id.*

and Conditions, as sponsored in Duke's Reply Comments and supported in my direct testimony.

Q. HOW DO THE COMPANIES RESPOND TO THE PUBLIC STAFF'S TESTIMONY REGARDING DUKE'S PROPOSED MODIFICATIONS TO THE STANDARD TERMS AND CONDITIONS?

A. As recognized by the Public Staff, the Companies have made good faith efforts prior to filing Reply Comments to amend their originally-proposed Standard Terms and Conditions to address concerns raised by the Public Staff's and other intervenors' initial comments. For example, as I previously highlighted in my direct testimony, the now-defined term "Material Alteration" provides that Duke will assess any proposed modifications to a QF generating facility in a commercially reasonable manner and expressly provides QF owners with contractual assurance that equipment at the facility (including solar panels) can be repaired or replaced with like-kind equipment during the term of the contract. Thus, the Companies' proposed modifications to the standard Terms and Conditions are reasonable and will enable QFs selling under Schedule PP to pursue commercially reasonable and efficient investments to operate and maintain their generating facility over the term of the contract. In light of the Public Staff's general support and non-opposition by other parties, Duke requests that the standard offer Terms and Conditions be approved.

II. ENERGY STORAGE PROTOCOLS

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE COMPANIES' PROPOSED ENERGY STORAGE PROTOCOLS.

A. As I explained in my direct testimony, Duke has developed standardized operating protocols specific to smaller standard offer QFs selling under Schedule PP that propose to integrate energy storage. These protocols establish how batteries integrated or co-located with QF generating facilities selling under Schedule PP will operate in parallel with the Companies' system. Compliance with the protocols will help assure that QFs effectively manage the charging and discharging of stored energy in real time such that variability and ramping characteristics of such facilities are not materially more challenging for the System Operator than a comparable solar facility operating without a co-located storage resource.

Q. HAVE THE COMPANIES PROPOSED MODIFICATIONS TO THE STANDARD OFFER TERMS AND CONDITIONS TO REQUIRE COMPLIANCE WITH THE ENERGY STORAGE PROTOCOLS?

A. Yes. Proposed Section 2.(b) of the standard Terms and Conditions requires QFs with energy storage selling under Schedule PP to operate their QF generating facility in compliance with the Schedule PP Energy Storage Protocols.

Q. HAS THE PUBLIC STAFF COMMENTED ON THE COMPANIES' PROPOSED STANDARD OFFER ENERGY STORAGE PROTOCOLS?

A. Yes. Public Staff Witness Jeffrey T. Thomas states that operational guidelines are appropriate to ensure that facilities integrating energy storage are operated in a safe, reliable and efficient manner, and testifies that Duke's proposed Energy Storage Protocols incorporate relevant factors for operation of energy storage facilities in parallel with the Duke system.[4] Witness Thomas also states that the Public Staff defers to Duke on how to best maintain system reliability, due to the complexity of the Companies' system and the necessity to consider the aggregate effect of potentially large quantities of third-party energy storage.[5] The Public Staff does not recommend any modifications to the Companies' standard offer Energy Storage Protocols as currently proposed.

Q. HOW DO YOU RESPOND TO WITNESS THOMAS' COMMENTS?

A. I agree with Witness Thomas. I would also highlight that when filing the Sub 158 Standard Offer PPA, it was Duke's intent to prescribe more flexible Energy Storage Protocols for small QFs selling under Schedule PP than for larger QFs not eligible for Schedule PP and selling under negotiated contracts, such as those for Tranche 1 of the Competitive Procurement of Renewable Energy ("CPRE") Program. In addition to the smaller size (and mitigated operational risk associated with Schedule PP facilities), the Companies' more flexible Schedule PP Energy Storage Protocols are also reflective of the new, more granular proposed avoided cost rate design

[4] Public Staff Thomas Direct Testimony, at 30-31.
[5] *Id.* at 31.

supported by Witness Glen A. Snider, which will also provide standard offer QFs more precise economic signals of when to discharge.

Q. DID ANY OTHER INTERVENORS RECOMMEND MODIFICATIONS OR OTHERWISE TAKE ISSUE WITH THE COMPANIES' STANDARD OFFER ENERGY STORAGE PROTOCOLS?

A. No. Other intervenors did not address the standard offer Energy Storage Protocols. Accordingly, I recommend the Schedule PP Energy Storage Protocols be approved, as reasonable and appropriate to support the safe and reliable parallel operation of smaller QF energy storage systems interconnected to the Duke system. As I highlighted in my direct testimony, Duke proposes to file any future changes to these protocols in this current avoided cost Docket No. E-100, Sub 158 (or another docket as directed by the Commission) similar to the Companies' curtailment protocols for QFs in Docket No. E-100, Sub 148.

Q. DID THE PUBLIC STAFF COMMENT ON ENERGY STORAGE REQUIREMENTS AND PROTOCOLS APPLICABLE TO QFS NOT ELIGIBLE FOR THE SCHEDULE PP STANDARD OFFER?

A. Yes. Public Staff Witness Thomas also commented on the potential future operating requirements for QFs proposing to avoid the Integration Services Charge under the Solar Integration Services Charge Stipulation ("SISC Stipulation") agreed to between Duke and the Public Staff and filed with the Commission on May 21, 2019. Specifically, Witness Thomas commented that operating battery storage in a manner that allows a QF to mitigate the intermittency and intra-hour volatility that causes the need for incremental ancillary services, such as using an energy storage device to "smooth" its output profile and to eliminate any unplanned fluctuations, would likely require deviation from the storage protocols applicable to standard offer QFs under Schedule PP.[6]

Q. HOW DO THE COMPANIES RESPOND TO THE PUBLIC STAFF'S COMMENT THAT THE STANDARD OFFER ENERGY STORAGE PROTOCOLS MAY NOT BE APPROPRIATE FOR LARGER QFS INELIGIBLE FOR SCHEDULE PP?

A. I agree with Witness Thomas that the operational requirements of the Schedule PP Energy Storage Protocols will likely need to be modified in the context of negotiated PPAs to enable "smoothing" functionalities that would mitigate the need for increased ancillary services. Duke Witness Snider further addresses how a solar + battery energy storage system has operational optionality to either smooth its output to mitigate intermittency and intra-hour volatility or to optimize its revenue through selling its maximum generating capability during peak- and premium-peak periods. This optionality can be considered in the context of negotiating a PPA with larger QFs not eligible for Schedule PP. Ultimately, Duke's objective is to establish reasonable protocols that allow the Companies' system operators

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[6] *Id.* at 31-32.

to effectively plan for and integrate these new technologies into system dispatch while maintaining system reliability.

Q. **HAVE THE COMPANIES DEVELOPED SPECIFIC DESIGN SPECIFICATIONS AND OPERATIONAL REQUIREMENTS FOR QFS SEEKING TO AVOID THE INTEGRATION SERVICES CHARGE AT THIS TIME?**

A. Not at this time. However, the Companies anticipate developing specific requirements in the coming months and will make them available to QF developers seeking to negotiate a PPA that proposes to integrate battery storage. Duke Witness Snider further addresses the operational considerations that the Companies plan to take into account where a QF proposes to integrate battery storage and to contractually commit to materially reduce or eliminate the need for Duke to incur additional ancillary service requirements under Section II.A of the SISC Stipulation.

Q. **PUBLIC STAFF WITNESS THOMAS ALSO COMMENTS THAT IT IS UNCLEAR WHETHER QFS BIDDING PROPOSALS INCORPORATING STORAGE INTO FUTURE TRANCHES OF THE CPRE PROGRAM WILL BE SUBJECT TO THE STANDARD OFFER ENERGY STORAGE PROTOCOLS. PLEASE RESPOND.**

A. As Public Staff Witness Thomas notes in his testimony, there have been ongoing discussions in the CPRE dockets and at the recent Technical Conference held by the Commission on May 23, 2019, concerning the Companies' energy storage protocols that would apply during Tranche 2 of

CPRE. These discussions have focused on updating the energy storage protocols used in Tranche 1. The update would include reducing operational restrictions such as ramp rate limits and scheduling provisions. It is envisioned at this time that the updated Tranche 2 energy storage protocols would be somewhat similar to the Schedule PP Energy Storage Protocols filed in this Sub 158 docket in light of the new, more granular rate design that will influence QF operations.

III. PROCESS FOR EXISTING QFS TO ENTER INTO NEW PPA

Q. PLEASE RESPOND TO PUBLIC STAFF WITNESS HINTON'S RECOMMENDATIONS THAT THE COMPANIES ADDRESS HOW AN EXISTING QF CAN ESTABLISH A NEW COMMITMENT TO SELL PRIOR TO THE TIME ITS CURRENT PPA EXPIRES.[7]

A. A QF seeking to enter into a new PPA for a future specified term may request a new PPA by submitting a new Notice of Commitment ("NOC") form to the Companies. To ensure that the QF will be paid reasonably accurate avoided cost rates at the time of delivery, the Companies do not accept requests to enter into a new PPA earlier than twelve months (one year) prior to the end of the QF's existing PPA term. Upon receipt of the request, Duke will provide the QF a fixed-rate quote for the term requested and a corresponding draft PPA. For negotiated PPAs, the term provided in the draft PPA will not exceed a five-year term, as provided for in N.C. Gen. Stat. § 62-156(c), and the forecasted avoided cost rates will be calculated

[7] Public Staff Hinton Direct Testimony, at 13.

281

based upon the Commission's currently approved avoided cost methodology.

Consistent with the standard prescribed by the Commission in the NOC form for negotiated PPAs, the QF must execute the newly-tendered PPA within six months of delivery by Duke. Unless this six month period for contract execution is extended per the terms of the NOC form, the commitment to sell under the NOC form as well as the fixed-rate price quote will expire at the end of the six month period.

Similarly, an existing QF eligible for the Companies' standard offer PPA pursuant to N.C. Gen. Stat. § 62-156(b)(1) would automatically have the right to enter into a new ten-year term PPA at the Companies' standard offer avoided cost rates applicable to new QFs as of the date the QF's current PPA is set to expire.

Q. DO YOU BELIEVE THE COMPANIES' POLICY FOR EXISTING QFS SEEKING TO ENTER INTO A NEW PPA FOR A SPECIFIED TERM IS REASONABLE?

A. Yes. The Companies' policy provides existing QFs more than sufficient time to evaluate the PPA and to also obtain any necessary market information to determine whether to enter into a new PPA under PURPA or to pursue other offtake opportunities for its power. Duke's policy also ensures that the avoided cost rates offered to a QF requesting to enter into a new PPA—whether a new QF or a QF that is currently selling under an existing PPA that will expire in the future—reasonably and appropriately align with the Companies' current avoided cost. As Witness Snider explained in direct testimony, once the QF contractually commits to deliver its power over a new term as specified in the PPA, the QF is then recognized in the Companies' future Integrated Resource Plans as delivering energy and capacity over the term of the contract.

IV. PUBLIC STAFF'S PROPOSED RULE REVISIONS

Q. PLEASE COMMENT ON THE PUBLIC STAFF'S PROPOSED REVISIONS TO COMMISSION RULES R8-64 AND R8-71.

A. As background, the Companies' and the Public Staff's Rate Design Stipulation implements changes to the on-peak and off-peak rate design hours, and adopts new "premium peak hours" that differ significantly from the Companies' pre-existing Option A and Option B rate designs. The Rate Design Stipulation additionally establishes a methodology for evaluating energy hours and seasons in future avoided cost proceedings. As highlighted by Public Staff Witness Thomas, implementation of this rate design methodology can result in future changes to the premium, on-, and off-peak hours and the overall rate structure included in the Companies' avoided cost rate design over time.

Commission Rule R8-64 governs applications for a Certificate of Public Convenience and Necessity ("CPCN") while Commission Rule R8-71 governs the expedited review of CPCN applications for utility-owned projects selected through the CPRE Program. Today, both rules require CPCN applicants to provide "detailed explanation[s] of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year." As explained by Witness Thomas, this requested information originates from hourly production profile data created by readily available solar PV modeling software. However, because of the Rate Design Stipulation and corresponding updated rate design, CPCN applicant's requested facility output data must be further segregated than was originally contemplated to comply with the existing language of Rules R8-64 and R8-71. Therefore, the Public Staff has proposed revisions to these rules to reduce this administrative burden on CPCN applicants by eliminating the additional processing required by the rules as a result of the Rate Design Stipulation. In addition, the Public Staff has revised the rules to allow for their review of a CPCN applicant's production profile and factors influencing the production profile's shape, including fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits.

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S SPECIFIC REVISIONS TO NCUC RULE R8-64 AND R8-71.

A. The Public Staff's proposals to amend Rule R8-64 and R8-71 are included in Exhibit G to Witness Thomas' testimony. Witness Thomas has struck the existing language of R8-64(b)(6)(iii) to now state:

> The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including fixed tilt or tracking panel arrays, inverter loading ratio,

> over-paneling, clipped energy, or inverter AC output power limits;

Similarly, the Public Staff has revised the text of Rule R8-71(k)(2)(iii)(6) to state:

> The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits;

Q. DO THE COMPANIES SUPPORT THE PUBLIC STAFF'S PROPOSED REVISIONS TO NCUC RULES R8-64 AND R8-71?

A. The Companies agree that NCUC Rule R8-64 and R8-71 are inconsistent with the rate structures reflected in the Rate Design Stipulation and corresponding updated rate design and therefore require revision. The Companies are uncertain, however, whether the impacts of the proposed revisions may affect parties that are not currently participating in this docket. Furthermore, there are numerous contested issues pending in this proceeding; therefore, the Companies believe it would be beneficial and efficient to focus on the proposed revisions to these Rules exclusively in a rulemaking proceeding before the Commission determines them to be final.

To avoid noncompliance with the Rules' requirements, the Companies propose that the NCUC authorize a limited waiver of application of Rule R8-64 and R8-71 as they are currently written, approve Public Staff Witness Thomas's revisions outlined above to the Rules on an interim basis, and direct that a separate rulemaking proceeding be initiated to review the revisions before they are permanently adopted. The limited waiver would be in effect until final revisions are approved by the Commission after the rulemaking. The Companies believe this would allow parties to comply with the NCUC Rules when submitting applications for CPCNs during the interim while interested parties and the NCUC have the opportunity to review the proposed revisions to the Rules in more detail. The Companies have discussed this proposal with the Public Staff prior to filing this testimony, and they have no objection.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MS. FENTRESS:

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

A Yes, I do.

Q Please present your summary to the Commission.

A My direct testimony supports the proposed modifications to Duke's standard Purchase Power Agreements, or PPAs, available to QFs eligible for Schedule PP and the standard Terms and Conditions for the purchase of electric power. Specifically, I address the requirements for utility approval prior to a QF owner making material alterations to a QF facility selling power under Schedule PP. I also support the Companies' proposed energy storage protocols which are applicable to standard offer QFs selling under Schedule PP.

Since the Commission reviewed avoided cost tariffs in 2016, the Companies have received inquiries from solar developers about whether altering operating QF facilities is allowed under the terms of existing PPAs. Therefore, the Companies have modified the standard term -- standard PPAs and Terms and Conditions to expressly clarify and explain how these standard PPAs and Terms and Conditions operate when a request is made to alter operating QF facilities. Accordingly, the Companies added a defined term, material alteration, to the Terms and Conditions to more clearly describe the changes to an operating QF facility selling under a preexisting PPA that would trigger the Utility's right to terminate the PPA when the QF did not seek prior authorization from the Utility before making the alteration. The term clarifies that QF owners may not modify an existing facility to increase the existing capacity, AC or DC, or to reduce the existing capacity, AC or DC, more than 5 percent. This includes the addition of energy storage. Repair or replacement of equipment, including solar panels, with like-kind equipment is not considered a material alteration and can be undertaken in the normal course of business without obtaining Duke's prior consent.

The Companies have also incorporated a definition of system operator instructions, as well as energy storage protocols for QFs contracting to sell power under Schedule PP. The system operator instructions memorialize Duke's preexisting rights and obligations to curtail QFs in a nondiscriminatory manner, when necessary, to respond to an emergency or force majeure event to maintain safe and reliable operation of the system. The energy storage protocols establish how batteries co-located with QF facilities will operate in parallel with the Duke system and will help assure that QFs effectively manage the charging and discharge of stored energy in real time.

My rebuttal testimony responds to the Public Staff's testimony on Duke's proposed modifications to the standard Terms and Conditions, specifically the energy storage protocols and the process that an existing QF seeking a new PPA would follow at the time its current PPA expires. With respect to Duke's process for an existing QF not eligible for the standard offer PPA, to enter into a new negotiated PPA before expiration of the current PPA, the QF may submit a new Notice of Commitment form 12 months prior to the end of the current PPA's term. At that point Duke will provide a fixed rate quote and a draft PPA. For negotiated PPAs the term will not exceed five years, and the avoided cost rates will be based on the Commission's currently approved methodology. Consistent with standard practice for negotiated PPAs, the QF must execute the PPA within six months of delivery by Duke. Similarly, an existing QF eligible for the standard offer PPA would automatically have the right to enter into a new 10-year PPA at the standard offer avoided cost rates applicable to new QFs as of the date the QF's current PPA is set to expire. I believe this policy provides sufficient time for the QF to evaluate the PPA and will also ensure that the avoided cost rates offered align with the Companies' current avoided costs.

With respect to energy storage protocols, Duke's objective is to establish reasonable protocols that allow our system operators to plan for and manage an integrated solar plus storage facility into system dispatch while maintaining system reliability. The Public Staff has agreed that the standard offer energy storage protocols are appropriate and they do not recommend any modifications.

In my supplemental rebuttal testimony I explain that, contrary to the assertions of NCSEA Witness Norris, the Companies' standard offer and negotiated PPAs require their consent prior to any material alteration of the QF's facility, and I further confirm the Companies' agreement with Public Staff Witness Hinton that the Companies will consider proposed modifications to QF facilities in a commercially reasonable manner. Finally, I respond to SACE Witness Glick's contention that the Companies' energy storage protocols are inappropriate. As I have explained throughout my testimony, the Companies' energy storage protocols are reasonable and necessary to ensure the safe and reliable interconnection and parallel operation of QFs proposing to integrate storage.

This concludes my testimony -- or my summary. Excuse me.

MS. FENTRESS: The witnesses are available for cross examination.

CHAIR MITCHELL: Thank you.

CROSS EXAMINATION BY MR. SMITH:

Q Good afternoon. My name is Ben Smith. I am regulatory counsel for NCSEA. I have a number of questions mostly directed at Mr. Snider; however, I think the Panel -- if any member of the Panel feels like they're more appropriate to answer it or if they have something to add, please do. And if I start talking over you, just tell me to stop.

So I'm going to start with a few background questions to help sort of clarify some positions that are -- will inform the rest of my questions. First of all, I wanted to find out from -- the solar integration charge, will Duke be applying that to the House Bill 589 programs, namely the CPRE program and the Green Source Advantage program?

A (Wheeler) Yes. It will apply the Tranche 2 if it's approved by the Commission in this proceeding.

Q Okay. And the Green Source Advantage program, they plan to apply it to those facilities in that program?

A I have not discussed that with the group that's looking into that, so I can't say definitely it will. It would for Tranche 2.

Q Okay. My next question is, can you tell me what the 20-year avoided cost rate will be, based upon Duke's methodology that was proposed in the filings in this docket?

A (Snider) We have not calculated that rate as yet, the 20-year rate, and we will be updating fuel prices, so we use the methodology, but a lot of time has, you know, transpired, so we'll be updating gas cost, et cetera.

Q Thank you. And then just generally speaking, to talk about the environment of non-House Bill 589 projects, have -- to your knowledge, have there been any new Schedule PP projects that have signed contracts in the last 12 months?

A (Johnson) Just to clarify, did you say non-PP projects?

Q Schedule PP.

A Oh, Schedule PP. I'm not aware of any right offhand.

Q And are you aware of any QFs that have signed five-year PPAs?

A So for negotiated, I am -- I am aware of several that have signed PPAs.

Q But not the standard?

A Noneligible for the standard.

Q And then one more background question. In the recently filed Duke EV pilot, Duke stated that it considered Executive Order 81 proposing their EV pilot program. I realize you all might have nothing to do with the EV pilot program, maybe you have a lot to do with it, but I'm wondering, did Duke consider Executive Order 80 when it began pushing the proposals in this docket, specifically the proposed solar integration charge, the energy storage terms and conditions, the shift in the winter capacity peak, or the expiring PPA contract issue?

A (Snider) I'm sorry. Could you restate the question?

Q Sure.

A (Wheeler) I could try to answer it. We're not involved in the EV electric vehicle proceeding.

COMMISSIONER GRAY: Please pull that microphone closer --

THE WITNESS: Oh.
COMMISSIONER GRAY: -- to you, sir. Thank you.
THE WITNESS: Thank you.
COMMISSIONER GRAY: I'm getting a little older.
A (Wheeler) This Panel has not been involved in the electric vehicle --
Q Understood.
A -- negotiations.
Q I guess I'm more asking how -- Executive Order 80 dealt with electric vehicles, amongst many other issues. How did electric or -- I'm sorry -- Executive Order 80 inform Duke when they made the proposals in this proceeding, both in the run up to Executive Order 80 and after it was issued by the Governor?
A (Snider) I would say Executive Order 80 -- and, again, I'm not a legal expert on it, but it's, you know, promoting carbon free generation in the state, but nothing in Order 80 says we should change our implementation of PURPA, nothing would supersede North Carolina House Bill 589, and so we look at this proceeding as -- as how do we appropriately implement PURPA, as outlined in House Bill 589, as it relates to past orders from this Commission, and that's what led us to all of the testimony and the schedules filed within

this proceeding. And we -- to my knowledge, nothing in that conflicts with Executive Order 80.

Q But to your knowledge, Executive Order 80 didn't inform anything that was filed in this docket?

A It didn't specify technical aspects of this docket, no, to my knowledge.

Q Thank you. Okay. I'm going to focus on you, Mr. Snider, now. I'm going to go to page 35 of your direct testimony.

A Okay.

Q And this is specifically -- and I -- and I hope I have the page number -- I have the figure number. It's Figure 5; is that correct?

A Yes.

Q Okay. Figure 5, I think it's labeled DEP Load and Solar Volatility on -- and it shows for March 10th, 2019, Gross Load Volatility without Solar and Volatility with Solar. Can you please explain sort of what these two graphs are, and do they account for the gross load of the entire DEP territory or is it just some particular area? How does that work?

A So that is simply a graph intended to say that if you just look at load alone before netting out solar -- and recognizing that the system has to follow not just hour to hour, but minute to minute, so these are five-minute deviations -- if you just look at standalone gross load, you get the top part of that figure, which is the blue line. And this really was just an illustrative example, you know, of a day to show that when you then say what does load look like after you net the input from solar coming onto the system, that you end up with a more volatile intra-hour load profile. And it was just an example in this graph so that you could depict how that volatility increases across the system when you have an intra-hour volatility.

Q And was this -- the load that's projected there, is that the entire DEP territory load?

A That is my understanding, subject to check.

Q Okay. Why was only DEP used? Why didn't you use DEC?

A We're actually making two filings in this case, one for DEC and one for DEP. They are separate legal entities. And so when we make our filings, do our analysis, you know, we do account for non-firm energy flows that go across the JDA, but other than that, we file specific rates, independent rates, for both DEC and DEP as standalone utilities, and the integration and the volatility that the system sees that they're responsible for following is subject to each utility. So each utility, for example, has to maintain its own separate operating reserves. And so we found it appropriate just to show this for the independent utility.

Q Okay. So it's just for DEP.

A Yes.

Q It also reflects just March 10th, 2019. What -- I was wondering, why did you pick March 10th, 2019 as the illustrative day?

A I just -- there -- I think we, in one of my filings -- I don't know if it was in direct or rebuttal -- I think in the back we showed several other days. Again, it's --

Q I believe it's Exhibit 1 to your direct testimony. You showed 10 days from the beginning of March 2019.

A Right. And, again, it's just to show that on balance, when you add the intermittency of solar, it's been contended in past proceedings that perhaps solar was so well correlated with load that it would reduce volatility. We demonstrated in the study -- Mr. Wintermantel will be prepared to talk more about this when -- when he takes the stand -- that on a holistic basis, that volatility increases, and so we just -- we wanted to show that pictorially what that looked like. And then when Intervenors, you know, had questions about a day, we showed some more days.

The study looks at it on an annual basis, so it was -- it was really just, again, an illustrative study to show that whether it's one day, whether it's a week, whether it's a year, intra-hour volatility, when you add a substantial amount of solar to a system, intra-hour volatility rises and it does -- does not decline. And so we were just illustrating that with -- with this single example.

Q Sure. And -- and so I guess my question, then, is would the same volatility be shown in any other day of the given year? You said holistically, so I'm wondering why it wasn't annualized in some way or -- or otherwise show something that reflects other months besides the winter.

A It's -- when you average changes, you can have -- I mean, what the study looks at is all 8,760 hours on a sub-hourly basis, so it becomes, you know, not practical to show five-minute intervals over 8,760 hours. And so, you know, this was just one example. We don't -- we make -- I think I make clear in my testimony that this is just an example and that the study looks at this much more in technical depth by looking at it on an -- on an annual basis. It wasn't -- by no means was picked as like the, hey, go find the highest volatility difference. It was -- it was a simple illustrative example.

Q Thanks. I'm going to move on to the expiring contracts issue. From NCSEA's perspective, QFs are currently providing capacity to the Utilities and -- and as they're expiring, we feel like there's no principal basis for ceasing to pay them for the capacity cost that they're continuing to help avoid. Does Duke have a position or does Duke oppose the idea where a QF and the Utility could work together and -- and sort of plan together near the end of a PPA that a QF had -- had executed?

A Yeah. I think, you know, as I explain in both my testimony and in -- in rebuttal, we believe the QF has multiple options that we're happy to work with them with. So an expiring QF, as Mr. Johnson pointed out in his summary and in his testimony, can -- can continue to serve as a must-take PURPA QF, and so within one year of its expiry can assert its PURPA rights, establish a second LEO for a new contract, enter into the new contract terms, conditions, and avoided costs that are prevailing at that point in time.

Should the Utility have ongoing solicitations for renewables that might occur in advance of that one year, the QF would be free to bid into that and -- and procure it through competitive procurement, which is the clear direction of House Bill 589, is to move more towards competitive procurement.

Should the Utility have a traditional PP -- you know, we -- DEP just issued an RFP for capacity. Should the QF desire to add storage, change its facility, and bid into a traditional RFP, you know, in advance, assuming that the need was after the expiry of its contract and that it -- it was in a position -- as I point out, if it's in a position to sell. So if it still has a land lease, if it has all the permits, if it hasn't committed to sell into a different market, if it's physically viable, financially viable, meets the terms and conditions of a -- of an RFP, it's free to -- to bid into that RFP or sell into one of, you know, Duke's renewable RFPs, participate with an industrial customer in -- in some form of Green Source. There's lots of options for -- for the QF that -- that Duke is willing to work with the QF on.

Q Thank you. So would you say -- I guess I'm going to posit -- posit this. Does Duke agree with an assertion, if this assertion was made, that it is the best interest of the ratepayers in North Carolina for clean generation assets to be used for the entirety of their useful life, assuming they're paid at a reasonable amount for energy produced and capacity provided based upon Commission rates? Is that a fair statement?

A I think it's fair to say if done at the appropriate rate. And I think, you know, the -- maybe some of the differences between the parties is, you know, when do you establish that appropriate rate, what is the appropriate rate, what's fair to be done under an administratively determined rate versus what should be done under competitive procurement? And -- and I think, you know, that might be where some of our difference is, but certainly, acquiring clean energy at the appropriate rate with the appropriate mechanism to acquire that is a good thing.

Q And this is a question having to do with REPS compliance, so I apologize if -- if this is something outside, but I -- I guess it has to do with the expiring PPAs. How does Duke project that expiring PPAs will affect its Renewable Energy Portfolio Standards compliance?

A I'm not the REPS compliance manager, but it's my expectation that right now, as I understand it, we're in a pretty significant overcompliance, we're in good shape, and that, you know, we will manage that position. And, again, it gives you multiple, as I understand it, alternatives, whether it's getting renewable energy credits from in state, certain portion can come from out of state, certain portion can come from EE. So we will continue to monitor that through our REPS compliance plan, and as contracts expire, I think we're still going to be in good shape and we'll certainly make sure that we purchase the -- the RECs needed. Again, House Bill 589, the competitively procured for the next 20 years comes with all environmental attributes. That's one of the benefits of -- of House Bill 589. So that will -- that will position the Company well through -- through the House Bill 589 implementation as well.

Q I want to move on to the Astrapé studies, and I understand Mr. Wintermantel will be testifying that -- to some of the more particulars there, but I wanted to ask you all some questions about it. My understanding, and correct me if I'm wrong, is that the Astrapé study is -- is forward looking. It's based upon the assumption that the House Bill 589 programs will be fully subscribed, including CPRE and GSA. Is that Duke's understanding as well?

A Yes. It is my understanding.

Q Some NCSEA members have made it clear that they think that some of the issues in this docket, namely, the solar integration charge, will negatively affect subscription to CPRE and potentially the GSA program, assuming the GSA program has the solar integration charge, and that, I guess, hasn't been determined yet. Tranche 1 of the CPRE was not fully subscribed, correct?

A It was very nearly fully subscribed. I think it -- you know, for all practical purposes it -- it was. DEP was more than subscribed, and DEC was very nearly fully subscribed. I think it had to do just by the size of the bids.

Q Sure. So if NCSEA's members are correct and -- and -- and the negative effect of the solar integration charge affects the subscription level of these -- of these different programs, wouldn't that undermine the Astrapé study if less than the full subscription rate is included, given that the Astrapé study makes the assumption that they would be entirely subscribed?

A Well, again, I think one of the things the study does do is it looks at various penetration levels. We did strip out anything above 589. We have more than

589 solar in the IRP. We pulled that out. We didn't let that affect the study.

The other thing the study, how we're implementing it -- this is more on our Panel, not Mr. Wintermantel's -- is part of the reason for charging an average integration charge is that it gets adjusted every two years, is that inputs that will affect the cost of integrating can be changed every two years. So if gas prices change, if the system changes and batteries drop to, you know, 20 cents on the dollar instead of 50 cents on the dollar and it makes it easier, those costs can be adjusted.

So based on our best estimates today, we think that's a reasonable estimate for the amount of solar and how to calculate an average integration charge, and that if that circumstance changes in a couple of years, we will, you know, we'll adjust that and -- and the rate will change as -- along with all the other variables.

Q I'm going to move on to some of your testimony, Mr. Snider. Page 34 of your testimony, you state that Duke has determined that solar QFs provide "intermittent, non-dispatchable power," which is markedly different from integrating firm power and, therefore, such a difference makes it appropriate to recognize the integration costs in valuing the energy and capacity provided by QFs eligible for Schedule PP.

This, to me, appears to somewhat contradict Duke's statement in their initial statement -- I think it's on page 14 of their initial statement -- that the capacity needs in winter are due in large part to solar output in summer, and that has to do with the loss of load expectation issue. So I guess I'm asking for you to make sense to me. This might be something where I just need it explained.

A Certainly.

Q How do you explain the intermittency issue on the one hand, but also having a loss of load expectation fulfilled on the other hand?

A So intermittency and -- and, really, more so than just the sub-hourly intermittency is the actual shape. When does -- you know, when is solar output -- when can it be depended on throughout the year? And as you add more solar to the grid, it changes the net load obligation that the remaining fleet has to serve, and so the more solar you add and -- you know, it's a well-established concept of the duck curve out in California that's been around for, you know, nearly a decade, people talking about it -- but in the Carolinas where we actually have both winter and summer load, unlike California that's pretty much summer, they -- they don't heat predominantly with electricity the way the Southeast does -- there hasn't been a big discussion around how not just the duck curve happens, but you can have this shift to winter.

And so as we put more and more solar on the system, that does have an effect on what is the incremental benefit. And, again, that's what -- that's what we're doing in this proceeding. Any time you come forward and -- and say what is an incremental, not the aggregate benefit, what's the incremental benefit of the next tranche of a given resource? So when you look at the incremental benefit of the next tranche of a resource, you take into account what your current stack looks like. And I can say the same thing for the decrement. What's the incremental decrement? What happens when you add or lose a little bit of a given resource? What's the impact?

And so right now, given the amount of solar we have on the system -- and also as I point out in testimony, in -- in a large part we're also seeing more severe load impacts, you know, outside of just solar. So our winter load response has changed over the last several years. We've gone through multiple polar vortex events. We've seen winter load responding in a way that, you know, a decade ago we wouldn't have imagined.

So when you pair that together, we now have a bunch of solar on the system. We have a system that is increasingly responding more severely to winter loads. You have demand-side management -- and I'm sure we'll get questions on that later. You have demand-side management programs that are more effective at mitigating summer peaks than winter. You put all that together in an LOLE study, and at DEP it's clear, you know, over several years we've been demonstrating this, that DEP, and it was recognized by -- by this Commission in the last hearing, is squarely a winter planning utility, and that means summer capacity from a -- has -- while it has energy value, it -- it's not needed to protect from loss of load risk. Loss of load risk for DEP is exclusively a -- a winter issue right now.

Q I think I understand, but I guess I'd ask you, can you just explain how Duke's model in the rate design took into account the capacity benefits of summer peak coverage provided by solar output?

A When you say "capacity benefits," it treated it as existing -- the solar that went into the study, it treated as a reduction in load. So what -- from a loss of load expectation, the solar on the grid today is must-take solar. So when you think about balancing do I have enough steel in the ground, do I have enough dispatchable generation to meet my load obligation, you take into account existing solar, and that solar has a different output, so when we say -- when I say it's a reduction in load, it varies. So just like we had multiple weather years that, say, load can change, irradiance can change, so that load is being reduced by different amounts. On a clear blue day it's being reduced by a lot. On a cold winter morning where it's cloudy it might be being reduced by a little. And you take historic irradiance data, historical load data, and when you simulate that to get a loss of load expectation, what we're seeing is that all of the loss of load expectation is in the winter.

And so existing solar on the grid is -- is simply modeled as a decrement, depending on, you know, that particular simulation to how irradiant -- how much irradiance do you have, and it would reduce load.

Q Thank you. Changing topic a little bit, South Carolina just passed the South Carolina Energy Freedom Act this summer, and that requires ancillary services to be accounted for in their avoided cost methodology. And

I wanted to know what Duke is doing, to the extent you all know, to comply with that new law, or -- or what it intends to do down in South Carolina?

A I think we'll likely be very similar to what we've done here.

Q Thank you. Mr. Snider, on page 22 of your testimony, you say that the methodology for establishing the energy and capacity rate design included considering the factors of technological changes in customer usage, such as the impact of electric vehicles or the addition --

A I'm sorry. I -- I didn't mean to interrupt. What -- what page am I on?

Q Twenty-two (22).

A Twenty-two (22) of direct testimony?

Q Direct, yes.

A Yes. Okay. Okay. I'm sorry. Go ahead.

Q No -- no problem. You say the capacity rate design included considering the factors of technological changes, customer usage, such as the impact of electrical vehicles or the addition of distributed generation or batteries. Can you explain how Duke Energy took into account EV charging when designing proposed new rate designs for energy and capacity?

A Yeah. Right now EV is -- is a portion of our load forecast. Granted, it's a small portion at this point, but, you know, there's wide debate over how that may be growing across time. But as we produce load forecasts within the IRP process, our base IRP load forecast, we take into account the impacts of -- of projected electrification of the vehic--- of the transportation sector in that load forecast.

Q Thank you. And what about distributed generation of batteries and the rate designs? I know Duke, in their IRP filings, said that they were going to put on a large amount of batteries in their territories in the Carolinas, so I guess I'm asking when -- when you do these new rate designs, how did you account for battery additions to the grid?

A We do have a small amount, actually. I mean, it's -- it's a large amount when you put it in perspective that it's nascent technology and there's not many utilities that have significant amount of lithium-ion, so we -- we do have a placeholder in the IRP, as we point out, for lithium-ion batteries that we expect can add value across the transmission distribution generation system. And those were in our, you know, as a -- as an undesignated resource, so we didn't allow those batteries to -- since they're not in place yet, they didn't supplant a capacity need, but we do put those in in our base plan to say if we were to have, you know, these batteries on the system, they would -- they would be included in both the base and the change case.

Q Thank you. Can you explain how Duke incorporated the recommended performance adjustment factor, PAF, in their avoided -- avoided capacity rate design modeling?

A Yes. Consistent with the last Commission order on that, we looked at the -- the affected forced outage rate of the fleet and said, you know, should a -- in the peaker method, how much of an additional benefit adder should we give to the capacity payment that reflects the fact that even the conventional fleet is not a hundred percent reliable and has an -- an E4 rate. And so we took that into account, looking at historic data, saw how that fleet performed, and then used that to calculate our -- our PAF.

Q And how does the PAF calculation deal with extreme weather conditions?

A Extreme weather is -- that happens, the -- the E4 that's in there is based on historic what's called GADS data or system reliability data, so any system outages that occurred historically, whether during normal weather or extreme weather, would have been -- would have been accounted for in that -- in that calculation.

Q And scheduled maintenance of the grid, is that done in the same way? I know that the PAF accounts for that.

MR. BREITSCHWERDT: Chair Mitchell, the discrete issues the Commission identified for the hearing --

COMMISSIONER GRAY: Please pull the microphone up.

MR. BREITSCHWERDT: Yes, sir. The issues the Commission identified for hearing were limited, and PAF was not one of those issues, so we've gone three questions down the path of discussing how the Company designed and developed the PAF that's included in avoided cost rates. It just seems like we're getting a little far afield from the specific focus of the hearing.

MR. SMITH: Madam Chair, it has to do with the rate design and the capacity design, in particular, that Duke's requested in this proceeding. I only have two more questions on it.

CHAIR MITCHELL: Okay. Please move along.

Q So how does Duke deal with PAF calculations when an extreme weather condition overlaps with a scheduled maintenance time?

A I don't believe -- most of our scheduled maintenance are scheduled for non-extreme periods, so we generally, for example, won't have nuclear outages in the -- in the summer or in the winter. We don't schedule routine maintenance across our -- our peak months.

Q Thanks. No more on PAF. In your direct testimony you suggest that qualified facilities are incentivized to configure -- and -- and I believe this is page 29 of your direct -- QFs are incentivized to configure their operating scheme to take advantage of these higher rate periods when energy and capacity are of the highest value to customers. How do you -- how are you -- how do you suppose they should do that?

A Again, we're filing QF rates consistent not just with PURPA and not just with 589, but this Commission, who in Sub 148 directed the Utility to come up with more granular energy rates and also to come up with a set of capacity rates that better reflected the actual capacity need of our customers and our system. We endeavored to do that. We worked diligently with Public Staff to modify our additional -- our initial offering to come up with a stipulated rate design that now has moved from three energy periods in the old Schedule B to nine energy periods across three seasons.

We have further followed the Commission's directive and reduced our capacity to when capacity has the highest and best value for customers and over a much shorter period of hours. So we are now sending the price signal consistent with the Commission's directive in -- in Sub 148, consistent with the intent to 589, consistent with PURPA, and to the extent a generic QF, be it solar, be solar and storage, be it a cogenerator, anybody that qualifies for this rate now has the price signal to design and operate their facilities in a manner that is consistent with the needs of the using and consuming public.

Q And other than adding energy storage, is there any way that you know of that a QF can change the time that it's providing power to the grid?

A That's the -- the primary way to do major shifts for capacity. I think some of the witnesses and Intervenors here talk about different configurations for a new QF entering. You may elect to do single axis tracking, fixed tilt. You may change your -- your -- your orientation of your -- your panels. You may choose different DC-to-AC ratios in your configuration of the facility. And, again, I think it's just important to point out that the rate is -- is agnostic to that. It's just saying here is where the value is. Now, you know, all -- all time periods have some value. It just delineates with more granularity, which was our intent in this design, is to come up with that more granular rate to delineate that, and then it's -- it's up to the QF and the developer across all QF technologies to -- to best optimize their facility for their own situation.

Q Thank you. In Duke's 2016 resource adequacy study, 36 years of historical weather data dating back to 1980 were used, all of which the lowest temperatures -- I'm sorry -- of which the lowest temperatures all were seen in the 1980s by three, four, and five degrees in 1982, '83, and '86 respectively and minus 5 in 1985. Don't you think relying upon something like that 36 years back emphasizes outdated and rare extreme winter peak events?

A Yeah. It also missed 2018 where we hit our all-time record peak. I think I point out in testimony, you know, that study did not have our 2018 polar vortex where, you know, we went to negative real-time, almost, operating reserves. We've seen significant cold weather events since that study, so, you know, if you use too much data or -- you know, you get a certain criticism; if you use too little, you get a certain criticism.

I think in this case the study, if anything, what we're seeing, if I were to update that study today and could snap my fingers and redo it, we may even see more cold weather response based on recent events that were not in that data set. So, no, I do not believe the use of 36 years' worth of weather data presents obsolescent data or a bias in that study.

Q All right. Changing topics a little bit, I'm going to talk about wholesale power. Does Duke consider purchasing wholesale power from a neighbor such as PJM, which is not a winter peaking entity, which might be more efficient and less expensive than the peaking winter energy rate in North Carolina?

A If we were to consider purchase power, it would actually lower -- you're right, it would lower our energy rates, but we do not. It's non-firm -- it's a non-firm path and it would be speculative to say what we might get out of PJM, depending on how much -- how much they may or may not have to sell, what their relative position is to ours, how much solar they may be integrating themselves into their own system. All of this affects PJM prices.

Certainly, when it comes to, you know, our balancing area, we have a -- a responsibility to maintain our own integration cost, so we can -- you know, we have to maintain through NERC standards our own BAAL Standards, which require that by balancing area so, no, we do not, you know, pre-assume we can rely on -- on neighbors. In fact, in recent cold weather events sometimes our neighbors have been more deficient than we've been. I mean, we've been seeing neighbors to the south during one of the polar vortex events that wanted to buy energy from us, and -- and we had to stop selling power because we needed it for our own. So you can't just assume, you know, that the neighbor is going to be there.

I will say from a -- from a loss of load risk, it's important to note that we do do a loss of load risk study that comes up with our capacity needs as an interconnected balancing area. So it's really key to understand that we don't assume when it comes to capacity and our needs, winter versus summer, that -- that we're just a standalone island. We look at, for loss of load risk calculations, the interconnecting capability, the amount of transmission, the homogeneity or -- or diversity that exists within our neighbors, recognizing that that capacity or energy purchase during extreme peaks is limited to how much transmission, but also how much excess generation that utility may have. All of that is taken into account when it comes to our capacity calculation, summer versus winter allocation.

It's only when we get to the integration services charge where we, as a balancing area operator, have a mandate to maintain our own operating reserves, that we look at it on an island. So I'm sure we'll hear more testimony on that over the week, but there isn't a difference there between the capacity study that looks at these interacted areas and the solar integration charge, which takes a look at the requirement of each balancing area to maintain its own operating reserves.

Q Thank you. I apologize for jumping around topic wise. A lot of your answers are providing me the subsequent answer, so I kind of skip ahead. Going back to the solar integration charge, do you know if the Astrapé study accounted for the two projects in CPRE Tranche 1 with storage additions in their model?

A I don't believe it did. You can ask Mr. Wintermantel that question. Again, I would -- my only point on that is it's -- we'll have to see when those two projects come on whether they use those storage devices for smoothing, which given Tranche 1, there is no economic incentive for the Tranche 1 storage devices to smooth their output, or whether they're purely using that storage device to shift energy, which I explain in my rebuttal testimony that the existence of a storage device can actually simply move the intermittency from one period to the next or actually exacerbate intermittency.

So when you say, you know, did they include it, the question is how would they have included it? Would they include it just as an energy shift so that all the intermittency stays or are they going to use those batteries to smooth? And, again, given the fact that Tranche 1 had no solar integration charge for them to financially benefit from smoothing, my strong belief is that they're going to use that battery storage to simply shift energy from one low cost period to another high cost period and -- and likely do nothing to eliminate or smooth the intermittency associated with those projects. But, again, you can -- you can follow up -- with Witness Wintermantel on that.

Q Thank you. One of the provisions in the Stipulation, I believe, allows for QFs with storage added to be exempted by Duke, with Duke oversight and -- and the underlying contractual requirements that Duke is asking for, to be exempted from the solar integration charge; is that correct?

A Yes. As part of the Stipulation, if you want, should the QF implement a storage device and wish to use it for smoothing, we've agreed with Public Staff that it would be appropriate to waive the integration charge.

Q So based upon that assumption and other assumptions made, I guess based upon that assumption, is it reasonable for the Commission to conclude that a solar facility with energy storage could be more valuable to Duke's system than a solar only facility?

A When you say "more valuable," if the avoided cost rates, as calculated in this, are correct, it's equally valuable. You're just changing the value. You're saying I'm going to get higher cost energy at full avoided cost. So as a customer, if you -- if you really believe the rates, however they were determined by this Commission, were perfect, whether you add storage or not, you've given an indifference rate. The customer is indifferent to adding storage or not adding storage because it's at the full avoided cost in this proceeding.

So there is no -- unless it's done through competitive procurement, where the customer is actually receiving the benefit of something being provided at below the Utility's full avoided cost, anything provided at the full avoided cost with storage, without storage, solar, hydro, cogenerator, at full avoided cost leaves the customer indifferent. That's the fundamental purpose of an avoided cost rate, is an indifference cost.

Q So when you're -- when you're talking about value, you're -- you're looking at it strictly from the amount that a customer pays for energy and -- and things like that. You're not talking about anything -- carbon emissions or anything like that?

A No. I mean, value, as defined in PURPA, is -- and in House Bill 589, is what -- utility costs that are being incurred from the purchasing of QF, how are those related to the rates that the utility customer is paying for them? And the -- the fundamental indifference principle or but-for principle says the customer should be left indifferent between buying QF energy and buying energy otherwise produced by the Utility. And so to the extent you're -- you're doing one or the other at an indifference price, the customer does not get extra value. That, I believe, is the fundamental -- one of the fundamental drivers to move to House Bill 589, was to see some value or some consideration to the customer, where the customer actually would get a benefit and share in the benefits of renewable power.

Q Thank you. Moving on, I guess I'm going to move to your responsive testimony. And I -- and I apologize, I don't have the page in front of me, so subject to check, Mr. -- you said in your responsive testimony Duke is not opposed to entering into a new PPA or negotiating a modified PPA at Duke's current avoided cost rates and terms and conditions if an existing QF proposes to add energy stor--- battery storage. Does that sound consistent with what you said in your responsive testimony? Or it might have --

A Yes.

Q I believe --

A Yes.

Q -- it's your supplemental.

A Supplemental.

Q Yes.

A In the supplemental. Four rounds of testimony, trying to keep them straight.

Q I know. It's --

A Yeah. In supplemental our position is I think that's -- I'll restate it just to make sure we're on the same page -- that, yes, if you look to materially alter an existing legal contract, that the most appropriate thing for customers would be for that contract to be reopened and reentered into the entire output of that facility at the now prevailing avoided cost rates.

Q Thanks. And it's your view -- or is it Duke's view that the current or more updated avoided cost rate is more accurate than prior avoided cost rates, at least today?

A Yeah. I believe in our reply comments we point out that today customers are facing, from existing executed PPAs, over the next 10 to 15 years four and a half billion dollars in obligations to the QF community, with a projected value of about 2.3 billion, which is going to result in about a $2.2 billion overpayment over the next 10 to 15 years. So, yes, we think it's important to adopt at the most prudent and reasonable rates which are those that are filed in this case.

Q Thank you. So in other words, it's your view that the most current avoided cost rates provide the more accurate price signals; would that be fair?

A Yes, certainly.

Q Yeah. So is it reasonable to conclude that a generator capable -- capable of dispatching more power during the updated on-peak periods of the current avoided cost rate schedule is preferable as compared to a generator which cannot produce in those then current on-peak periods?

A No. Again, the on peak, the off peak, the -- the premium peak, the capacity, those are all indifference prices. So when you say "preferable," is it preferable for me to go sign up an off-peak QF versus an on-peak QF? Either. They both provide the same value. It's their indifference value, right? When I -- I'm defining the term value as what additional benefit does the customer get from subscribing to off peak versus on peak? And the customer, while it avoids a larger payment by a QF, is still getting an indifference price, so the customer is no better off if it signs up one type of QF over another.

That's the whole purpose of going to more granular rates. The customer has -- the benefit received over those nine energy price periods and three capacity periods leaves that customer indifference. It -- it doesn't say that I get more benefit in one period versus another. It just says it's brought a higher price, so, yes, there's a higher price because there's a higher -- if what -- maybe we're talking past each other. If you're saying there's a higher indifference price to the customer, yes, there is, that there is -- is a higher on-peak winter morning price today than off peak in the shoulder, then yes. The customer is getting that higher indifference value, but he's indifferent to that and the Utilities otherwise providing it. So I think it's just maybe a definitional thing, that we're -- we're talking past each other.

Q Sure. So would you agree with the notion that a solar generation with storage is more capable of providing dispatchable output?

A Yeah. Again, I pause at the term dispatchable, because this is still -- in the context of this proceeding, this is not a dispatchable. It's simply a price signal. The solar can, at their sole discretion, can elect to, and I would suspect they would, shift energy from off peak to the capacity premium hours, but it's -- it's still a must-take obligation on behalf of the Utilities, so the Utilities are not dispatching that asset. It's -- the QF is moving the must-take energy at the QF's sole discretion, subject to the storage protocols. They're going to move that energy as they see fit to optimize their revenues, which is a good thing, because that is, again, aligned with the Utility's avoided cost. So I'm not saying it's a bad thing. It's just not dispatchable.

Q Thank you. Moving on to PPA lengths for added storage, this is from your rebuttal testimony. I'm characterizing that -- that you said the PPA tenor should be available to added storage, and I read what your testimony is to say is that you're opposed to providing more than a five-year PPA tenor to storage added to a QF. Is that a fair assessment?

A Yeah. If it was going to be done at the full avoided cost rate, right, so the -- the one that's -- that's the 10 year at full avoided cost, not at a competitively procured price. So we now are going to say let's take a new storage device. Let's say an 80 MW solar facility adds a 20 MW storage device, and now that 20 MW storage device wants a 10-year PPA. Let's say there's 10 years left on that 80 MW contract. They want it at full -- at today's full avoided cost price. Well, that's 20 MW of additional generation in that time period at full avoided cost.

To me, the clear intent of 589 was to say if you -- the exchange for a long-term contract was that you -- the customer would receive three considerations. It would get it competitively bid at below avoided cost, not at full avoided cost for 10 years, it would get the full environmental attributes of that output, and then it would get utility control, more utility control of that than it would under full avoided cost.

So, yes, it is my position that if -- if within that construct the output of that 20 MW battery in my example wanted a full complete avoided cost and all the PURPA benefits, that that would be inconsistent with the clear intent of House Bill 589.

Q Do you -- would you agree that a key reason to install solar storage on a solar generator for a solar developer is to time shift generation from one time period the other -- to another, rather than to generate additional electricity?

A I think, as I've stated in my testimony, it's probably both. You're going to do two things. You're going to time shift, and to the extent you've over paneled, there will be seasons or days where you're going to take what's called clipped energy. That's extra solar energy that's not flowing to the grid during the middle of the day because you're inverter limited. You're going to move that energy into the battery, and then you're going to put that energy back to the grid when it's, you know, the -- the highest price for that following period, likely the following day. So there's examples where you can increase output. There's other days where you don't have clipped energy where you're just shifting.

Q So would you agree that based upon the proposed rate design in this proceeding from Duke, that a financially savvy QF with storage on it, that they would find a way to have storage -- stored energy available during those winter peaking mornings, if possible?

A Yeah, to the extent -- again, and I point out it -- it depends on the ratio of batteries to solar. So if you put on a small battery with a large solar, you're likely going to be able to charge it and then discharge that across that peak. If that battery size gets big, then the probability that that battery has energy in it goes down. So, you know, again, on a rough example, if I had a 80 MW solar and an 80 MW battery, even though solar is out many hours in the day, you still might not be able, if it was a four-hour lithium-ion battery, on a winter day with any amount of cloud cover, you wouldn't be able to get the full output.

But, yes, I would think, you know, they're going to -- financially savvy, having worked on that side of the business before, they're going to size it to make sure they can, and they're going to make it small enough so that they get, you know, the most value out of that, and they're going to shift it to -- to those winter mornings.

Q Thank you. And do you think it would be fair to say it would benefit ratepayers and potentially cure some of the winter morning peak issues if solar plus storage facilities were online and dispatched stored energy during those times?

A Yeah. I think that's where we have just a fundamental disagreement, is it doesn't benefit ratepayers. If what you're saying is benefiting ratepayers means it leaves the ratepayers with financial benefit, it does not. Okay. Shifting energy to the peak at full avoided cost rates leaves the ratepayer indifferent. It would benefit ratepayers if it was competitively procured at below avoided cost rates or if the QF entered into a negotiation to provide that battery at output that was below avoided cost rates, and that's where I think I concluded my summary with the Commission should at least think about, should it desire to look at this potential, some consideration or benefit to the consumer for extending a 10-year contract life outside of House Bill 589, which is -- is saying five years is really appropriate, and if the -- if the QF wants a longer term, the consumer should see some benefits.

Q Thank you. Does Duke ever make energy purchases on the wholesale market when they have extreme events or anything else that requires them to buy energy elsewhere?

A Yeah. The Company certainly makes wholesale transactions.

Q And are those wholesale prices ever, due to market issues, higher than the -- than current avoided cost rate?

A I'm sorry. I don't know what you're -- I -- can you rephrase your question? I'm trying to understand where you're coming from.

Q When they buy energy in the wholesale market, is the energy they pay for in the wholesale market due to market forces ever at a rate higher than what the then avoided cost rate would be?

A Not to my knowledge. And, you know, in general, you know, you think about it, if the Companies' marginal cost to generation is lower than its neighbors by enough to cover the transaction cost, including losses, wheeling, et cetera, it will sell. If the marginal cost from the neighbor is cheaper than the real-time avoided cost, the -- the Company will buy. That's my general understanding of how our -- our power desk engages to keep fuel cost low for customers.

MR. SMITH: I just have one more question for

Mr. Snider, and then just a couple of questions for you -- or for Mr. Wheeler.

Q On page 26 of your supplemental rebuttal testimony, Mr. Snider, you state "Equipment installed on QF side of the point of interconnection is within the QF's total physical and electrical control, enabling the QF the opportunity to materially change the operation of such equipment without the Companies' knowledge or control." I guess my question on this is what's your concern with a QF having physical or electrical control of this meter?

A I'm going to -- that was -- actually, Mr. Wheeler respond to that.

Q Oh, I apologize.

A (Wheeler) Our concern is we normally install our equipment on our facilities. When we go inside a customer's facility and install a meter, for instance, we have no control over how that meter is managed in the future. It's all the customer's equipment, all the customer's wires. He could rewire it. We would have no knowledge of it. He could put it in an unprotected area or he could build a wall around it. We'd have no control to even know that -- know that was happening. So when you install equipment -- our equipment inside a customer's facility, it's a total lack of control from our perspective. That's the concern.

Q Thank you. So when you buy -- when Duke buys energy in the wholesale market, do they have similar concerns about control outside of their -- issues outside of their control?

A That's -- we're talking about a physical asset with a meter, not a legally entertained contract between two parties to exchange energy at -- at an agreed upon price and quantity, so I don't see where -- how those two relate to each other.

Q I guess I'm just talking about it if you look at them as a generation asset in some way, if you're buying energy from one, and then otherwise buying generation from somebody else.

A (Snider) Yeah. And -- and, again, I'm not the expert who -- it's been a while since I've worked on the -- on the trading floor, but the -- the metering of that wholesale transaction, first, it's done through a -- sort of a tag and a schedule and an exchange on the transmission system. We have the -- the capability to measure that transaction without -- let's say I don't have to go into PJM's control room, get behind three doors, and then, you know, ask for permission to see what power was sold from PJM. I have an exchange. I can measure power flows over that exchange.

So that's very different than -- than what Mr. Wheeler was talking about, where we'd have to egress someone else's property with their electrical systems and configurations and ensure we did it in a safe and reliable manner. That's -- that's a whole different issue. So, no, I -- those are sort of apples and oranges from our perspective.

MR. SMITH: Thank you. No further questions at this time from NCSEA.

CHAIR MITCHELL: We're at a good stopping point now, so let's take a short -- go off the record, take a short recess, come back on at 3:45.

(Recess taken from 3:26 p.m. to 3:46 p.m.)

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

MS. BOWEN: Thank you, Madam Chair.

CROSS EXAMINATION BY MS. BOWEN:

Q Okay. Mr. Snider, hi, again. I'm Lauren Bowen with the Southern Environmental Law Center. I believe we've spoken before in these proceedings. Here today on behalf of Southern Alliance for Clean Energy. I'm going to start with some questions for you, and then I may have a couple for Mr. Johnson, then my colleague, Maia Hutt, may have some questions for Mr. Wheeler.

Okay. Mr. Snider, I know you are familiar with PURPA and its requirements. Would you agree with me that Section 210 of PURPA was intended to encourage cogeneration and small power production?

A (Snider) Yes, so long as it was done at the determined avoided cost rate and did not disadvantage the retail customers who are paying for it.

Q And -- and understanding that the caveat is there that -- that you've explained in your testimony, but -- and just to be clear, PURPA specifically provides FERC shall prescribe rules to, and I quote, "encourage cogeneration and small power production and to encourage geothermal small power production facilities not more than 80 MW of capacity." You agree with that?

A I would.

Q Okay. And the US Supreme Court has also acknowledged this in its case law, which you're probably also familiar with, Section 210 of PURPA was designed -- I'm quoting again -- "Section 210 of PURPA was designed to encourage the development of cogeneration and small power production facilities." Would you agree with that?

A Yes.

Q Okay. And would you also agree with me, subject to check, if needed, but there is Supreme Court case law saying that Congress believed that the increased use of these resources -- of these sources of energy -- excuse me -- would reduce the demand for traditional fossil fuels?

A Subject to check.

Q Thanks. And small power production facilities or -- or we call them qualifying facilities or QFs in this context, those include renewable energy resources like wind, solar is what gets the most airtime in these proceedings, hydroelectric power, those kinds of resources?

A Yes.

Q Thanks. And would you also agree, I know that you would, that PURPA and FERC's implementing regulations, including FERC Order 69, took ratepayers into account?

A Yes. That was an important part.

Q And would you acknowledge or -- or agree with me that FERC Order 69, for example, acknowledged some benefits to ratepayers in the form of, and I'll quote again, "Ratepayers in the nation as a whole" -- excuse me -- "that the avoided cost construct ultimately benefits ratepayers and the nation as a whole from the decreased reliance on scarce fossil fuels, such as oil and gas, and the more efficient use of energy"? Subject to check, if you need to.

A Yeah. I --

Q That sounds about right?

A Subject to check, that sounds like you quoted that correctly, yes.

Q Okay. Great. Thanks. Mr. Snider, you've been involved in many of the North Carolina avoided cost proceedings over the years?

A Yes, I have, Ms. Bowen.

Q Yeah. And you've testified going back, I believe, to at least the Sub 136 proceeding, possibly before that?

A That is correct.

Q Okay. In that testimony over the years you have made recommendations to this Commission regarding how it should implement PURPA in North Carolina; is that right?

A Yes, I have.

Q Okay. Those have included, for example, recommendations like reducing a performance adjustment factor for QF facilities; is that accurate?

A I wouldn't say reducing. I would say instituting an appropriate PAF that reflected the true but-for principle under 210.

Q But reducing, for example, from 1.2, which it was at one point in time -- at one point in time, to 1.05 as the multiplier, you've made that --

A Yeah.

Q -- recommendation?

A Yes.

Q You've also recommended adjusting seasonal allocations for capacity evaluation for QFs in prior proceedings --

A Yeah.

Q -- but also this proceeding?

A Right. Just as we update PURPA, all the market and changing circumstances are required to be updated as part of a normal QF PURPA filing.

Q And in this particular proceeding, for example, we're suggesting that the weighting shifts so that DEP will pay all of its annual capacity value or account for all of its annual capacity value in the winter. DEC's new rates account for 90 percent of the capacity value for QFs in the winter, 10 percent in the summer. Do I have that right?

A You do have that right.
Q Okay. In avoided cost proceedings, the past few avoided cost proceedings, Duke has also made recommendations -- I believe you've testified to some of these as well -- regarding, for example, natural gas projections specifically around, for example, using 10 years of forward natural gas prices?
A Yes.
Q Okay. Would you agree with me that your recommendations in these proceedings includes -- including some of those that we just discussed, have all had the result of lowering the avoided cost rates or -- and the payments offered to QFs?
A No, they have not.
Q Okay. Can you give me some examples where they have not?
A Certainly. The new rate design, as outlined by this Commission in Sub 148, called for a more granular rate design.
Q Uh-huh.
A So despite having falling gas prices, despite a PAF reduction, we've also consolidated our capacity payments to those critical hours where capacity truly has value for customers. So if you were to actually look at

the nominal dollar per MWh paid right now for winter capacity and looked at it, that it's only being spread over a three-hour period, that sends a tremendous upward price signal that values not only the increased energy cost in those hours by going more granular, but also consolidates the capacity payment from what was a broad Schedule B that had, you know, a long on-peak period to a much narrower.

So you think about a four-hour lithium-ion battery right now, under the new rate design it has an ability to attract a much bigger portion of the CT avoided cost than had we not made this new rate design. So the -- the new rate design actually increases the avoided cost payment made to certain technologies. And as I was explaining in -- in my testimony before the break, we're agnostic to what the QF is. Is it solar? Is it solar paired with a battery? Is it a cogenerator? It's -- what's at hand here is what is the true avoided cost value by these granular time buckets. And for some of our time buckets we actually have a much higher price signal that's going to incent, you know, certain QF technologies appropriately in a manner that the old rate design did not.

Q Well, let's talk about solar QFs for a minute, because as we all know, that's the -- the predominant QF type that we have in North Carolina. You would agree with that?

A Yes, it is.

Q And the new rate design that you proposed and that's been filed in the Stipulation in this proceeding, as we -- as we talked about, shifting most of that capacity value to the wintertime, so what is that going to do for -- what do you anticipate that will do for payments for solar QFs in particular?

A So to a solar QF that does not wish to add energy storage, relative to a rate design that paid for summer, it will reduce it. For a solar QF that wishes to add energy storage, it will increase the capacity payment.

Q Okay. And then the -- one of the other examples we -- we talked through is natural gas projections, and that has been an issue in -- in the past several avoided cost proceedings. The proposals you've made on that topic, those have generally reduced the avoided cost rates, would you agree with that, for all -- for all QFs, not just solar?

A Again, I think it's relative to what. I mean, it reduced it relative to using something above market, so as recent as last week we just bought another 10 years' worth of natural gas. It's at a price slightly lower. Point that out in testimony that what were used to define these rates. So the market as it exists today is cheaper than the market that existed back in November, and so we're not proposing that we come in and refile these rates at a lower rate. We're simply saying that we have a long history now of actually purchasing natural gas out 10 years, demonstrating a liquid market, showing that that's the indifference price for the consumer, and that that is today lower than it was back in November. So it's not -- we're not lowering it in asking to lower it now, but is it lower than if I were to use a nonmarket based price that says, okay, the Utility can buy gas here, but we're going to pay for power up here. Yes. It's -- it's lower than a -- than a projection that's above market.

Q And the performance adjustment factor, that -- my understanding is, you know, that's just a multiplier, right? So if you're going from, for example, 2.0 for -- a factor of 2.0 for certain facilities, maybe not all of the facilities, but certain types of QFs, and then you're reducing that to 1.2 or 1.05, that is -- that is lowering -- that is ultimately lowering the avoided capacity rates that they'll be receiving?

A Relative to using a bigger number, yes. Relative to any other state in the country, I've, over the years, been unable to find anybody else that actually applies a PAF, so the fact that we actually apply one makes our rates in North Carolina generous by comparison to any other state that implements PURPA, that I'm aware of. I've yet to find anyone that applies a -- a multiplier. We think the one that -- that we apply right now is just and reasonable, and that is also consistent with this Commission's finding in Sub 148.

Q Mr. Snider, you've made other recommendations in the avoided cost proceedings, including shortening the standard offer contract term lengths for QFs and reducing size of QF facilities that qualify for standard offer contracts. Would you agree with that? I know that was a two-part question. I can split it up if you need me to.

A Subject to check, I think some of the recommendations I've made are now consistent with the North Carolina House Bill 589 that also codified some of those recommendations.

Q And to be clear, some of those recommendations you made before House -- you were -- you were anticipating it, but before House Bill 589 was enacted;

is that right?

A Yes.

Q Okay. And then would you agree with me that those recommendations all made terms and rates less favorable for QF power development than they were previously in North Carolina?

A Less favorable if you're viewing it from the equity holder of the QF. I would argue more favorable if you're looking at it from the perspective of the consumer who has to pay for those QF purchases.

Q Maybe let's think about it this way. So for many years North Carolina -- you would agree with me North Carolina is second in the nation for solar installed capacity? I think we still hold that ranking. Is that your understanding?

A Second in solar, number one in PURPA solar.

Q Yeah. And in the last biennial avoided cost docket, and really before that, you made the argument that we were having this surge in QF power and we needed to ratchet it back. That was the rationale for making some of the proposals that you did.

A No. I --

Q Would you agree with that?

A No, I wouldn't.

Q You --

A Not at all.

Q You -- you don't recall having your -- in your testimony references to surging QF power?

A I think the -- the reference is that -- there's nothing wrong with surging QF power. Having QF power is a very good thing. It's when you're doing it at a cost that's substantially above the value that's being created for the consumer that it led to all of those recommendations. The fact that we sit here with a $2 billion overpayment over a very short period of time, this isn't a 40-year asset or a 60-year asset that we're going to recover this $2 billion overpayment. It's over the next 10 to 15 years. That has the effect of being like an $8 billion overpayment on a long-dated asset.

So my recommendations had nothing to do with surging solar or surging QF. It had everything to do with ensuring that we were paying the true but-for indifference price so that consumers were not left paying above what value is being created in the energy and capacity that they're buying for.

Q And -- and when we're talking about QF power, to the extent that QF power displaces utility-owned generation, does that have implications for Duke Energy and your fleet?

A Yeah. Implementing as how we operate the fleet, the type of resources we build, when we build them, all of that is -- is impacted by QF -- the type and amount of QFs that come on.

Q And -- and for utility-owned generation, you earn a rate of return on those investments; is that right?

A Yeah.

Q And -- and have an obligation to your shareholders to do so, Duke Energy does?

A Obligation to shareholder, obligation to customers. I mean, we earn a regulated rate of return that this Commission oversees, and those assets are not allowed to be put into rate base without an extremely extensive CPCN, Certificate of Public Convenience and Necessity, process that is not required of the QF power. So, yeah, there are fundamental differences in how we put assets into rate base versus how a QF earns a return.

Q And Mr. Snider, are you aware that Congress, in enacting PURPA, acknowledged that electric utilities had historically been reluctant to purchase power from and sell power to nontraditional facilities like small power purchasers?

MR. BREITSCHWERDT: Madam Chair -- Chair Mitchell, before --

COMMISSIONER GRAY: Speak up, please.

MR. BREITSCHWERDT: Yes, sir. Before Mr. Snider answers Congress' original intent in enacting PURPA, I'd just note that the focus of the proceeding, as noticed, was on discrete technical and policy issues. And he's gone through pretty foundational principles of PURPA and policy arguments that we've all been through before, but it seems like we're rehashing a lot of issues that are general PURPA implementation and are not specific to the discrete technical issues -- the new issues the Commission has noticed for hearing in this proceeding.

MS. BOWEN: Chair Mitchell, this actually was my last question in this line -- in this line of -- of questions, and -- and I do think it gets to the heart of what the Commission is doing in this proceeding, which is implementing the federal law of PURPA and whether we're encouraging or discouraging QF development.

CHAIR MITCHELL: Ask your last question, please.

MS. BOWEN: Thank you.

Q So subject to check, if you need to, but the US

Supreme Court in FERC versus Mississippi in 1982, and I -- again, I quote, reluctant -- "Congress recognized that Utilities were historically reluctant to purchase power from and sell power to nontraditional facilities like small power purchasers." Subject to check, would you -- would you agree that's an accurate -- did I --

A I think your reference was to an 1982 --

Q Uh-huh.

A -- order?

Q Yes.

A That -- yes. I would say that subject to check, that might be what either Congress intended in '78 or the Supreme Court intended in '82. I don't necessarily agree that any of those circumstances are necessarily applying in this case. I mean, we have not been reluctant. As you point out, we're the number one purchaser in the country of PURPA. We have at DEP over 1,000 MW, actually approaching 2,000 MW of -- of wholesale purchases that are not from QFs, that are from wholesale -- small wholesale power providers. So some of those intents that were expressed -- again, and this was in an era of the oil embargo, energy crisis, energy independence, all of those facts and circumstances were true at the time, and I will agree with Ms. Bowen that

that was the intent of Congress and those were the -- the statements of the Supreme Court in '82, but I would just respectfully ask that the Commission sort of consider the unique evolution that's occurred here in North Carolina with respect to those very circumstances.

You know, I don't think energy independence is -- is any longer at the foundation of PURPA. I don't think that the Company has a record of being unwilling to purchase small power from either QFs or non-QFs. So to -- to imply that we are -- somehow because rates are lower due to market circumstances, due to needs for capacity, due to shifting needs for capacity, is somehow an organized attempt on the Utility to not purchase QF power I think is an unfair characterization. I think we've demonstrated quite emphatically that we are anything but reticent to purchase. We're just trying to ensure through these proceedings that it is done at the appropriate price for consumers.

Q So just to focus in on North Carolina now, as you've requested, the testimony from the Panel earlier -- and I apologize, it was -- it might have been Mr. Johnson; it might have been you -- said that we have -- we have had no QFs sign up for the standard offer rate approved in the Sub 148 docket in the past 12 months.

Did I hear that right earlier?

A I'm going to say subject to check, because I -- it was my understanding, and we'll -- we'll have to get back on this, that -- I don't know about in the last 12 months, but we have had some QFs sign up. I don't know at what time they signed up for the 148 rate. Again, a lot of that has been a shift, as intended, to competitive procurement, but that -- I don't believe the answer is zero unless it's a timing issue because I -- I do believe -- and, again, this is subject to check -- that we have signed up some QFs under the Sub 148 rate offering. I'm -- I'm just not sure of the timing of when they signed up.

Q Okay. So the testimony as it is right now was some QFs have signed up, but we also heard zero, but subject to check, we can follow up?

A (Nods affirmatively.)

Q Okay. Thank you.

MR. BREITSCHWERDT: (Nods affirmatively.)

MS. BOWEN: Thanks.

Q And you testified a little bit to this earlier, but -- but, again, the context in North Carolina has changed. We now have House Bill 589. We have a competitive procurement process. We have community solar

programs being developed. Do you agree with that?
A Yes.
Q Yes?
A Yes, we do.
Q And Green Source Advantage program, you've mentioned that earlier today. And the avoided cost rates determined in this proceeding now have implications not just for QFs under the PURPA paradigm, but also for these other programs. Would you agree with that?
A The -- the rate design does, yes. The design, because it's more accurate, reflects. Now, we will have 20-year avoided cost rates under this design or whatever design this Commission approves, so they won't be the same rates, but the design and the intent to more accurately price, granularly price and accurately price energy and capacity time periods, that will carry over to the avoided cost cap and in future tranches and future programs under 589.
Q And that's for the competitive bidding -- the CPRE program is what you're referring to?
A Correct.
Q And then for Green Source Advantage program, my understanding is avoided cost rates will also have an impact in that program; is that your understanding?

A I'm not the expert on that program, but it is my understanding generally, yes.

Q Okay. And then similarly for the community solar program, the avoided cost rates, I believe those are the -- the most currently approved will -- avoided cost rates will be the ones used in the current iteration of the community solar program. That may change in the future, but for now there is that -- that link; is that your understanding?

A Subject to check, yes, that's my understanding. Again, not the program manager for that program, but...

Q Okay. Thank you. And so you've talked some about the rate design proposal. Let's talk for a minute about the grid integration charge. Will that have -- I think you all have testified to this actually in response to Mr. Smith's questions, but will that have implications for some of these other programs, the grid integration charge specifically?

A Yes.

Q And turning back to -- well, yeah, we'll just leave it at that for now. Well, let me -- let me ask a follow up. Would that -- do you think -- is it going to have implications for all three of those programs that we mentioned? So CPRE, I believe the answer is yes; is that right?

A Yes, as of right now. I think, you know, there is still a lot of discussion going on as CPRE Tranche 2 is yet to be launched and, you know, we have ongoing discussions on that, but, yes, it's a cost causation issue, as Mr. Wheeler testified to, and all incremental solar on the grid is contributing to the cost, so in some way, shape, or form it would have an impact.

Q Okay. And then for Green Source Advantage program, I know you're not the expert on that, but you think it may have implications for that program as well, specifically the grid integration charge?

A Again, subject to check, and not as the program manager, but yes. If it was -- if the implementation of that program resulted in additional solar on the grid, that additional solar would have a cost causation with incremental sub-hourly intermittency and it would have an impact on that.

Q And potentially there's a -- there may be a relationship with the community solar program as well?

A Potentially, yes.

Q Okay. Let's go back to the -- this docket and -- and the QF -- QF power and the standard offer available to QFs and for -- and negotiated rates for the larger projects. Do you think that the grid service integration charge will encourage or discourage further QF development in North Carolina?

A I think it will send the appropriate price signal and, you know, if -- I think we've taken a lot of steps to make sure we're not discouraging. We originally were looking at this. Most states have implemented this as an incremental charge, which would have been much higher. We think the average is more appropriate. It blends in over time and charges all solar QFs equally, rather than taking the most incremental tranche and charging them a very high integration charge, so that was a measure to -- to have it be less impactful.

In formulating our Stipulation with Public Staff, we agreed with Public Staff to put a cap on the integration charge. So even though it's a 10-year contract and there is unknown integration cost into the future, to assist the QF in obtaining financing and being able to have some certainty, we've capped the integration charge at -- at reasonable caps that allows the QF to -- to view their risk with an exposure that's limited. Again, that -- if the actual cost were to exceed that, it would be a cost borne by customers that the QFs would get the benefit of.

So I think we've taken ample steps to institute the solar integration service charge in a very incrementally balanced manner that tries to balance the effect to the QF community, with the undisputed fact that it's causing customer cost to be incurred, or reducing value might be another way to say it, to a customer from having to follow this intermittency. So I don't know that it's discouraging it. I think it's sending the appropriate price signal, and it's being done in a very balanced manner that was very thoughtful to the QF community in how we rolled this out.

We're making no effort to retrospectively apply this to existing -- the 3,000 MW of existing solar on the grid. We're, you know, looking at -- at ways to offer up the QF an ability to mitigate its own. We agree with Public Staff on that, that if the -- the QF can demonstrate that it employs a technology to eliminate its intermittency or substantially reduce it, that we would consider, you know, at that point waiving the integration charge.

So I do think, you know, again, this is not being done to discourage. It's being done to appropriately place cost causation together here, and -- and when you add a significant amount of intermittency onto the grid, the -- the Utility stack has to respond to that and there's a cost to that. And we've -- we've stepped in with a very balanced approach that has a very small cost adder that -- that I think balances that -- that interest of the QF and the interest of the customer very well.

Q Can I follow up on -- on something you just talked about? So the proposal in the Stipulation filed by Duke Energy and Public Staff relating to the integration charge includes, as you mentioned, a provision whereby a QF could try to avoid the charge by demonstrating that they have incorporated storage or some other management tools. Forgive me. I don't have the exact language in front of me. But basically if they've -- if they've integrated something like battery storage to avoid some of the integration cost, then they would be able to potentially waive that charge. Do I have that right? I know that was a long question.

A Yes.

Q Okay. And my understanding is that the provision around that in the Stipulation is that it would have to be done to Duke Energy's reasonable satisfaction.

A Right. What we're trying to get at there -- and, again, in the context of this proceeding it was hard to come up with the complete contractual language on that in a very short amount of time without getting input from all parties -- and we're committed to doing that in our storage protocol; we continue to commit to do that -- is that you have -- just the mere existence of a battery does not guarantee that you're going to have less intermittency. As a matter of fact, unless it's operated with that intent, you might have the same or more intermittency. So all we're trying to get to in that is that you have to demonstrate that you're using the battery in a manner to reduce intermittency and not just block shift power from one price period to the other and leave the net put of the -- net output of the facility still very intermittent.

So that was the intent of that statement, was, you know, and where we intend to work with stakeholders on this is, you know, we're not trying to be arduous here; it's just demonstrate that the battery is being used for smoothing. And if -- if that is -- is able to be demonstrated, then, yes, it wouldn't be appropriate to still charge them an integration service charge.

Q What are your plans to work with stakeholders on that?

A I know we have ongoing -- and I'll turn to my colleagues here if they want to add to this, but, you know, we have a pretty extensive process going on through CPRE with -- with respect to our battery storage protocol. We were at a technical conference a few weeks ago that I attended. We're, you know, continuing to get feedback throughout that process. And I think, you know, we'll -- we'll continue that.

Q Okay. And the charge -- but the charges and the caps, those are set by the Stipulation, from Duke Energy's perspective?

A Yeah. The -- the actual charge itself, again, the average charge and only applying to net new, along with a cap, have been -- have been set for the next two years and then will be updated.

Q And on that -- on that update or that refresh, help me -- help me understand something. So in the last avoided cost proceeding, the Commission considered whether to reset energy rates every two years, and they declined to adopt that recommendation and said that it was not giving, you know, the long-term certainty needed to finance projects, basically. So can you help me understand why this two-year reset on the -- the two-year reset on the integration charge is different from that?

A Certainly. First of all, the integration charge is very different than the energy charge. I mean, we've -- we've had numerous proceedings. As you've pointed out, you and I have been at these tables longer than I care to recount. And so the energy and all the issues affecting energy have been widely debated, everything from gas prices to PAFs to everything that we just spoke about. The integration service charge was originally brought up in Sub 140, and I believe the Commission thought it was a little premature at the time. There was a pretty detailed PNNL study that identified the cost.

And then, you know, as we've added more solar to the system, these costs have become more known and measurable. We have an additional study that was done and presented in this case. But we elected to implement that charge, again, as an average integration charge to be updated. We originally thought about could we come in? Would it be better to come in as an incremental, much higher charge, and fix it for 10 years of this contract? The charge would have been significantly higher and it would have been fixed.

This now is a significantly lower charge for the QF, to the benefit of the QF, that will be adjusted over time such that the QF is not subject to the higher charge right out of the gate, that there is time for technologies to evolve, that there is time for the Commission to further study this and not lock us into 3,000 MW worth of, you know, a single charge like we did with the energy rates. It -- it can relook at this every couple of years and say have the facts and circumstances changed as the Company and the parties present their evidence to either lower or perhaps increase that charge?

Given -- you put that in conjunction with the fact that there is a cap on that charge that was at that incremental higher rate, so we've capped it at that rate, so rather than charging it off the gate, we said let's charge a lower charge, see if technologies evolve over time, see if -- how much solar ends up coming on the grid, let the marketplace unfold. If gas prices -- here's one where we agree -- if gas prices stay low, that helps keep the integration service charge down. So we're not using higher gas prices out into the future which would tend to increase the integration charge; we're using the lower gas prices.

So there's a lot of reasons where the integration charge is very distinct and separate from the actual energy value being created. And by putting it in at the average, it allows us to put it in at a much lower level, it allows the Commission to relook at this every couple of years and say is it still appropriate at this level, should I go up a little, down a little, and study this further, as opposed to locking this in for 10 years, or in the case of long-term contracts even longer.

So we think that this is a much better approach. It also does not pit one vintage of -- of QFs against another with respect to this. It is simply all QFs that have intermittency, solar QFs that have intermittency cause this cost and all share in the payment, and they can all through the addition, you know, and when they come on make a decision do I want to install a technology to offset it? So they -- they have both a cost cap. We've agreed to the cost cap. We've agreed to allow innovative QFs to find a way to not be subject to it. We've agreed to an average rather than incremental. So, again, I -- I think this has all been demonstrating that we're not trying to discourage here; we're simply recognizing a cost that many other jurisdictions are recognizing, as you add a large amount of intermittent resources, you have to have more operating reserves, and that comes at a cost.

Q I know we're going to get into issues of operating reserves and calculating this charge and -- and all those sorts of things with -- with Witness Wintermantel, so I will spare you those questions this afternoon.

A Much appreciated.

Q Sure. I do want to ask you just a little bit about the Figure 5 in your testimony. And I believe Mr. Smith asked you some questions about this, too. That's that variability chart that you include from a day in March.

A Page again? I'm sorry.

Q I don't have the page, but it's Figure 5.

A All right. I will find it.

Q I'm not going to ask you very detailed questions about it --

A Okay.

Q -- so I think you'll be okay.

A Go ahead while I'm looking. Yes.

Q Okay.

MR. DODGE: Thirty-five (35).

MS. BOWEN: Page 35. Thank you, Mr. Dodge.

Q So my understanding is you -- Duke operates to -- you have planning requirements and you have operating requirements, right? So you have your planning processes, which you're very involved in, the IRP process, those kind of processes, and then you have your day-to-day operations, your team that is -- that is operating the grid, yes?

A In real time, yes.

Q In real time. And they have to -- they have to comply with NERC -- NERC standards?

A That is correct.

Q Okay. And my understanding is the NERC standard -- we have this chart -- the example, I understand it's illustrative, you know, an example that you provided where it shows these different spikes, and it shows that even without solar you're having this variability back and forth all day long, right? That's what you're showing in this chart?

A Right.

Q And then with solar it just -- it increases the variability on each end?

A That's correct.

Q And my understanding is that the -- the NERC requirements -- complying with the NERC requirements don't require that you chase every single little blip, every single up and down; is that accurate?

A Yes, that's my understanding, and our -- and, again, Mr. Wintermantel can expand upon that, but the study did not assume you had to chase every single little blip.

Q Okay. And then one of the way -- well, and then the only -- I don't have many more questions, but I do want to ask you about ways to -- ways to address this variability, whether it be with -- without solar variability or with -- or adding solar variability. Are there things that Duke is doing to -- to address that beyond implementing a char--- you know, beyond the policy part of it in terms of implementing an integration charge, but in terms of operating the system?

A Yes. To my knowledge, and, again, I think this is key, is -- and, again, I'm going to leave the technical details --

Q Sure.

A -- to Mr. Wintermantel, but irrespective of how you supply those operating reserves, so there's lots of discussion as we read through all of this about, well, lean on your neighbors more, use more DSM, how about your hydro facilities, why don't you just have more violations -- or not violations -- why don't you just go a little deeper into the edge? The fundamental premise of the study, and I think this is key, is irrespective of what your standard is before you add solar, you want to leave the customer indifferent in a real-time reliability perspective after you've added solar. So no matter how I'm providing those services today, it's sort of irrelevant to, other than as we evolve technology, we can maybe find other ways to do it, but you don't want to be less reliable after you add the solar.

So if I'm using pump storage in a certain manner and leaning on the neighbors in a certain manner, however I'm doing that today, I do it with or without the solar. I shouldn't be asked to do more. Don't say, hey, go lean more on the neighbors or do something different in the change case that you didn't do in the base case. The base case and the change case have to have the same operational procedures, and then you say no matter how you assume you provide these services, how much more does it cost to provide them if you add more intermittency?

What the Intervenors seem to want us to do is to do something different in the change case than we're doing in the base case. Well, we're trying to do everything we can in the base case, and if we find better ways to, you know, to do that, we will, and as technologies change, as we retire certain plants, we bring new, more flexible plants online that will change the equation, but it needs to be the same both with and without solar.

And then the question you're answering is simply how much more does it -- do you need to carry and how much more does it cost if you do the same thing in the base and the change case?

Q And Mr. Snider, I know we're running a little long, so I am mindful of the time, but I did want to ask you on -- on that and something you just said in your answer about -- I think the phrase you used was deeper in the edge, but I think what you meant was looking at the standards that you're using, are they the right standards or should we be doing -- not even the right standards, but are we operating in the way that we need to to comply with the standards that we have to comply with, whether it be NERC standards or -- or something else. And I -- I don't know -- have you reviewed -- you've probably reviewed Mr. Kirby's testimony in this proceeding?

A Yes.

Q Okay. And --

A Briefly.

Q Okay. Thanks.

A Leaving most of that to Mr. Wintermantel.

Q Sure. Yeah. Understandable. And so you may or may not have seen this, but he attached in -- to his testimony -- it's labeled Exhibit D. It's a presentation from a staffer at Duke Energy Progress, Adam Guinn -- I don't know if you know him -- to NERC --

A Could I please have a copy?

Q Yeah. Absolutely. And it's attached -- I don't know if you have his testimony. You may not, but --

A I do not.

Q Okay. Sure. Let me get you to the right page, too. One second.

MR. BREITSCHWERDT: I see it. Thank you.

MS. BOWEN: Forgive me for --

THE WITNESS: No. That's fine. I'll hand it back when we're done. Thank you so much.

MR. BREITSCHWERDT: What page, please?

THE WITNESS: Nine (9).

Q Do you have the page? I just gave you my copy. Thanks.

A Nine (9).

Q Page 9. And, again, I'm not going to ask you very detailed questions about it. I know it's not your presentation. But it does -- it appears to me on this page and -- and I think one or two afterwards that you have a representative from Duke talking about the ways in which they are addressing variability and -- and trying to look at how they're implementing their practices and meeting the standards to see if they need to loosen their practices, for example, and still be compliant with this -- with the metrics that are imposed by NERC and otherwise. Do you -- I mean, does that -- is this one of the ways -- and the high level question for you, Mr. Snider, just is this one of the ways that -- this demonstrates Duke is trying to address this variability issue. Would you agree with that?

A Yes. And I think this just speaks to exactly what I was saying, that we're going to do this with or without solar, so we're looking for ways constantly to improve operations. And anything we do to improve operations, we're going to have a certain level of operating reserves we have to carry, no matter how we carry them. And when you add solar, you're going to have to carry more. Whether you do it slightly different from five years ago to five years from now, nothing changes the fact that when you add more intra-hour variability, you have to carry more operating reserves. That's a simple mathematical equation.

The question becomes how much more does it cost to carry those additional operating reserves? And that's where, you know, I've said if you're looking at the same level of intra-hour liability, base case and change case, as the world changes around you and another reason for updating every two years is that difference between the base case and the change case may change. We feel like the study we've done today -- and we've looked at it through lots of interrogatories, lots of discovery requests, a lot of different ways, not just the way we did it in the study. Go change it a little. Do this. Do that. What -- what we've determined is the cost that we've identified are appropriate under a fairly wide range of assumptions, so we're not putting our thumb on the scale in any way, shape, or form by the manner in which the study was conducted. It's simply recognizing that increased intra-hour volatility requires additional operating which has a cost.

And how you provide it, as long as you're maintaining the fact that -- and this is where I said it's critical, is you need to maintain the but-for principle that says I shouldn't be less reliable because of solar. No matter how I do it in the base case, I should maintain the same level of intra-hour reliability in the change case. And that's -- you know, that's the fundamental principle that's at question here. Should we or should we not have additional intra-hour risk as a result of intermittent solar. And I think that's the question before this Commission.

Q And Mr. Snider, sorry to interfere -- and then -- and that -- in terms of quantifying what that should be, that's what we'll hear from Mr. Wintermantel later in this proceeding?

A Correct.

Q Okay. Thank you. I have no further questions for you, Mr. Snider. I'll come and get that in just a minute. Yeah. Thanks. And then so quickly --

MR. LEVITAS: Do you have questions for --

MS. BOWEN: I do. I'm sorry. I know we're running a little long.

Q Mr. Johnson, I have just -- just a couple of questions for you, if that's all right. Okay. Hi, again. Lauren -- Lauren Bowen with Southern Environmental Law Center on behalf of SACE. Mr. Johnson, you acknowledge in your testimony that the existing Schedule PP Terms and Conditions, so those currently in place, don't limit or expressly address energy production shifting. Do you remember that in your testimony?

A (Johnson) Yes.

Q Okay. And supplemental at page 31. And then

-- and you actually pull a quote from the Terms and Conditions for the current standard offer. Do you remember that or quoting from it?

A I'm not sure. Could you --

Q Sure.

A Could you point me to the right page?

Q Yeah. Page 31 in your supplemental testimony.

A Is that the joint -- joint supplemental?

Q Yeah. One of the supplemental -- the joint supplemental. Wait. Hold on. Joint supplemental rebuttal. I'm sorry. Page 31.

A And so you're talking -- your question is about the standard PPA?

Q Yeah. That's right. And the quote you give is -- you're quoting from the Terms and Conditions for the standard PPA or standard offer that references -- and just the point I want to make, it references the annual kWh energy production. Do I have that right?

A I think it says the contracted estimated annual kWh energy --

Q Okay.

A -- production.

Q Okay. Thank you. And you argue in your testimony that it's unreasonable for QFs to both increase or to shift its output under the previously contracted four rates. Do I have that right?

A Yes.

Q And so even if that shifting doesn't change the annual kWh energy production, but changes when they're doing it. Do I have that right?

A Yes. I mean, our premise is that there was a contract executed by both parties, and there was a facility that -- that was built to -- to enable that contract to be fulfilled, and if that facility is subsequently changed and it -- and it causes a change in production or revenue, we feel like that's something that we have to give consent to.

Q So even if on -- if all -- if the changes are being made on the -- the physical changes are being made on the QF side of the meter or -- to put it that way, but what you're seeing on your side is a change in their production profile, for example, of when they're putting out electricity, even if they're under -- because -- because you're saying this for existing QFs, too, right, so even if they're under this previous PPA Terms and Conditions, they need to not do that or get approval from you or change their rates. Do I have all that -- do I have that right?

A Yeah. And I think --

Q Okay.

A -- in this testimony what we're talking about is existing PPAs that want to add storage, for instance, and that -- that storage, we feel like if it wasn't part of the original facility, then it requires our consent to add that storage.

A (Wheeler) Could -- could I elaborate on that?

Q Sure.

A Part of my responsibilities, I'm responsible for administering the Terms and Conditions on behalf of the Company, so I get involved with it quite a bit. A fundamental concept behind levelized rates is that the expectation is there that we'll have the same rough generation every year of the contract. When you levelize, you overpay in the early years. You pay a higher value than what it is to ratepayers, and the return in the later years you'll -- you'll actually underpay. It has a higher value to ratepayers, but the rate doesn't change over the fixed long-term contract.

So it's a fundamental ratemaking concept that you try to levelize, but the expectation is that the -- the amount of product we get in Year 1 will be roughly the same amount of product we get in Year 15, with the same rough load profiles as far as on-peak and off-peak consumption where generation is concerned. If you deviate from that, we view it as a material change in the operation.

Q So Mr. Wheeler, this may be a follow-up question for you or -- or for someone else on the Panel, but I think we heard Mr. Snider testify earlier today about some of the -- the benefits of renewable energy, including solar, and that we want to be encouraging it. It's generally good. Duke, you know, has programs to do such and is procuring it, as well as -- as the QF power that we see in North Carolina. Would you agree that one of the ways to better harness and use that renewable energy in terms of, you know, capturing more of those benefits is to add battery storage to a project?

A No. I wouldn't necessarily agree. As Witness Snider explained earlier, we -- we want to be more or less indifferent. When we set rates, we try to make certain that ratepayers are held harmless. If -- if we get the same amount of product in the early years as we do the later years, ratepayers are held roughly harmless based on our forecast what cost would be. That may be right or wrong, but that's not what we're trying to protect against.

If they -- if they produce less in the later years because they've shifted to a battery and we're not getting the same product delivered in the later years when we're actually underpaying for it, then ratepayers are harmed because they're not getting the same benefit over the term of the contract.

Q Well, we've talked about -- specifically, you are thinking about, in your context, avoided energy and avoided capacity rates?

A Yes.

Q Okay. And there are other benefits to renewable energy that -- that aren't captured in avoided energy and avoided capacity rates?

A To the extent we see a value to ratepayers from the -- a product being produced by the QF, we try to reflect it in the rates that we pay them.

Q Again, I don't know if this is back to you, Mr. Johnson, or not, but if we are able to capture more of the benefits of renewable energy to shift production times to when it's most needed on the system and by ratepayers to -- to peak energy times or peak demand times, if we can do that, do we ultimately potentially have some conservation of resources benefits from that? In other words, you're meeting -- you're meeting the potential for capacity needs, right, at a greater -- at a greater level if you are producing -- if you're putting out electricity at peak -- at times of peak demand. Would you agree with that?

A (Snider) Yes. I mean, there -- if you avoid capacity, it's fully reflected in the rate. We have capacity rates we just spoke about earlier that are much higher than in previous filings. It encourages the avoidance of that capacity at -- at the Utility's avoided cost. I think what we've said continually, though, is that's an indifference price. It doesn't create an inherent benefit to the consumer. It leaves the consumer indifferent. Unless the rates go down or maybe are calculated in a way that don't reflect the true indifference price, then the consumer could be harmed.

So we're just trying to -- to present a rate that leaves the consumer indifferent and not harmed. And, yes, if it's -- if the production happens across capacity hours, there's a higher payment paid to compensate the consumer for the avoidance of capacity. That's the fundamental intent of that -- that capacity payment.

Q For avoiding that capacity. And whichever one of you can -- it's my last question, but -- but it's just to confirm that the State of North Carolina has policies in place to -- and has legislative intent behind it to encourage conservation of resources in our state?

A (Snider) Yeah, in a very specific manner, and that's what we're trying to point out here, is that we think the right way to do that is in a manner that is beneficial to ratepayers and doesn't just leave them indifferent if the QF wants a long-term contract. Again, 589 says five years if you don't want to participate in competitive programs or longer than five years if you do want to participate in competitive programs that would allow you to sell your output for as much as 20 years, but the consumer should get consideration for that.

And in 589, again, three-legged stool. It says full environmental attributes, more control of the asset, and a cost not to exceed avoided cost, with a clear intent that the consumer would get it at below avoided cost. So what we're trying to avoid here is to sidestep 589's intent by offering 10-, 15-year contracts to storage that's being added, and then the consumer is paying for it at full avoided cost.

Q Well --

A And that's -- that's where we think that's not consistent with the intent you just spoke about in -- in

North Carolina's statute.

Q And forgive me, that was my last question, but I do need to ask a follow up, then. So my understanding is if you were going to require QFs to abandon their -- their contracts, they're not going to -- they're not going to -- they're not going to install storage if they're going to have to abandon their avoided cost rates, and so you're losing out on that benefit.

A Again, I would say are you -- are you losing out -- first of all, it's an indifference price. If they were to pay the full price, they're not getting it. They're -- they're at the indifference. You could get the same storage under 589. We have three tranches left. That same storage would come in at a lower cost for consumers. That was the clear intent of 589.

There is a finite need for four-hour batteries on our system. It's not infinite. It's not infinitely deep. How are we going to go get it? Are we going to get it by paying legacy contracts full avoided cost or are we going to go through a competitive procurement process to get that battery storage at competitively procured cost? I think that's the question at hand here.

And the -- the issue that I -- I really want the Commission to understand is that you can't just say we'll do both, because there's only so much -- as you do one, you're taking away from the other. There is only so much need for any resource on a utility system, whether it's solar, whether it's batteries, whether it's combined cycles, whether it's cogenerators. There is a finite need. And the Legislature, in my mind, has set a clear intent for long-term obligations on behalf of consumers, that they should see benefits. And I think that what we're talking about here is not against -- it's not anti-solar. It's not anti-storage. It's a question of how and at what price. And for us and our position, as articulated by the people on this Panel, is that that should be done -- if you want long-term fixed prices, it should be done through competitive procurement that extends those benefits. That's -- it's as simple as that.

Q Okay.

MS. BOWEN: I'm very sorry, Commissioner Mitchell. I do just have one follow-up.

Q And it is for Mr. Johnson, and it's just a yes or no confirmation. You can say subject to check if you want to. But subject to check, even this Commission has statutory authority vested with it to regulate public utilities, their rates, services, and operations, and their expansion in relation to the long-term energy conservation and management policies and statewide development requirements. Does that sound right to you, subject to check?

A (Johnson) Subject to check.

Q Okay.

MS. BOWEN: Thank you. That is all.

MS. HUTT: Maia Hutt from the Southern Environmental Law Center on behalf of SACE.

CROSS EXAMINATION BY MS. HUTT:

Q My questions are for you, Mr. Wheeler, and I promise there aren't many. So first, Mr. Wheeler, your testimony supports the solar integration charge Stipulation; is that right?

A (Wheeler) Yes.

Q And the Astrapé ancillary service study is the basis for the proposed charge contemplated in that Stipulation; is that right?

A Yes.

Q Have you reviewed the ancillary service charge study?

A Not in great detail. I understand the concept behind it. I understand the average cost rate basis. I understand the incremental cost basis used as setting rates.

Q Okay. That's fair. Are you familiar with this LOLE FLEX metric that is used in the study?

A I'm aware of loss of load expectation, yes.

Q And have you reviewed Mr. Thomas' testimony which was filed on behalf of the Public Staff and discusses the Stipulation?

A Yes, I have.

Q Okay. Mr. Thomas states that Duke and Astrapé conducted what sounds like a sensitivity analysis, whereby they used post-processing techniques to relax the LOLE FLEX metric from 0.1 to more flexible levels. Do you have any knowledge of those post-processing techniques?

A That's beyond the scope of my testimony.

Q Okay. Do you know -- does anybody else on the Panel have any knowledge of those post-processing techniques?

A (Snider) Mr. Wintermantel will be able to address that.

Q Okay. Great. And to your knowledge, has there been any information about those techniques filed with the Commission up until now, understanding that Mr. Wintermantel may be supplementing that?

A (Wheeler) I would defer to Witness Wintermantel.

Q Okay. Thank you.

MS. HUTT: That's all.

MS. BOWEN: Thank you, Madam Chair. We'll change seats so the witnesses don't have to look backwards.

CROSS EXAMINATION BY MR. LEVITAS:

Q Good afternoon, gentlemen. I'm Steve Levitas representing NCCEBA. Nice to be with you today. As with the other questioners, I'm just going to probably direct my questions mostly to Mr. Snider, but I hope other witnesses will jump in if you have something to add or if you're the best person to answer the question.

I want to start with --

MR. LEVITAS: Can you hear me okay?

COMMISSIONER GRAY: A little closer to the mic, please.

MR. LEVITAS: Okay.

Q I want to start with some follow-up questions on matters that have already been discussed, and then I'll turn my attention to my primary questions. So you indicated, Mr. Snider, that you have not yet calculated the 20-year avoided cost rate based on Duke's proposals in this proceeding, correct?

A (Snider) No, not -- not that we would be prepared to file as part of that.

Q So I -- I find that curious. You've talked at great length about the transition that the Legislature has made from a PURPA driven regulatory regime to a competitive solicitation program, and as a result of that, wouldn't you agree that the -- one of the primary uses and purposes of the avoided cost methodology and values that are being determined in this proceeding is to set the cap for the CPRE program?

A Yes. That was the clear intent of the Legislature, similar to PURPA, to say under no circumstance should customers pay more than the value created.

Q So don't you think it's a matter of interest to this Commission and to the parties to this proceeding to know what that 20-year rate is as they consider all the -- the variables and -- and factors that are at issue in determining that rate?

A Yeah. I think, as was recognized by this Commission, that several things have to happen to do that. One, the Commission has to rule on this rate. You know, what is the rate design that this Commission is going to approve? Is it the one in the Stipulation? We have Intervenors that have -- have questioned that rate design. What are they going to rule on the use of forward gas prices? There's several issues. What are gas prices going to do between now and when we file that rate? There are multiple things that are going to change that rate before we file that cap, some of which are market based and some of which are going to result as the outcome. So to me, I don't know how we could file a 20-year cost rate without knowing what the market is going to be at the time we calculate it and what this Commission is going to rule as a result of this proceeding.

Q Well, I understand that you can't derive a final rate until you know the answers to those questions, but you've -- you have submitted a proposed 10-year rate based on all of the positions that the Companies are taking with respect to the inputs on avoided cost, yet you have failed to disclose what those same inputs would produce on a 20-year basis, which is arguably the most relevant finding and -- and determination that will come out of this proceeding. What -- what's the basis for that?

A The basis for that is this is not a CPRE proceeding. The Commission had very specific guidelines as to what we're filing here. As -- as a matter of fact, I think the Commission is determining the standard offer rates. The Commission had a Scheduling Order that scheduled very specific technical issues that it wanted to hear expert witness testimony on.

If the Commission wanted a preliminary estimate based on the Company's original filing at some future gas price that the Company would determine at some point in time, they could have put that in their procedural schedule. That's not, to my understanding, the purpose of this docket. The purpose of this docket was to establish standard offer rates subject to all the specific technical issues that the Commission put in its Scheduling Order.

Q So if the Commission were to ask you to provide that information in this proceeding, would you be prepared to do so?

A Yeah, with appropriate guidance and time.

Q And is it -- is it possible that when you take all of the factors that you all are proposing with respect to revisions to the avoided cost rates and methodologies and inputs, that the 20-year rate is going to be significantly lower than the market prices that have been received to date in CPRE? Is that a possibility?

A I wouldn't say that's a possibility. I mean, it's --

Q No chance of that?

A I'm not saying no chance. I'm saying if you're saying is there any probability, yes. If you're saying is it likely, I wouldn't -- I wouldn't have a basis. I'll remind the Commission two things. One is you go out 20 years, you're giving that many more years of capacity value, so your capacity rate is going up. The Commission has already recognized that long-term gas prices are above short term, so you're going to use higher gas prices in a 20-year rate than you're going to use in a 10-year rate. So the rates that we're going to file are, by definition, going to be higher than the rates in this proceeding. How much higher? I have not calculated it based on today's gas prices. I don't know.

But to say that just because the 10-year rate is where it is, you have to recognize the 20-year rate that's going to set the cap is going to be higher. And, again, it points to that is the cap, and the risk associated with those 20-year gas prices are being compensated. The customer is being compensated by the three stools. It's getting something below avoided cost. It's getting the full environmental attributes, and it's getting operational control in exchange for the 20-year gas price risk that you're setting your cap at.

Q Well, thank you for that, Mr. Snider. I would respectfully submit that as the Commission considers the positions that you are advancing on all of the various elements that go into building up an avoided cost rate, that they might find it of great interest to know what -- the decisions that you're asking them to make will mean for the future of the CPRE program. So I -- I hope --

MR. BREITSCHWERDT: Objection. Chair Mitchell, I think we've had about a half dozen questions on how this is going to impact CPRE, and I think Mr. Snider has articulated that the focus of this proceeding generally was on establishing the standard offer avoided cost rates. The focus of the evidentiary proceeding that we're here for today was on discrete technical issues to develop that rate, so I haven't heard a question yet about any of those specific aspects. And Mr. Levitas, who works for Cypress Creek Renewables, who is a market participant and is interested in the rates that they would have to bid under in CPRE, it just seems like, one, this is beyond the scope and, two, it's becoming increasingly inappropriate. And clearly, he's set this up about three different times. If the Commission would like to know what that rate is, you certainly can ask, and that's not where we are.

CHAIR MITCHELL: Mr. Levitas?

MR. LEVITAS: May I ask one more question on this subject and then I'll move on?

CHAIR MITCHELL: One more question and move on, please.

Q So there's -- on these -- these different variables that we're all aware of that -- that contribute to the avoided cost rate, things like how gas prices are determined and summer/winter allocation and all the other variables that build up the rate, those are issues that different parties to these proceedings and people around the country disagree about. There's a range of possible outcomes. And in these proceedings you and we debate those and ask the Commission to make resolution of how those should be resolved. To date in these avoided cost proceedings, it's fair to say, is it not, that the Company has had concerns about the proliferation of uncontrolled QFs, the must put obligation, the effect that that was having on ratepayers and -- and your system? That's been a persistent theme, has it not?

A The overpayment that has happened as a result of ratepayers paying for QF above the avoided cost value being created, yes.

Q That's right. And so now that issue has, to a large extent, gone away with the migration to competitive solicitation, and so the use of these avoided cost calculations and those issues that we were just talking about contribute significantly to the viability of the Legislature's new CPRE program that largely has replaced PURPA, and so my question for you is why does the Company continue to take aggressive positions with respect to each of those issues that has the effect of driving the avoided cost rate down in a way that make -- may make the CPRE program nonviable?

MR. BREITSCHWERDT: Objection. I think it assumes facts that are not in evidence.

COMMISSIONER GRAY: Please speak up, sir.

MR. BREITSCHWERDT: I would say it assumes facts that are not in evidence, that it would make the CPRE program nonviable. That's based on assumptions that are not presented today, and I don't think that's a reasonable assumption to make.

MR. LEVITAS: If I didn't say has the potential to make the program nonviable, that was my intent.

WITNESS SNIDER: I'm okay.

CHAIR MITCHELL: All right. Please answer the question.

A (Snider) So the Company has done nothing to drive down. If anything, CPRE, again, we're trying to get the accurate -- in fact, nothing in House Bill 589 said go do this at any cost. The consumer protection was always a central component just like it was in PURPA, just like it is around the country. You're trying to implement this in a way that's fair to consumers. And because we have falling gas prices, because we have a large percentage of solar compared to other states, our avoided costs are dropping. And the fact that our avoided costs are falling and that we no longer have a summer need for capacity and that -- our winter need for capacity, that is simply the facts and circumstances as they exist.

And having sat through and watched the 589 process play out, I think what the Legislature was trying to say is don't go get solar at any cost. The very reason to put into that Legislation a 20-year cost cap -- and, again, it's a 20-year cost cap, not a five-year, not a 10-year, so you're using already very risky gas prices that may come in significantly lower; that's been the case for the last eight years, that gas prices have come in significantly lower than these long-dated projections -- has been to say, okay, we'll trade that risk, but it needs to be done in a manner that's competitively procured and has the benefits I've spoke about three times.

So the -- you know, the Legislature in no way intended for this to be go get this, and it seems like what Mr. Levitas is asking for here is he wants a results-oriented outcome from this Commission. Give me a number where I can ensure that I do business, and that's what this Commission's job should be. I don't view it that way. I think the Commission has, in its authority to set avoided cost, should do it at what value is being created for the consumer. And then if competitive procurement can come under that, great. We -- we welcome that. But it shouldn't be let's figure out through this process how we can determine the facts and circumstances so we ensure we have a results-based outcome that gets us competitively procured solar. That is not, I don't think, the intent of the Legislature.

So in arguing for why haven't we calculated so that we can ensure we get paid and we can bid under it, Mr. Levitas is asking for I want a number out of this process that guarantees, and I don't think that should be the objective, so we just have a fundamental, you know, difference of opinion that that should be the, you know, the objective of this Commission.

MR. LEVITAS: Well, I'm -- I do want to move on, but Mr. Snider, that is a gross characterization of my -- mischaracterization of my position and -- and my line of questions. It's -- in no way am I seeking a results-oriented outcome. I'm seeking, first of all, one that considers the outcome and, secondly, one that takes a balanced approach, given the new regulatory regime that we're operating under, rather than the aggressive and extreme approach that the Company has taken with respect to avoided cost, perhaps understandably, given its concern about PURPA proliferation.

CHAIR MITCHELL: All right. Mr. Levitas, let's stick to questions.

MR. LEVITAS: All right. I'll move on.

Q Again, just touching quickly on a -- more quickly on a few things that -- from the prior line of questions, Mr. Snider, you talked about the options available to expiring QFs, and specifically you mentioned the ability to bid into a new RFP. And my -- my question is, let's imagine that the Company has an identified need

for new capacity in 2028 and the QF existing PPA is
expiring in 2026, and the Company is deciding, let's say,
in 2024 what it's going to do to meet that capacity need
in 2028. What opportunity does a QF in that circumstance
have to compete to meet the capacity need that the
Company is trying to address four years out in 2024?

A Assuming it could meet the requirements of the
-- of the RFP, it has every opportunity. So let's take,
for example, an 80 MW solar facility in Mr. Levitas'
example. It expires in 2026. It's got a contract today.
That contract expires in '26. It is an existing QF, yes,
but it's also an existing merchant generator. That's an
existing merchant generator that can sell its output to
PJM. It can sell its output to Duke. It can sell its
output as a QF if it wants to establish a new LEO within
one year of its expiry, assuming PURPA doesn't change
over that time. Or if it -- if the Company had a peaking
need and said we need dispatchable resources, that QF
could say I'm going to add, you know, a battery behind
mine, and I'm going to bid my combined battery and solar
QF into that peaking resource need, assuming it met the
requirements of that -- of that need, and it could sell
it in '28. Or the Company may be looking for additional
renewables and have a renewable RFP out. 2028 is beyond

likely the expiry of Tranche 4.

So whatever RFP is out there, it's going to be for the facts and circumstances and needs at that point in time. And all I'm saying is that that -- that QF is more than a QF. It's a merchant power. It's established. It's interconnected. It's already been delivering power. It's likely largely financed and paid for. It has lots of options. And so that QF can -- can go down the QF path, as Mr. Johnson spells out in his testimony, and -- and establish and reiterate PURPA rights within one year of its expiry or it can bid into competitive procurements at Duke. It might -- there might be capacity or energy needs in PJM, in SCANA, or now Dominion South Carolina, and it could bid into those as an existing -- not just QF. But as an existing merchant power generator it has lots of options to sell it energy and capacity.

Q So Mr. Snider, can I infer from your answer that the Company does not intend to seek to build new generation resources in the future without going through a competitive solicitation process?

A In most cases we do do a competitive solicitation. There are special circumstances where you need a very specific type of energy at a very specific location for, let's say, a black start need or a specific regional need that you may have a much more focused market solicitation, but we generally do a pretty exhaustive process when we -- when we go through a CPCN which, again, I point out in testimony is a far more robust CPCN process than an existing QF has to go through.

Q Because the reason I ask is that -- that the scenario you described depends on there actually being an RFP for the QF to bid into.

A Right. And this Commission has the ability, when it goes through the CPCN process, to ascertain whether or not the Company did an adequate solicitation of the marketplace before it places new generation into service. And specifically, House Bill 589 says does the type of generation it's soliciting meet the particular type of need consumers have? So all generation is not equal. Sometimes you have a need for specific types of generation, peaking, dispatchable. Other times it's, okay, you're just looking for energy. It could be non-dispatchable energy only. But as long as the QF can meet the need identified, this Commission has the ability to say did you adequately consider it in an RFP process.

Q Thank you. You referred, in response to an earlier question, about your mandate to maintain your own operating reserves. Are you operating under a NERC mandate to meet the LOLE FLEX standard that's the metric used in the Astrapé study?

A I'm going to leave that question to Mr. Wintermantel.

Q Okay. Fine. I want to just talk a little bit about this idea of customer indifference. If I understood your testimony correctly, you're saying that if accurate avoided costs are paid, there's no benefit to the customer of receipt of a QF providing energy on peak or off peak. Was that your testimony?

A Yeah. That the customer does not get any additional value one way or the other from on versus off peak.

Q That seems to me a little like saying that -- that if I pay fair market value to eat at McDonald's, I'm getting the same value if I pay fair market value to eat at Second Empire. Isn't it the case that -- that the delivery, and I think Ms. Bowen was making this point, that the delivery of energy on peak is considerably more beneficial to the system and its customers than this delivery of massive amounts of off-peak energy that you all for years have talked about create such enormous problems for your system?

A I think what we're talking about is the difference between revenue and value. There's massively more revenue and cost associated with on peak, but the customer is not benefiting anymore from buying -- let's say I have two QFs. One can only produce from midnight, you know, until noon, and the other one can produce noon to midnight in the summer. Well, in the summer I'd like the noon to midnight, but if I'm pricing them both, one at 20 bucks and one at 50, the customer is indifferent. It's avoiding $20 energy at night and $50 in the day. So, yes, there's more -- the Company is getting something that costs more that's "more valuable," but the consumer is no better off because the Company could have provided that $50 power anyway. So they're getting an indifference price.

What creates customer value is buying something below your indifference price. So in your example the Company puts out McDonald's burgers and it puts out Second Empire filet mignon. And, you know, are you avoiding McDonald's burgers or filet mignon, because we would have made the burgers or the filet mignon either way. Now the QF is making the burgers or the filet mignon. The customer is not seeing any difference.

Q But if the energy is not provided on peak, you have to make -- you said you were able to do it -- you have to make other arrangements to do that, correct?

A That's the whole point of PURPA. We have other arrangements to do it, and we're pricing the avoided cost rate at that indifference price. So we're making one less filet mignon and the QF gets to make the filet mignon. The customer is getting filet mignon at 29.99 for his filet either way.

Q But price isn't the only issue, is it? In the case where you go to build new peak capacity because a QF is not providing it, should you have cost overruns, those are frequently borne by the customer. Should you have facilities that you own that go down, the customer is still paying for those facilities. In the case of QFs, neither of those things are the case. QFs bear all the construction risk and all the operating risk, so there is value, notwithstanding the fact that the price paid may be equal to the avoided cost.

A Yeah. Our current price paid for capacity is based on publicly available sources, which we've argued in the past are significantly above what we believe our -- our self-billed alternative is, so there is room for cost overruns and we're still below avoided cost. And if the facility goes down, we have an E4 or a forced outage rate built into the path. I mean, we are actually paying a benefit to the QF, recognizing that even traditional resources aren't a hundred percent available, so I think we've addressed both of those concerns in our rate design.

Q All right. Let me -- a couple more follow ups and then I want to move on to my primary line of questioning. There's been some discussion about the -- the storage additions and whether those constitute modifications, and -- and I understand the concern. The concern you very clearly expressed is that if you allow either additional energy to be generated or even shifting of energy, that there could be, under the current avoided cost rates, impacts to ratepayers that you think are undesirable. But isn't it the case that the answer to that question of whether those modifications should be allowed is a function of what those contracts say? I mean, the parties have entered into contracts, and either they're allowed under the contract to make the changes or they're not; isn't that right?

A I think -- and I'll let my counterparts at the table expand upon it. I think we're -- one of the material alteration definitions we're adding is to add clarity into what might have been an otherwise unclear concept, that adding additional energy in any time period, in any time bucket, as Mr. Wheeler explained, as Mr. Johnson explained, that when you're altering, you're changing the output of that facility, that was never envisioned under the original contracts. We produced additional language for the sake of clarity to say for new contracts let's just be clear on something that may not have been envisioned four or six years ago, but is -- is being questioned today. So we're adding that clarity to clarify what the contract we -- you know, we believe the intent of the contract was.

Q Well, I understand you think that that's the intent, but ultimately the intent will be determined by the four -- four corners of the agreement. And, in fact, you're making changes to those agreements because you have concerns that they don't say what you want them to say; isn't that right?

A No. We're clarifying what we believe they say.

Q Well, I understand --

A So that's not a change. I mean, you -- I think that's where we fundamentally disagree.

Q Well, if you're --

A I mean, and the Commission will help determine that.

Q If -- yeah.

A I mean, we -- we think it's -- it's a clarification. You think it's a fundamental change.

Q Well, no. I'm -- I'm prepared to accept there -- there may be a difference of opinion about which it is, but if there were no problem with the language of the existing contracts on this issue, you wouldn't have a need to make the changes. So -- and just -- I think these points were made by Ms. Bowen, but it is the case, isn't it, that the -- the standard offer contract, the current standard offer contract, which is enforced with respect to many facilities today, doesn't say anything about equipment modification, does it? Silent on the subject.

A (Wheeler) I would disagree with your characterization of that. When you fill out a PPA, a Purchase Power Agreement, you identify what facilities are being installed. If you change that, that's a fundamental change to the contract.

Q Well, I understand that's your position, but the --

A No. That's not my position. You have -- you fill out the contract and said I'm going to install solar. That's all I'm going to install. Now I'm going to install solar and battery and something else and something else or a cogeneration facility, it's a fundamental change to the contract. So it doesn't say you have to completely renegotiate the contract, but it does say you need our consent. We need to decide what's in the best interest to ratepayers.

Q Well, we'll let that speak for itself. I think the lawyers will sort that out, but I don't believe that it requires Duke consent to make equipment changes under the standard offer contract.

Let me -- let me shift gears a little bit, Mr. Snider. Has Duke calculated the total economic impact on existing and transition solar facilities of its proposed integration charge?

A (Snider) When you say "total economic impact," the total cost?

Q If the -- if the charges, as you're proposing them with the initial charge and the cap, which would be bounds, were to be implemented as you propose, what would be the total cost to existing solar facilities operating in the state today?

A I'm not sure if we did that as a data request or not, so I'd have to say subject to check, I think, you know, what we've said continually is we're not proposing to ask existing QFs to pay that today, so that's not a number that readily comes to mind. We've answered, I think, over 900 data requests, so I can't say that it hasn't been calculated.

Q Sorry. I wasn't totally clear with my question. My -- my question really is at the point of renewal when those charges become applicable to the existing facilities, what would the aggregate impact of that be to those facilities? And I'm going to ask you to just do a little math with me, if you would. These are -- Mr. Snider, this is just on a single page, two exhibits from Mr. Wintermantel's testimony from pages 21 and 25, Figures 4 and 5. Do you -- do you have a calculator handy?

A I do not. I'm pretty good with math, so go ahead.

Q Okay. Well, I want you to tell me if my -- if my methodology is correct. If we were looking to bound the impact on -- and this is the existing plus transition facilities, the best case scenario, I realize there could be some variation on this, but I think, roughly speaking, the best case scenario is if they would pay the initial charge over their full renewable term. And I -- I'm going to suggest for the purposes of discussion that these facilities have 15 years of remaining useful life, it would be three five-year renewals, so actually, I suppose the cap, which would only apply to the first five years, could be even higher, but I just wanted to look at the calculation of the initial charge on the low end and the cap on the high end, if we could have that conversation.

So if -- I believe the right methodology is to look in the third line from the bottom in each of these charts, which is the total number of hours being generated by these facilities. So in the case of DEC, that's 1.556 million. And you would multiply that times the charge of $1.10 in the case of the -- the base rate or 3.22 in the case of the cap, and -- and then you multiply that times 15 years. That would just give you a rough approximation. I'm not trying to say this is exact science. But when I do that math, here's what I come up with. It looks like the DEC initial charge would produce $25,679,000 in cost recovery from these facilities, and if the number were at the cap of 3.22, it would be over 75 million. In the case of DEP, the initial charge at 2.39, with a much higher output of the 5.6 million MWh, would result in $201 million of charges, and if the cap were to be hit, it would be $564 million.

Are you able just, roughly speaking, to confirm that those numbers seem about right?

A Yeah. I think those numbers over that life would be about right. The interesting thing is if they had 15 years left on their contract, they would get that much of a free pass on the first 15 years from not being included, so they're not even -- they're not even breaking even with customers. I mean, this is an avoided cost number that's a cost, so the numbers Mr. Levitas just pointed out are the cost being imposed. It's a good example of how much cost is being imposed on the system today that is being socialized.

So we can have the debate with Mr. Wintermantel as to whether this is the appropriate level or price, but for 15 years we have between 25 and $75 million of cross subsidization at DEC and between 201 and $564 million of cross subsidization at DEP for the existing. So the math is exactly right, and the fact that we're exempting existing customers or existing QFs from paying that, this math highlights how much subsidization is happening today for consumers having to pay for extra incremental operating reserves without it being a deduct to these existing QFs. This is being done in the backdrop of an over $2 billion existing overpayment just on the energy and capacity.

So, yes, while these numbers may seem large on what might happen 15 years from now, what is happening from now until those 15 years is those exact numbers are what the risk bands are for consumer overpayment for ancillaries that aren't in the existing contract.

Q Well, thank you, Mr. Snider. We'll -- we'll talk further today, and I'm sure with Mr. Wintermantel, about the accuracy of those numbers, but I'm really trying to make a different set of points because what's before this Commission at the moment is your proposal to impose those costs on -- on solar develop--- operating solar facilities. Now, I understand you think it's justified, you think it's good public policy and so forth, but the fact is it is a proposal. It is a public policy proposal to impose what could be as much in aggregate as $640 million on a group of businesses in this state, and so my question to you --

A I am not, though. We didn't -- we didn't suggest imposing it on existing.

Q Well, this is -- again, this is about when they -- upon renewal --

A If they renew --

Q -- if they renew --

A -- 15 -- if they renew for --

Q -- upon renewal that you have the potential for --

A -- Year 16 through -- yeah.

Q So my -- my point is, this is a very large impact on a group of businesses in this state. It may be justified, it may be good policy, but it's a big number. And I understand you're saying it's a big number on ratepayers, but the fact is we're at a -- at an inflection point on -- on policy, and we're making a decision about whether to do things differently than we've done in the past.

So my first question for you is wouldn't you agree that modeling of the sort done by Astrapé is inherently uncertain? It's modeling, right? All models are uncertain, correct? They have -- they have -- they have uncertainty, they have variables, assumptions, inputs that go in that could be right or wrong. They could cover a range of values, and whether you get them right or not is going to determine the accuracy of the model; isn't that right?

A It's fair to say that all modeling has some level of uncertainty. I would not disagree with that.

Q And are there ways in which the reliability of modeling of this sort can be increased to create greater certainty?

A I'm going to leave the technical details to Mr. Wintermantel. On the policy side what we did to, as I pointed out, to offset that uncertainty is we took a very conservative approach. We did not apply it starting Year 1. Had we done that, this would have been the cost we would have been asking for over the next 15 years, not Years 16 through 30. We implemented an average charge which is far less, as Mr. Wintermantel will testify to, than the incremental charge, which then is asking for the solar community to pay a much smaller charge out of the gate and leave the cross subsidization in for the next decade and a half to slowly phase out as we move out of existing. We think that's a very smooth transition. We think it's not taking a balance between customer overpayment and the impact on the QF community.

And so we did all of this from a policy perspective that is -- is really a very measured step into this integration service charge. It's not extreme. It's not reaching back and saying existing customers, you need to pay this. It's not going to the incremental charge. It's staying at that lower average charge. It's asking for it to be updated every two years so that as technologies evolve to hopefully offset this, that maybe we can help lower this charge over time. It's not asking for the long-term gas price which they benefit from on the energy side, but by staying short term, we're only using the short-term gas price which lowers that incremental charge.

So if gas prices don't go up, this incremental charge stays low. Now, we're still going to way overpay for the energy, but we're going to not have to pay -- the QF is not going to have to pay for that increase in what we would have projected had we asked for a 15-year or 10-year or 15- or 20-year fixed integration charge. So there are many structural ways in which we implemented the rate that were intentionally designed to balance this risk that Mr. Levitas is speaking to. We could have done five different things to make this much more aggressive, and we get characterized as being aggressive when we're simply trying to identify cost causation, and then implement that in a way that -- that is measured and balances the QF interest with the customer interest.

Q I understand there are some things that you have done that you've described as measured or balanced with respect to the way you've chosen to implement the charge, and I commend you for those and we appreciate that. That's a different issue than the level of certainty and confidence in the values themselves, because if you have numbers that -- that are way off, as experts on our side have said, and then you say, okay, well, we'll implement them in a conservative way, that may not wind up being a very good outcome for the people who are paying those charges. So let me ask you this --

MR. BREITSCHWERDT: Chairman?

Q -- do you -- do you have -- do you have a -- have you done any kind of sensitivity analysis on the results of the Astrapé model to -- to derive a confidence level in its results?

A I'm going to let Mr. Wintermantel -- I know we did several different sensitivities and looked at several different alternative approaches. There was a lot of comparing done to other studies nationally. There's lots of different ways you can sort of look at this to say what's the reasonableness of it. Some of those details, I think, are addressed by Mr. Wintermantel, so I'm going to let him --

Q Okay.

A -- fully --

Q Fair enough.

A -- expand upon that.

Q I'll be happy to talk to him about that, but let me ask you this question since it relates to your company. Are -- are you aware that your company has had to deal with issues relating to the potential impact of leachate from coal ash ponds on groundwater?

MR. BREITSCHWERDT: Objection. I fail to see how this is within the scope of the issues that the Commission has noticed for hearing in this proceeding or how it relates to avoided cost.

MR. LEVITAS: Well, it -- it relates to this issue precisely because it goes to the Company's past expectations with respect to the degree of confidence that should be brought to bear on statistical analysis and modeling, which --

CHAIR MITCHELL: I'm going to sustain the objection.

MR. LEVITAS: Then I will move on.

Q So let me ask you about -- another question, peer review. Was there any peer review conducted of the Astrapé study?

A It was compared to other studies done nationally, and it was looked at from the perspective of what internal analysis, as we begin to develop these sub-hourly, might have expected. So, yeah, I think it was -- it was compared to other studies quite a bit throughout this. Again, I think we answered individual parts to questions of over 900 different interrogatories by parties. We made every attempt to do additional analysis. So I think this was -- was not only reviewed in great depth and there was a great amount of effort and work not only in producing the study, but then defending it through this process. There was significant effort to -- to do additional work, do additional model runs to get a feel for -- for what the result is and how it will respond to different inputs. So I think this -- this study -- and, again, there was a significant effort in the PNNL study done back in Sub 140, and these results are not out of line by orders of magnitude which -- with what came up back then at just a high level, from just a, you know, an outside looking in from -- from this Commission. So there was a lot of review done to this study throughout this process. A tremendous amount of work went into the study. A tremendous amount of work went into providing Intervenors, Public Staff, and other Intervenors with additional analysis.

So, yes, I think this model has been reviewed, you know, for a $1.10 integration charge at DEC and a

$2.39 cent average integration charge at DEP; I think this model has been probably more reviewed than -- than general rate cases.

Q Well, excuse me, Mr. Snider. Reviewed by whom?

A Reviewed by Intervenors, reviewed by the Public Staff, reviewed by as -- the Commission will have a body of evidence on this -- through the amount of interrogatories that have been filed, testimony, rebuttal -- four rounds testimony, significant reply comments all addressing this, and significant interaction with the Intervenors.

So it's not like we just filed it and said take it or leave it. We worked diligently to allow this to be reviewed. We tried to make our experts available, at the Company's expense, to run additional analysis. We've had -- this study has been compared to other studies extensively, so I think this, you know, this study, again, is -- is a very defendable study. It gives a very measured approach. And I think, you know, we'll -- we'll let the Commission work through the record as to whether or not it's -- it's had adequate review.

Q The Merriam-Webster Dictionary defines peer review as a process by which something proposed as for research or publication is evaluated by a group of experts in the appropriate field. So when I talk about peer review, I mean was there an independent group of experts who reviewed this report, this study, to validate the results that were reached by Astrapé?

A Yeah. Public Staff has professional engineers on staff that have reviewed it. Our company has statistical experts internally that reviewed it, thought it was -- it was appropriate. You know, Intervenors simply don't like the results, so they're saying it's not been reviewed and --

Q Well, I -- I object --

A -- if -- if the standard is going to be that we need to hire three consultants, have them do it all independently, present three different consultant results, then -- then, no, we didn't hire three different consultants. But this comports with a very extensive PNNL study, it comports with other studies being done around the nation. It stands up to Public Staff review. It stands up to our internal quantitative analyst review. So, yes, I think it's been reviewed. Maybe you're talking more about in scientific literature has it, you know, been peer reviewed before being published in a journal? No.

Q Okay.

MR. LEVITAS: Well, I -- I take issue with your suggestion that our eminently qualified experts who did do in the nature of peer review of this report and -- and identified serious problems and objections, just didn't like the results. They are extremely respected experts in their field and exactly the sort of parties --

MR. BREITSCHWERDT: Objection. Is there a question?

MR. LEVITAS: Well, I'm -- I'm not going to allow the witness to mischaracterize the testimony provided by our witnesses. I'll move on.

Q Let me talk about another aspect. And, again, recognizing that there's 600 plus million dollars at stake of cost potentially being imposed on businesses in the --

MR. BREITSCHWERDT: Objection. Is there a question?

MR. LEVITAS: I'm about to ask a question.

MR. BREITSCHWERDT: Thank you.

MR. LEVITAS: I'm moving on to a new question.

Q So with respect to stakeholder involvement, what did the Company do in the course of designing this study to reach out to parties that would be affected by its results to seek their input in advance and to work on achieving consensus around the design of this study?

A Are you explicitly saying did we approach the solar community and ask them to design the study?

Q To work with you collaboratively, as we have on many other issues, to try to reach consensus about how this study should be designed and conducted.

A No, we did not.

Q And if the Commission were contemplating making a regulatory change that would have a $600 million impact on Duke Energy, wouldn't you expect to be consulted about study design in advance?

A I guess, you know, it's a fundamental question before this Commission if all planning is now going to be -- you know, the Utility is the legal entity with the obligation to serve and the obligation to bring this case forward, and so that's what we've done. We presented -- we try to be extremely transparent. We've made our consults available. We've answered, like I said, hundreds upon hundreds of interrogatories. We've done additional analysis. We believe that approach is very appropriate as the party bringing forth the rates, the ones responsible to maintain reliable, affordable electric service and, you know, every single study we do within the Company simply cannot be done through a huge collaborative process. This is not -- we're talking about, as Mr. Levitas points out, 15 years from now the potential for 225 million to over 600 million that could happen a decade and a half from now in light of a known multibillion dollar overpayment today with a zero cost being ascribed to existing, so for the next 15 years no cost for this -- for these services.

So, you know, no -- the fact that we did not go through a large collaborative process on this one particular study I don't think in any way indicts the study or in any way invalidates its legitimacy.

CHAIR MITCHELL: All right. Mr. Levitas, we've come to the end of the day today. We will be back in the morning at 9:30. Please plan on a lunch recess that's limited to one hour. We'd like to spend as much time in the hearing room as we can tomorrow. So 9:30. We will go until 5:30 again tomorrow as well. And we are adjourned. Thank you.

(The hearing was recessed, to be reconvened
on July 16, 2019 at 9:30 a.m.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-100, Sub 158, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 23rd day of July, 2019.

Linda S. Garrett

Linda S. Garrett, CCR

Notary Public No. 19971700150