PLACE: Dobbs Building, Raleigh, North Carolina



DATE: Tuesday, April 18, 2017

TIME: 9:30 a.m. - 12:27 p.m.

DOCKET NO: E-100, Sub 148

BEFORE: Chairman Edward S. Finley, Jr., Presiding
Commissioner Bryan E. Beatty
Commissioner ToNola D. Brown-Bland
Commissioner Don M. Bailey
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Lyons Gray

**IN THE MATTER OF:**

General Electric

Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2016

VOLUME: 2

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

E X H I B I T S

P R O C E E D I N G S:

CHAIRMAN FINLEY: Good morning. Let's come to order and go on the record. I am Chairman Edward Finley, and with me this morning are Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson and Lyons Gray.

I now call for hearing Docket Number E-100, Sub 148, In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities 2016. These are the 2016 biennial proceedings held by this Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policy Act of 1978 and applicable Federal Energy Regulatory Commission regulations pertaining to the Commission's responsibilities for determining each electric utility's avoided costs with respect to rates for purchases of power from qualifying co-generators and small power production facilities.

These proceedings are also being held pursuant to G.S. 62-156, which requires this Commission to determine the rate to be paid by electric utilities for power purchased from small power producers as defined by G.S. 62-3, Sub (27a).

On June 22, 2016, the Commission issued its

Order establishing biennial proceeding, requiring data, and scheduling public hearing. Pursuant to the Order, Duke Energy Carolinas; Duke Energy Progress; Virginia Electric and Power Company, d/b/a Dominion North Carolina Power; Western Carolina University; and New River Power and Light Company were made parties to these proceedings.

The following parties have filed Petitions to Intervene that have been granted by the Commission: the North Carolina Sustainable Energy Association; The Public Works Commission of the City of Fayetteville; Carolina Utility Customers Association, Inc.; The Carolina Industrial Groups for Fair Utility Rates I, II, and III; Southern Alliance for Clean Energy; Strata Solar, LLC; North Carolina Pork Council; NTE Carolinas Solar, LLC; Cypress Creek Renewables, LLC; O2 EMC, LLC; and North Carolina Electric Membership Corporation. Participation of the Public Staff has been recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). Pursuant to G.S. 62-20, the North Carolina Attorney General's office gave notice of intervention on April 11, 2017.

On November 15, 2016, Dominion filed avoided cost information along with initial comments and exhibits. Dominion amended its avoided cost information on November 16 with corrected on-peak-load numbers. Also, on November 15, 2016, DEC and DEP filed Joint Initial Statements and exhibits.

On November 28, 2016, Western Carolina University and New River Light and Power Company filed proposed avoided cost rates.

On December 20, 2016, Intervenor NCSEA filed a Motion to Strike as irrelevant to the proceeding certain materials in the proposals of DEC, DEP and Dominion. An Order denying NCSEA'S motion was subsequently issued on January 18, 2017.

On December 22, 2016, the Public Staff filed a Motion for Amended Procedural Schedule and, according to a request by DEC and DEP, the addition of an evidentiary hearing to be scheduled was made.

On December 30, 2016, the Commission issued an Order Scheduling Evidentiary Hearing and Amending Procedural Schedule, and setting the evidentiary hearing at 9:30 a.m., on this date in this place.

On January 17, 2017, DEC and DEP filed confidential avoided cost information.

On or before February 15, 2017, all electric utility companies filed Affidavits of Publication of

Notice of Hearing, and the public hearing was held in this hearing room on February 21, 2017, as scheduled. Twelve witnesses gave testimony at the public hearing. In addition, over 1,000 consumer Statements of Position have been filed in this docket.

On February 21, 2017, Dominion filed the direct testimony of J. Scott Gaskill and Bruce Petrie. Also on February 21, DEC and DEP filed the testimony with exhibits of Lloyd Yates, Kendal Bowman, Glen Snider, John Holeman, III, and Gary Freeman.

On March 28, 2017, NCSEA filed the testimony and exhibits of Carson Harkrader, Ben Johnson and Kurt Strunk; Cypress Creek filed the testimony of Patrick McConnell; and SACE filed the testimony and exhibits of Thomas Vitolo, Ph.D. On the same date, NCEMC filed initial comments. The Public Staff filed direct testimony and exhibits of John Hinton, Jay Lucas and Dustin Metz.

On April 8, 2017, Dominion filed the rebuttal testimony of witnesses Gaskill and Petrie and DEP and DEC filed the rebuttal testimony of witnesses Bowman, Snider, Holeman and Freeman.

Pursuant to Statute, I remind all members of the Commission of their duty to avoid conflicts of interest and inquire whether any member of the Commission has a known conflict of interest with regard to the matters coming before the Commission this morning?

(No response.)

There appear to be no conflicts so we will proceed with recognition of counsel, beginning with the companies.

MS. FENTRESS: Good morning, Mr. Chairman, Members of the Commission, I'm Kendrick Fentress and I'm appearing on behalf of Duke Energy Carolinas and Duke Energy Progress.

MR. BREITSCHWERDT: Mr. Chairman, Members of the Commission, Brett Breitschwerdt with the Law Firm of McGuireWoods on behalf of Duke Energy Carolinas and Duke Energy Progress.

MR. SOMERS: Good morning, Mr. Chairman and Commissioners, Bo Somers, Deputy General Counsel, on behalf of Duke Energy Carolinas and Duke Energy Progress.

MR. KAYLOR: Good morning, Mr. Chairman and Members of the Commission, Robert Kaylor on behalf of Duke Energy Progress and Duke Energy Carolinas.

MR. ALLEN: Mr. Chairman, my name is Dwight

Allen. I'm an attorney in Raleigh and I'm also appearing on behalf of Duke Energy Progress and Duke Energy Carolinas.

MS. KELLS: Good morning, Mr. Chairman and Commissioners, Andrea Kells with McGuireWoods appearing on behalf of Dominion North Carolina Power. Also appearing on behalf of Dominion is Mr. Bernie McNamee with McGuireWoods whose been admitted pro hac vice for this proceeding. And with us today, also, is Mr. Horace Payne, Senior Counsel with Dominion.

CHAIRMAN FINLEY: Long time no see, Mr. McNamee.

MR. MCNAMEE: Thank you.

MR. CULLEY: Good morning, Mr. Chairman, and Commissioners, Thad Culley with the Law Firm of Keyes & Fox. I'm here on behalf of Cypress Creek Renewables.

MR. LEDFORD: Good morning, Mr. Chairman and Commissioners. My name is Peter Ledford on behalf of the North Carolina Sustainable Energy Association.

MS. MITCHELL: Good morning, Mr. Chairman and Commissioners. My name is Charlotte Mitchell appearing on behalf of the North Carolina Sustainable Energy Association.

MS. BOWEN: Good morning, Mr. Chairman and Commissioners, I am Ms. Lauren Bowen with the Southern Environmental Law Center here today on behalf of Southern Alliance for Clean Energy, and with me are two of my colleagues, Peter Stein and Gudrun Thompson.

MR. DODGE: Good morning, Mr. Chairman and Members of the Commission, I'm Tim Dodge with the Public Staff. We represent the Using and Consuming Public in this proceeding. Appearing with me today is Robert Josey and also appearing during the hearing will be Heather Fennell and Lucy Edmondson.

MR. PAGE: Mr. Chairman and Commissioners, Bob Page representing Carolina Utility Customers Association.

MS. HARROD: Mr. Commissioner and Commissioners, my name is Jennifer Harrod, here on behalf of the North Carolina Attorney General's office in the interest of consumers. Thank you.

MR. YOUNG: Good morning. I'm Michael Youth with the North Carolina Electric Membership Corporation.

MR. OLLS: Good morning, Mr. Chairman, Commissioners, my name is Adam Olls, here on behalf of Carolina Industrial Group for Fair Utility Rates I, II, and III.

MR. STYERS: Mr. Chairman and Commissioners, I'm Gray Styers with the Law Firm of Smith Moore Leatherwood, appearing on behalf of NTE Solar, LLC.

MR. OLSON: Good morning. I'm Kurt Olson and I'm appearing on behalf of the North Carolina Pork Council.

CHAIRMAN FINLEY: Let me see counsel up here a minute.

(OFF THE RECORD DISCUSSION)

CHAIRMAN FINLEY: Anything that we need to do before we begin taking testimony?

(No response.)

Companies, who goes first?

MR. SOMERS: Thank you, Mr. Chairman, we would like to call our first witness, Mr. Lloyd Yates to the stand.

CHAIRMAN FINLEY: All right.

**LLOYD M. YATES**; was duly sworn and testified as follows:

DIRECT EXAMINATION

BY MR. SOMERS:

Q Good morning, Mr. Yates. Would you please state your name for the record?

A Lloyd M. Yates.
Q What is your business address?
A 550 South Tryon Street, Charlotte, North Carolina.
Q What is your position with Duke Energy?
A Executive Vice President of Customer and Delivery Operations; President of Carolinas.
Q And with that position what is your responsibility for Duke Energy Carolinas and Duke Energy Progress?
A So two primary responsibilities - I have profit and loss responsibility for Duke Energy Progress and Duke Energy Carolinas and have operational responsibility for all customer and distribution operations across the enterprise.
Q Thank you, Mr. Yates. Did you cause to be prefiled direct testimony in this case of some approximately 12 pages?
A Yes.
Q And do you have any changes or corrections to your prefiled direct testimony?
A I do not.
Q So, if I were to ask you the same questions as written in your prefiled direct testimony here

today from the stand, would your answers be the same?

A They will.

MR. SOMERS: Mr. Chairman, at this time I would ask that Mr. Yates' prefiled direct testimony be entered into the record as if given orally from the stand.

CHAIRMAN FINLEY: Mr. Yates' direct prefiled testimony filed on February 21, 2017, consisting of 12 pages is copied into the record as though given orally from the stand.

MR. SOMERS: Thank you, Mr. Chairman.

(WHEREUPON, the prefiled direct testimony of **LLOYD M. YATES** is copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

| | | |
|---|---|---|
| In the Matter of | ) | **DIRECT TESTIMONY OF** |
| Biennial Determination of Avoided Cost | ) | **LLOYD M. YATES** |
| Rates for Electric Utility Purchases from | ) | **ON BEHALF OF DUKE ENERGY** |
| Qualifying Facilities – 2016 | ) | **CAROLINAS, LLC AND DUKE** |
| | ) | **ENERGY PROGRESS, LLC** |

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

A. My name is Lloyd M. Yates, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am Executive Vice President, Customer and Delivery Operations and President, Carolinas Region for Duke Energy Corporation ("Duke Energy").

**Q. WHAT ARE YOUR JOB RESPONSIBILITIES?**

A. In this role, I am responsible for the strategic direction and performance of Duke Energy Carolinas, LLC ( "DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies"), our regulated utilities in North Carolina and South Carolina. I am also responsible for leading Duke Energy's delivery of customer-focused products and services to deliver a personalized end-to-end customer experience that positions Duke Energy for long-term growth.

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.**

A. I earned a Bachelor's degree in Mechanical Engineering from the University of Pittsburgh and a Master of Business Administration degree from St. Joseph's University in Philadelphia. I also attended the Advanced Management Program at the University of Pennsylvania Wharton School and the Executive Management Program at the Harvard Business School. I have more than 30 years of experience in the energy industry, including the areas of nuclear generation, fossil generation, and energy delivery. I previously served as executive vice president of regulated utilities for Duke Energy, where I had responsibility for the company's utility operations in six states. I also had responsibility for federal government affairs, as well as environmental and energy policy at the state and federal levels. As executive vice president of customer operations for Duke Energy, I led the transmission, distribution, customer services, gas operations, and grid modernization functions to approximately 7.2 million electric customers and 500,000 gas customers. Prior to the Duke Energy/Progress Energy Corporation merger in July 2012, I served as president and chief executive officer for Progress Energy Carolinas. I was promoted to that position in July 2007, after serving for more than two years as senior vice president of energy delivery for Progress Energy Carolinas. Prior to that, I served as vice president of transmission for Progress Energy Carolinas. I joined the Progress Energy predecessor, Carolina Power & Light, in 1998, and served for five years as vice president of fossil generation. Before joining Progress Energy, I worked for PECO Energy for 16 years in several line operations and management positions. I also serve on several community, state, and industry boards. In 2014, I was elected president and chairman of the Association of Edison Illuminating Companies. I am also a director for Marsh & McLennan Companies Inc., a global professional services firm.

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

A. Yes. I have testified before this Commission on numerous occasions over the years in rate and other utility matters, including most recently in DEP's 2013 general rate case proceeding, Docket No. E-2, Sub 1023.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony in this proceeding is to explain why Duke Energy believes that North Carolina is at a critical crossroads regarding the integration, development, and customer costs of renewable generation. This crossroads is particularly critical for solar generation. I also provide an overview of DEC's and DEP's requested changes in this biennial avoided cost docket that will promote a smarter, sustainable renewable energy future for our State. The Companies are also presenting the direct testimony of Witnesses Kendal Bowman, Vice President, Regulatory Affairs & Policy, who testifies regarding the Public Utility Regulatory Policies Act ("PURPA") and our proposed changes to how the Commission should implement PURPA in North Carolina; Glen Snider, Director, Integrated Resource Planning & Analytics-Carolinas, who testifies to the Integrated Resource Plan ("IRP") basis for the Companies' proposed avoided cost rates, terms, and policies; Sam Holeman, Vice President, Transmission System Planning and Operations, who testifies to the significant operational challenges that DEC and DEP face in response to the current state of significant, uncoordinated and unconstrained solar additions to our State's energy grid; and Gary Freeman, General Manager, Duke Energy Renewables Compliance, Origination, and Operations, who testifies to the Companies' position on evolving the Commission's legally enforceable obligation policy.

**Q. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY NORTH CAROLINA IS AT A CRITICAL RENEWABLES CROSSROADS.**

A. Duke Energy and the State of North Carolina are national leaders in renewable energy. Both DEC and DEP have achieved long-term compliance with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") solar carve-out, and, as of August 2016, DEP has contracted for sufficient renewable energy certificates ("RECs") to achieve full REPS compliance through at least 2028. Since 2007, Duke Energy has invested approximately $5.8 billion in renewable generation projects, including nearly $300 million by DEP and $175 million by DEC in North Carolina. In 2014, Duke Energy issued a request for proposals ("RFP"), targeted at solar facilities greater than 5 MW, which resulted in a $500 million solar expansion commitment through acquisition and construction of new North Carolina solar facilities and execution of new purchase power agreements ("PPAs") with additional solar projects in North Carolina. More recently, on October 24, 2016, DEC issued an RFP for 750,000 megawatt-hours ("MWh") of renewable energy and associated RECs located in the DEC territory to encourage development of more renewable generation in the most competitive manner possible, giving developers the opportunity to either pursue projects themselves or sell current projects under development to DEC. Today Duke Energy has more than 35 solar plants that are 1 MW or greater in North Carolina. DEP owns and operates nearly 140 MWs of solar generation in North Carolina, while DEC owns and operates nearly 9 MWs of solar generation with an additional 75 MWs under development.

As a result of regulatory and legislative policies, strong support by DEC and DEP, and aggressive construction and deployment of solar facilities by developers, North Carolina is second only to California in interconnected solar capacity. As of December 31, 2016, there are more than 1,600 MW of third-party developed solar connected to DEC's and DEP's grid in North Carolina, with another 4,900 MW progressing through the interconnection queue.

This unprecedented growth in interconnected and proposed solar generation in just the past few years has also created challenges that put our State at a crossroads. Existing policies, which have resulted in unconstrained growth in solar generation, have created a distorted marketplace for solar projects that have resulted in artificially high costs that are inevitably passed onto North Carolina residents, businesses, and industries, while potentially degrading operation of the Companies' electric systems. These policies have created a larger and more rapid utility-scale solar growth and now need to be reevaluated to allow for a smarter, more sustainable and economic approach.

**Q. WHAT ARE THE FINANCIAL IMPACTS OF NORTH CAROLINA'S CURRENT PURPA POLICIES ON DUKE ENERGY CAROLINAS' AND DUKE ENERGY PROGRESS' CUSTOMERS?**

A. The overwhelming majority of solar generation plants in North Carolina are developed under the provisions of PURPA. In fact, 60% of all installed PURPA solar projects in the entire United States are located in North Carolina. As a general rule, DEC and DEP have historically had little influence on the volume or location of these projects on the utility system. This has created a distorted marketplace, in part, because the price and terms the Companies are mandated to offer to those projects are significantly more generous to solar developers than those offered by other utilities and states. North Carolina has "significantly encouraged" solar development under PURPA compared to our peer states. As discussed in more detail by Witness Glen Snider, because of the trend in declining energy markets over the past several years, actual incremental energy costs have been significantly lower than prior forecasts in earlier avoided cost filings. DEC and DEP have long-term PPAs with Commission-set avoided cost rates ranging from \$55 to \$85 per MWh, while the Companies' current actual system incremental "avoided" costs are approximately \$35 per MWh. As Mr. Snider details in his testimony, the Companies and our customers are paying approximately \$80 million annually, or nearly \$1 billion in total, more to solar developers than their actual avoided costs over the remaining life of the existing contracts. As a result, our customers are exposed to the significant risk and burden of excess avoided cost rates under the current framework.

**Q. WHAT ARE THE PLANNING AND OPERATIONAL IMPACTS TO DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS FROM THE CURRENT UNCOORDINATED AND UNCONSTRAINED SOLAR DEVELOPMENT IN NORTH CAROLINA?**

A. DEC's and DEP's primary public service mission and statutory obligation is to provide safe and reliable energy to our customers at reasonable rates. Reliably planning and operating the Companies' systems is becoming increasingly challenging as the level of variable, non-dispatchable utility-scale solar continues to surge. As the Commission is aware, under the current PURPA requirements and process, DEC and DEP are required to interconnect and purchase from qualifying facilities ("QFs"), with minimal input on need, location, timing, or size of the QF facility. Unlike Company-owned generation or non-QF wholesale generation, the Companies have no ability to dispatch, and only limited emergency rights to curtail, QF generators. This inhibits the Companies' ability to maximize the reliable and economic operation of the energy grid. As Witness Holeman discusses in more detail in his testimony, the generation, transmission, and distribution systems must adjust minute-to-minute and even second-to-second to meet constantly fluctuating customer demand. PURPA regulations do not allow for effective real-time control of QF generation, which creates operational impacts when significant QF generation, especially significant variable and intermittent QF solar generation, is added to the system. The Companies have gained significantly greater experience over the past 18 months with the real operational impacts of the surging development of PURPA-driven utility-scale solar generation on the DEP and DEC systems. In particular, this proceeding represents the Companies' first opportunity in a biennial avoided cost proceeding to inform the Commission regarding the detrimental impacts to the DEP system after approximately 1,000 MWs of variable, non-dispatchable and non-curtailed utility-scale solar generation has come online – overwhelmingly in 5 MW increments on rural distribution feeders in Eastern North Carolina. Mr. Holeman details how the continuing surge in utility-scale solar QF generation is increasingly challenging how the Companies plan and operate their generation fleets, manage their transmission systems, and assure reliable power is delivered to our customers over local distribution circuits on a minute-by-minute basis. Unless thoughtful solutions are implemented to address the current situation, the number, severity, and consequences of these challenges are expected to increase as the level of variable and non-dispatchable solar energy increases.

**Q. WHAT SOLUTIONS ARE DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS PROPOSING TO ADDRESS THE CURRENT SITUATION?**

A. Duke Energy supports a transition to a smarter, sustainable renewable energy future for our State. As discussed by Witness Bowman, current regulatory and economic drivers necessitate a comprehensive review of the Commission's PURPA policies to ensure the long-term viability and integration of additional solar and other renewable resources for the benefit of our State and our customers. We believe that addressing the consequences of the current unmanageable PURPA-driven solar marketplace will require a revised, comprehensive approach. Some solutions are within the Commission's authority, and some will likely require other policy changes.

As discussed in the Companies' Joint Initial Statement and by Witness Bowman, DEC and DEP are proposing a competitive bidding process, which would ensure that the most attractive, most cost-efficient projects are built, helping further ensure a more orderly addition of new solar power onto the Companies' systems. As part of the competitive bid process, the Companies would acquire dispatch and curtailment rights to mitigate the detrimental operational impacts the current system threatens. Further, as discussed in the testimony of Ms. Bowman, the Companies are proposing the following major changes to the Commission's traditional PURPA standard contract policies:

(1) Capping eligibility for DEC's and DEP's proposed standard Schedule PP avoided cost tariff at 1 MW;

(2) Evolving DEC's and DEP's long-term standard Schedule PP tariffed rates to a single standard 10-year long-term rate offering with a fixed, levelized capacity component and biennial updates to the energy component to be reestablished every two years in future avoided cost proceedings;

(3) Calculating value for "needed capacity" in a manner that recognizes the first year in which DEC and DEP show an actual need for incremental capacity;

(4) Reducing the Performance Adjustment Factor from 1.2 to 1.05 to align better with the reliability of traditional capacity that would be avoided;

(5) Amending the Companies' standard contract terms and conditions to incorporate compliance with mandatory and enforceable North American Electric Reliability Corporation and SERC Reliability Corporation regulations and standards within the "emergency conditions" provision under which the Companies may curtail QF energy output and discontinue purchases from QFs for such emergency periods; and

(6) Evolving the Commission's legally enforceable obligation policy to require a QF to make a more legally enforceable commitment to sell either through a revised Notice of Commitment Form or Commission-approved contracting procedures.

We believe that these changes are reasonable and necessary to ensure that our customers and our State's energy systems prosper as we continue to add renewable generation resources. DEC and DEP look forward to continued collaboration with interested parties to consider improvements which are critical to North Carolina's sustainable energy future.

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

A. Yes.

BY MR. SOMERS:

Q Mr. Yates, have you also prepared a summary of your direct testimony?

A Yes.

Q Would you please give that to the Commission at this time?

A Thank you.

(WHEREUPON, the summary of **LLOYD M. YATES** is copied into the record.)

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
Summary of Lloyd Yates' Direct Testimony
NCUC Docket No. E-100, Sub 148

The purpose of my testimony is to explain why Duke Energy believes that North Carolina is at a critical crossroads regarding the integration, development and customer costs of renewable generation under current PURPA policies. In this proceeding, Duke Energy Carolinas and Duke Energy Progress are advocating solutions that will transition North Carolina to a smarter, more sustainable approach for renewable generation.

Duke Energy and North Carolina are national leaders in renewable energy. Since 2007, Duke Energy has invested approximately $5.8 billion in renewable generation projects, including nearly $500 million by Duke Energy Carolinas and Duke Energy Progress. North Carolina policies have greatly encouraged solar development, mandating contract terms and setting avoided cost rates that are more generous than those in other states. Our state has seen unprecedented solar growth: we are second only to California in interconnected solar capacity and 60% of all installed PURPA projects in the United States are located in North Carolina. However, our recent experience demonstrates that a continuation of North Carolina's current policies will expose our customers to the significant burden of excess avoided cost rates. As detailed in the testimony of Companies' witness Glen Snider, DEC and DEP have long-term contracts with avoided cost rates ranging from $55 to $85 per MWh, while the Companies' current actual system incremental avoided costs are approximately $35 per MWh. The Companies and our customers are paying approximately $80 million more annually to solar developers than their actual avoided costs over the remaining life of the existing contracts, nearly $1 billion in total.

I explain that the unprecedented growth in variable, non-dispatchable utility-scale solar generation in recent years has also created planning and operational challenges for DEC and DEP. As Companies' witness Sam Holeman explains in more detail in his testimony, under existing policies, the Companies have no ability to dispatch and only limited emergency rights to curtail solar and other QF generators. This inhibits the Companies' ability to maximize the reliable and economic operation of the grid. DEC and DEP have gained experience over the past 18 months dealing with the operational impacts of surging utility-scale solar generation on their systems, and this proceeding represents the first opportunity in an avoided cost proceeding to inform the Commission regarding the detrimental impacts to the DEP system from the variable, non-dispatchable and non-curtailable utility-scale solar generation that has come online in predominantly 5 MW increments on rural distribution feeders in eastern North Carolina.

The policies that led North Carolina to this critical crossroads should be reevaluated to allow for a smarter, more sustainable and economic process. DEC and DEP propose a revised comprehensive approach which includes a competitive bidding process to ensure the orderly addition of cost-efficient new solar projects onto the Companies' systems. Companies' witness Kendal Bowman testifies to the details of the Companies' other proposed changes to the PURPA standard contract policies.

Duke Energy is proud to be a part of North Carolina's solar power success story. We believe that changes are necessary, however, to ensure the long-term viability and success of renewable generation in North Carolina and respectfully ask this Commission to approve our request. Thank you and this concludes my summary.

MR. SOMERS: Thank you, Mr. Yates. Mr. Chairman, Mr. Yates is available for cross examination.

CHAIRMAN FINLEY: Cross examination.

MR. CULLEY: Good morning. Thank you, Mr. Chairman. Thad Culley on behalf of Cypress Creek Renewables.

CROSS EXAMINATION

Q Good morning, Mr. Yates.

A Good morning.

Q It's a pleasure to get this started with you today. And so you were just summarizing your roles with Duke Energy Corporation and you mentioned leading the delivery of customer focus projects and services across the Company. Does that include all subsidiaries of Duke Energy?

A So when I talk -- let's be clear -- when I talk about the customer and delivery operations that includes all regular components of the utility.

Q Right. In this case, that would include Duke Energy Florida, Duke Energy Indiana, Duke Energy Ohio?

A That's correct.

Q And there are no others I'm missing there?

A That's correct.
Q Now, is there also within Duke Energy Corporation a commercial renewables unit?
A Yes, there is.
Q What companies make up the commercial renewables unit?
A So I don't know all of the companies off the top of my head. So there's a group called Duke Energy Renewables and there are a number of smaller subsidiaries under there.
Q Sure.
A I don't know the name of all of them.
Q That would be a Herculean feat I think. Thank you for that. And would you agree that all of the business segments operating under the Duke Energy umbrella are strategically aligned more or less when it comes to renewable policies?
A Are strategically aligned - so be more specific with that question, please?
Q Actually, let me move into the next question which I think will explain it better.
A Okay.
Q So in your direct testimony starting at page 5, line 13, and this is also actually included in

your summary, you state that quote, *Since 2007, Duke Energy has invested approximately $5.8 billion in renewable generation projects --*
A That's correct.
Q -- *including $300 million by DEP and $175 million by DEC in North Carolina.*
A Yes.
Q Thank you. So for DEC and DEP do you have any idea of what portion of that investment is in solar generation specifically?
A Of the --
Q Of the DEC and DEP investments that you note there just under $500 million?
A So most -- so, no, not specifically. Most of it is solar generation, yes.
Q Thank you. And are you aware of whether the other regulated subsidiaries have a similar level of investment to DEC or DEP or does DEC and DEP stand out?
A DEC or DEP have more solar investment than the other regulated components of the business on a percentage basis.
Q Thank you. And when DEC and DEP directly develop these projects, how are they financed? Do you

know that?
A They're financed by the -- typically at the utility level from -- at the utility.
Q So the utility is not engaged in borrowing money for any specific project or --
A That's correct.
Q -- raising equity investors for --
A That's correct.
Q And do the projects that are owned directly by the regulated utilities tend to be used to serve ratepayers, to serve retail load, that is?
A They do.
Q And would you say most or all of those projects are dedicated to that purpose?
A Typically all of those projects at DEC or DEP serve ratepayers.
Q Thank you for that. And if DEC and DEP account for only $475 million of the $5.8 billion, and North Carolina is the top solar for market, what is responsible for the bulk of the remaining $5.8 billion you cite?
A So some -- a lot of it goes to developers, QF facilities, qualified facilities.
Q And you would agree that $5.8 billion is

company-wide? Would that cover all business segments?
A Yes. So Duke Energy -- yes, so Duke Energy Renewables also develops solar outside of the regulated arm of Duke Energy, unregulated solar.
Q Thank you. And would you agree that Duke Energy Renewables is a market participant here in North Carolina?
A Yes.
Q And would you classify Duke Energy Renewables' participation here as minimal or something more than minimal?
A I would classify it -- well, something more than minimal.
Q And are the Duke Energy Renewables' projects that are developed or acquired in North Carolina, are they used to serve the retail load of the Company's ratepayers?
A So, no, they are serving other ratepayers typically in Dominion's service territory.
Q And would you agree that one of the aim of those projects is to generate a revenue stream to be profitable?
A Yes.

Q And are you generally aware of how Duke Energy Renewables finances or funds its projects?
A Yes.
Q And does that involve predominantly borrowing money from financial institutions on a project-specific basis?
A Typically they borrow money from the holding company.
Q Are you aware if any of the projects rely on any equity investors to be involved in those projects?
A So typically, no, they get money from the holding company, and the holding company does have equity, I mean, we have equity at the holding company level.
Q Sure. Would you agree that as a matter of course Duke Energy Renewables primarily invest in projects where the offtaker buys those -- buys the output under long-term Power Purchase Agreements?
A Yes.

MR. CULLEY: Great. And I think at this time I'd like to hand out a series of cross exhibits. I believe Charlotte -- Ms. Mitchell has already provided those, so thank you.

And at this time, Mr. Chairman, I'd like to introduce for identification an exhibit that's been premarked as Cypress Creek Renewables Cross Exhibit Number 1.

CHAIRMAN FINLEY: We'll mark it for identification as Cypress Creek Renewables Cross Examination Exhibit Number 1.

MR. CULLEY: Thank you.

Cypress Creek Renewables Cross Examination Exhibit 1
(Identified)

BY MR. CULLEY:

Q Do you have this exhibit in front of you, Mr. Yates?

A None of mine are marked so.

CHAIRMAN FINLEY: In the middle of the page there I believe --

MR. CULLEY: I think right there in the middle I have premarked as Cypress --

A Oh, I see it, okay.

BY MR. CULLEY:

Q To be more specific this is the Annual Report 2016 of Duke Energy.

A Uh-huh (yes).

Q Do you recognize this document?
A I do.
Q Do you agree that the Annual Report is posted on the Company's website?
A Yes.
Q And do you agree that you can find this report by clicking on the "Our Company" link and from there finding a sub page called "Investors"?
A I agree with that.
Q Thank you. And you would agree that investors are the intended audience for a document like this?
A Typically yes.
Q And is it within the scope of your duties to review and sign off on a 10-K filing and the associated Annual Report?
A Yes.
Q So you're familiar with the statements in this document?
A Yes.
Q If you would please turn to the next to the last page of the Annual Report, it's page 10. And if I could direct your attention to the right column, we're just going to look at the paragraph

that's second to the bottom, second to last paragraph on that page. So the sentence starts, quote, *Duke Energy Renewables, part of the Commercial Renewables business segment, includes utility-scale wind and solar generation assets which total 2,900 megawatts across 14 states from 21 wind and 63 solar projects. The power produced from renewable generation is primarily sold through long-term contracts to utilities, electric cooperatives, municipalities and commercial and industrial customers.* Did I read that faithfully?

A Yes, you did.

Q Thank you. Would it -- do you agree that the term "long-term" is a modifier before contracts in that sentence?

A Is a modifier?

Q Yes. So it gives meaning to the word "contracts" there.

A Yes.

Q So it would still be factually true to say that Duke Energy Renewables sells power through contracts to utilities?

A Yes.

Q Do you agree in the context of power purchases that long-term contracts have a connotation of stable, predictable revenue stream?

MR. SOMERS: Objection. Calls for speculation.

MR. CULLEY: Let me rephrase the question.

BY MR. CULLEY:

Q Mr. Yates, what connotation in your experience does long-term contracts have in this context?

A Long-term revenue streams.

Q Thank you. And are you aware that Duke Energy renewables has a website on the Duke Energy site that gives additional information about the commercial renewables unit or actually, specifically, Duke Energy Renewables and their solar and wind portfolios?

A No.

Q So you're not aware of that fact?

A I don't go onto their website. I don't spend my time at work on the website.

Q That's commendable, commendable. Well, are you aware then that an investor or a member of the public could do a simple Google search of Duke Energy Renewables and navigate to that page?

A Yes, I'm aware that you can navigate to the Duke Energy pages.

Q Right. So you're not aware that that page does include some information about those projects including their size, the offtaker, and in many instances the length of the contract?

MR. SOMERS: Objection, asked and answered.

CHAIRMAN FINLEY: Overruled. I think he's answered it already.

MR. CULLEY: Okay. Well, I think at this time it's appropriate to turn to the next cross exhibit that's marked Cypress Creek -- premarked Cypress Creek Cross Exhibit Number 2. And, Mr. Chairman, I'd ask that that be marked for identification?

CHAIRMAN FINLEY: It shall be so marked as Cypress Creek Renewables Cross Examination Exhibit Number 2.

Cypress Creek Renewables Cross Examination Exhibit Number 2

(Identified)

BY MR. CULLEY:

Q Mr. Yates, this exhibit includes a number of screen shots taken from the Duke Energy

Renewables website. And for ease of navigation here, I've marked this with very tiny - so maybe I shouldn't say ease of navigation - very, very tiny Bates numbering at the top right. So when I refer to that that's where I am directing you.

A Uh-huh.

Q Let's turn to Bates number 2, and here's a map titled "Duke Energy Renewables U.S. Portfolio". And do you see a legend at the lower left corner of the page?

A Yes.

Q And you see that solar power projects are represented by a yellow dot throughout this map?

A I see that.

Q And there is a break-out graphic, is there not, for the -- to accommodate the large number of North Carolina projects?

A Yes.

Q Thank you. Now, let's turn again to the next page, Bates 3, and do you see that this document is titled "Solar Power Projects"?

A Yes.

Q And does this appear to be a listing of solar projects that are owned by Duke Renewables Energy (sic) at least at some point and time?

A It does.

Q Okay. Well, let's skip a few pages here. If we can go to Bates number 7, let's look at a few projects. I'm sorry, not Bates 7. Actually -- my apologies, the small text. My eyes have already failed me. So do you see at this page --

MR. SOMERS: Which page are we talking about?

MR. CULLEY: So this is Bates number 7.

A So it is 7, okay.

BY MR. CULLEY:

Q And do you see this page to be a screenshot of a project called Murfreesboro Solar?

MR. SOMERS: Mr. Chairman, I've been very patient with this line of questioning about the unregulated affiliate that Mr. Yates is not here to testify on behalf of. I'm not sure of the relevance of going into a lot of detail about a project that the unregulated affiliate owns. He's already testified that he's familiar with the website so I would object to the relevance of this line of questioning.

CHAIRMAN FINLEY: Well, I think he's going to try to show something about the financing of these other projects so I'll overrule it for the moment.

MR. CULLEY: Thank you, Mr. Chairman.

BY MR. CULLEY:

Q Well, thank you, Mr. Yates. So if we read the description, it's in the lower right-hand corner of this page, and I would submit that all of these screenshots are going to have a description in that segment of the page. Do you see where it says, *Supplies electricity to North Carolina Electric Membership Corporation under the terms of a 20-year power purchase agreement*?

A I do.

Q And you would agree that a 20-year contract is indeed a long-term contract?

A Yes.

Q On the next page -- I'll tell you what, in the interest of time let's skip to page 10 which is Millfield Solar.

MR. SOMERS: Thad, if it will move things along, we're happy to stipulate that this exhibit represents what it says it does and it speaks for itself. We're not objecting to what the document says. If that will move things along, we're happy to do so.

MR. CULLEY: Okay. Mr. Chairman, I believe that would be acceptable. I think we can stipulate to that. I think it's a good time to pause and note that I do have an exhibit, which I've been informed by the Companies should be treated as confidential. And I know given the normal procedure of possibly getting through the Companies' witnesses and then getting to confidential material, that might be a challenge given Mr. Yates availability. So I wanted to ask the Companies if they have a recommended policy for or procedure for addressing that?

MR. SOMERS: So which exhibit is this? Is this 4?

MR. CULLEY: So I have not handed out the confidential exhibit at this point.

MR. SOMERS: Can we go off the record just one second?

CHAIRMAN FINLEY: Yes.

(OFF THE RECORD)

MR. CULLEY: Mr. Chairman, we've reached an agreement that the confidential exhibit I would wish to introduce they would stipulate in and I would not ask any questions about that at this time.

MR. SOMERS: And, again, just to be clear, Mr. Chairman, this is a confidential exhibit that we would ask be marked and treated as such in the record, Cypress Creek Renewables Cross Exhibit Number 3.

CHAIRMAN FINLEY: Cypress Creek has passed out what is labeled Cypress Creek Renewables Cross Examination Exhibit Number 3 and it is marked in red at the top, and each page is marked confidential. There are 14 pages. It shall be marked as such and treated as such in the record. And, Mr. Somers, you're agreeable that this is admissible into evidence?

MR. SOMERS: Yes, sir. We would stipulate to its admissibility.

CHAIRMAN FINLEY: In addition to this being marked, it shall be admitted into evidence.

Confidential Cypress Creek Renewables
Cross Examination Exhibit 3
(Identified and Admitted)

MR. CULLEY: Thank you, Mr. Chairman. In full disclosure to Mr. Somers, there was a summary compilation of the information prepared at the very back of the exhibit so I wanted to make sure you are aware of that. That just takes the rows and columns of North Carolina projects and puts them into one page but they still refer to the exact number of the rows so that you can verify that it is part of this spreadsheet.

MR. SOMERS: If I could just to be clear, you're saying that Bates number 14 --

MR. CULLEY: That's correct.

MR. SOMERS: -- on Cypress Exhibit Number 3 is a compilation that you prepared, not that Duke prepared?

MR. CULLEY: That is correct.

MR. SOMERS: Okay. No objection.

MR. CULLEY: Thank you. And thank you, Mr. Somers. I think we can move this quite along nicely here.

BY MR. CULLEY:

Q So just two more quick lines of questions for you, Mr. Yates.

A Okay.

Q I do appreciate your time this morning. On page 10, lines 14 through 20 --

A Of my testimony?

Q Yes, of your direct testimony. You state that quote, *As discussed in the Companies'* -- oh, I'm sorry, I'll give you a second to get there.

A I'm here.
Q Okay, great. That *As discussed in the Companies' Joint Initial Statement and by Witness Bowman, DEC and DEP are proposing a competitive bidding process;* is that correct?
A That is correct.
Q And are you aware of whether the Companies have made a specific proposal at this time?
A So in our filing with the Commission we have made a proposal for a competitive bidding process.
Q But no specifics about when, where or how --
A That's correct.
Q -- that would occur? Okay. And do the Companies still intend to provide more detail on that proposal?
A Yes, at some point.
Q But at this time you don't have an estimate of when that might occur?
A Yes.
Q And is that the case that the Companies have used the competitive bidding process as an alternative to the current regulatory regime under PURPA for QFs?
A As a --

Q As an alternative. I think as you said it might create for a smarter, more organized process.
A Yes, we believe the competitive bidding process allows us to bid for the capacity where needed as opposed to -- you think about the way the system works now, the incentive is to put 5-megawatt systems all on eastern -- in eastern North Carolina, but it doesn't necessarily match where the load is. The competitive bidding process allows us to have more control over where that capacity would go.
Q Thank you. And since there is no proposal presently before the Commission for approval, or the specific proposal, you would agree that from the solar industries' perspective that could be a long way off?
A I think we've asked the Commission to open a second separate docket to address the issue.

MR. CULLEY: I think I have no further questions. Thank you, Mr. Yates, for your time.

CHAIRMAN FINLEY: Cross?

MS. BOWEN: No.

MR. DODGE: No.

CHAIRMAN FINLEY: Anyone else?

(No response.)

CHAIRMAN FINLEY: Redirect?

MR. SOMERS: Thank you, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. SOMERS:

Q Mr. Yates, you were asked a question by Mr. Culley about the $5.8 billion investment that Duke Energy has made since 2007; do you recall that question?

A Yes.

Q And that $5.8 billion represents investment that Duke Energy in whichever business unit has made in renewable generation that it owns itself; is that correct?

A I think -- yes.

MR. SOMERS: Thank you. I have no further questions.

CHAIRMAN FINLEY: Questions by the Commission of Mr. Yates?

(No response.)

CHAIRMAN FINLEY: Mr. Yates, you may be excused.

(The witness is excused.)

CHAIRMAN FINLEY: And without objection we will introduce into evidence Cypress Creek Exhibits, Cross Examination Exhibits 1 and 2.

MR. SOMERS: No objection.

Cypress Creek Renewables Cross Examination
Exhibits 1 and 2
(Admitted)

MR. CULLEY: I'm sorry, Mr. Chairman, there was also the confidential exhibit 3.

CHAIRMAN FINLEY: That's already been admitted.

MR. CULLEY: That's already been moved. Thank you.

MR. BREITSCHWERDT: Mr. Chairman, at this time the Company calls John Samuel Holeman to the stand.

**JOHN SAMUEL HOLEMAN, III;** was duly sworn and testified as follows:

DIRECT EXAMINATION

BY MR. BREITSCHWERDT:

Q Good morning, Mr. Holeman.

A Good morning.

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

A Yes, sir. It's John Samuel Holeman, III, 526

South Church Street, Charlotte, North Carolina.

Q Thank you. And, Mr. Holeman, by whom are you employed and in what capacity?

A I'm employed by Duke Energy. I currently fill the role of Vice President of System Planning and Operations.

Q And did you cause to be prefiled in this docket on February 21st of this year 36 pages of direct testimony?

A Yes, sir.

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

A No, sir.

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

A Yes, sir.

MR. BREITSCHWERDT: Mr. Chairman, at this time I'd ask that Mr. Holeman's direct testimony be copied into the record as if given orally from the stand?

CHAIRMAN FINLEY: Mr. Holeman's direct prefiled testimony of February 21, 2017, of 36 pages is copied into the record as though given orally from the stand.

MR. BREITSCHWERDT: Thank you.

(WHEREUPON, the prefiled direct testimony of **JOHN SAMUEL HOLEMAN, III**, is copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

| | | |
|---|---|---|
| In the Matter of<br>Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016 | )<br>)<br>)<br>)<br>)<br>) | **DIRECT TESTIMONY OF JOHN SAMUEL HOLEMAN III ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC** |

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

A. My name is John Samuel Holeman III (Sam). My business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am employed as the Vice President of the System Planning and Operations Department for Duke Energy Corporation ("Duke Energy"). In that capacity, I oversee the planning and operations for Duke Energy's regulated electric utilities' electrical systems, including Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies").

**Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.**

A. I graduated from Clemson University in 1983 with a B.S. Degree in Electrical Engineering and in 1985 with a M.S. Degree in Electrical Engineering. I also obtained a Master of Business Administration Degree from Queens University in 2014. I am a registered Professional Engineer in North Carolina and South Carolina. I am also a member of the Institute of Electrical and Electronics Engineers.

**Q. PLEASE SUMMARIZE YOUR ENGINEERING AND TECHNICAL BACKGROUND AND EXPERIENCE.**

A. I joined Duke Energy in 1985 and have held various engineering and management positions in System Planning and Operations of increasing responsibility throughout my career. These positions include: EMS Application Engineer; System Operating Center Engineer; System Operator; Manager, System Operating Center; Director, System Operating Center; and

Director, Engineering and Training. In my current position, as Vice President – System Planning and Operations, I am responsible for compliance with the North American Electric Reliability Corporation ("NERC") and Federal Energy Regulatory Commission ("FERC") safety and reliability regulations, as well as planning and operations for Duke Energy's regulated electric jurisdictions.

I have also been extensively involved with and now manage the ongoing NERC and SERC Reliability Corporation ("SERC") system operations' compliance obligations for Duke Energy's regulated electric utilities. In this regard, I am recognized as a NERC Certified System Operator – Reliability. I served as Chair of the SERC Operating Committee from 2007 through 2009, and was also Chair of the NERC Operating Committee from 2009 through 2011. I also served as the NERC Event Analysis Subcommittee Chair from 2012 to 2014 and served on the NERC Essential Reliability Services Task Force from 2014 to 2015.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to inform the North Carolinas Utilities Commission ("Commission") of the Companies' growing experience with the operational concerns, reliability risks, and NERC compliance challenges associated with the rapid and ongoing deployment of qualifying facilities ("QFs") that are continuing to interconnect with and inject energy into the Companies' systems under the Public Utilities Regulatory Policy Act ("PURPA"). More specifically, my testimony explains how the continual surging growth in solar QFs is increasingly causing operational impacts, in particular operational excess energy currently occurring on the DEP system, and describes the Companies' responsibility to comply with NERC's Reliability Standards, specifically the "BAL" standards. I also explain how potential frequency deviations in violation of the BAL standards could cause an imminent system emergency on the Companies' systems, as well as in other electrical systems in the Eastern Interconnection.

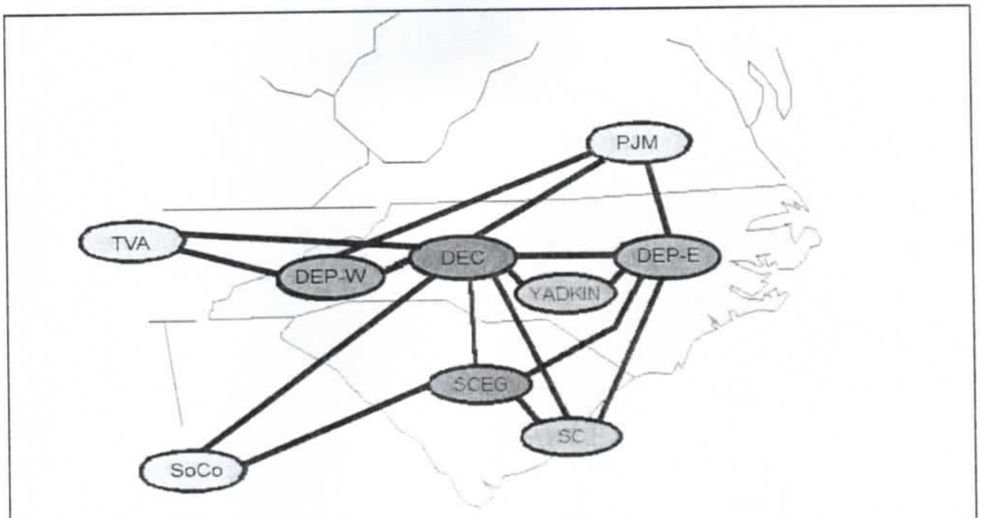
**Q. PLEASE EXPLAIN THE COMPANIES' ROLES AS NERC BALANCING AUTHORITIES FOR THEIR BALANCING AUTHORITY AREAS.**

A. DEP and DEC are each independent NERC Balancing Authorities ("BA") responsible for maintaining reliable operations on their systems, as well as managing power flows between their systems and other utility systems.[1] DEP and DEC must independently control their respective network resources to meet system loads, as well as maintain compliance with reliability regulations within their separate Balancing Authority Areas ("BAA"). This includes maintaining interchange schedules between the DEP BA and the DEC BA, as well as other neighboring BAs, such as the PJM Interconnection BA to the north, and the Tennessee Valley Authority BA to the west. Figure 1 shows the neighboring BAs, noting that each BA is responsible for independently

[1] The Balancing Authority is defined by NERC as "[t]he responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

complying with its mandatory NERC obligations, including providing its share of frequency support for the Eastern Interconnection.

**Figure 1**




DEC, DEP and Neighboring Balancing Authorities (BAs)

DEP and DEC are each subject to mandatory NERC regulations, requiring the Companies to independently balance their respective systems and to provide reliable firm native load service. Hence, each BA must independently maintain a Security Constrained Unit Commitment (discussed below) of base-load and load-following assets, regulation resources, operating reserves, and spinning reserves, working together to ensure real-time frequency support and balancing. These reliability requirements place the burden on the separate and independent DEP and DEC BAs to balance generation resources, unscheduled energy injections (from QFs), and load demand in real-time, which is essential to providing reliable firm native load service, maintaining compliance with

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mandatory reliability standards, and achieving reliable bulk electric system operations across the Eastern Interconnection.

**Q. PLEASE EXPLAIN HOW THE DEP AND DEC BAs CONFIGURE AND COMMIT THEIR LOAD FOLLOWING GENERATION ASSETS.**

A. DEP's and DEC's system operators must plan and operate the Companies' generating resources to reliably meet increasing and decreasing intra-day and day-ahead system loads within reliability and generating unit availability and operating limits. To meet this objective, DEP and DEC must independently plan for and maintain three general categories of reliability and load-following network resources. Each BA's operators select resources to reliably meet demand and provide firm native load service, referred to as the "Security Constrained Unit Commitment," consisting of the following:

(i) <u>Base-Load and Must-Run Regulation Resources</u>

(a) *<u>Base-Load Firm Native Load Resources</u>*. These are the generating resources (such as nuclear, coal, and large natural gas combined cycle units) that form the foundation of reliable service to meet the core system demand. They deliver the foundational inertial frequency to the system, and must operate within specified levels to provide stability against disturbances. *For reliability, these units cannot be de-committed in real-time nor on an intra-day basis.* As discussed below, as solar QF-caused operationally excess energy increases on the Companies' systems, these units cannot be de-committed at mid-day to accommodate the excess QF energy and then return to service for the evening or next morning peak demand.

(b) *Must-Run Regulation and Regulation Reserves Resources*. These are generating resources that must run to provide load balancing regulation (*e.g.*, balancing the BA Area Control Error ("ACE")) and frequency regulation support to maintain reliability by supporting system frequency to the required target of 60 Hz in compliance with mandatory NERC Reliability Standards. *For reliability, these units also cannot be de-committed in real time nor on an intra-day basis.* Similarly, in respects to the solar QF caused operationally excess energy, these generating resources cannot be de-committed at mid-day to accommodate the excess QF energy and then return to service for the evening or next morning peak demand.

(c) *Lowest Reliability Operating Level ("LROL")*. The base-load and must-run regulation units represent the foundational resources necessary to meet load requirements, provide reliability, and meet mandatory NERC Reliability Standards. In the aggregate, the operationally constrained minimum reliable output of these generators represents the LROL of the BA's Security Constrained Unit Commitment. *These essential generating resources cannot be de-committed in real time nor on an intra-day basis, because they must run within specified engineering levels and provide essential frequency and regulation support to the BA, and because they are needed to meet upcoming peak demands, such as the evening peak demands and next day peak demands.*

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(ii) Operating Reserves Resources

These are the load-following resources and reserves that provide for capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled outages, and local area protection. Generally, these units are available above the LROL output of the system's essential reliability generating resources. Traditionally, these resources were selected and maintained on a day-to-day basis and generally consist of fossil fuel quick-start and fast-start assets capable of providing energy to the system when the actual system load deviated from forecasted load. Now, however, these assets also operate in reverse in real time to adjust for solar energy injections into or withdrawals from the BA. In addition to the load-following service, the BA must also keep contingency generation assets online and in reserve to: (a) respond to forced outages and local area protection; (b) address load demand changes; and (c) now to manage unpredictable solar variability.

(iii) Spinning Reserves

These are fossil (coal and natural gas) and hydroelectric generation units that are online providing real-time spinning, regulation, and frequency reserves in response to real-time changes in customer load demand, and now increasingly responding to the intermittency of unscheduled solar energy injections into the system. These resources were installed to respond to the minute-by-minute variability in system load demand; however, they are now also responding to the intermittency of solar generation.

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**Q. PLEASE DESCRIBE THE CHALLENGES THE DEP AND DEC BAs ARE INCREASINGLY FACING BASED UPON YOUR RECENT EXPERIENCE INTEGRATING UTILITY-SCALE SOLAR INTO SYSTEM OPERATIONS.**

A. As described in the Companies' November 15, 2016, Joint Initial Statement ("Initial Statement"), this proceeding represents the Companies' first opportunity in a biennial avoided cost proceeding to inform the Commission of their growing experience managing the operational challenges of integrating significant additional QF solar on the DEP and DEC systems. The level of installed solar injecting energy into the DEP and DEC system has rapidly increased, particularly on the DEP system. The majority of this solar has been developed in DEP East, approaching 1,400 MWs of installed solar capacity interconnected and now injecting energy into the DEP system as of January 31, 2017. As the BA operator, DEP must balance the entire BA, and therefore, must balance for all solar installed capacity, whether interconnected directly to DEP in DEP's North Carolina or South Carolina region, whether interconnected with DEP's wholesale customers to whom DEP must also provide firm native load service, or whether interconnected as utility-scale solar or as a net-metering interconnection.

As noted in the Initial Statement and addressed by Company Witness Bowman, significant additional solar QF generation – upwards of 4,900 MWs – is proposing to interconnect and inject power to the Companies' systems, including approximately 3,800 additional MWs in DEP, in the next few years.

Based upon current solar QFs under construction and in development, the level of installed PURPA solar is projected to continue to grow rapidly in DEP and DEC over the next few years – increasing to over 2,800 MWs of installed solar capacity for DEP and to over 1,700 MWs of installed PURPA solar capacity for DEC by 2022.

Based on this continuing, rapid growth over the past 18 months and the associated operational experience in accordance with NERC's reliability requirements, the Companies have identified the following challenges associated with integrating these significant levels of PURPA solar: (i) managing "unscheduled" and "unconstrained" solar QF energy injections bounded by the Security Constrained Unit Commitment of reliable load-following service; (ii) managing the variability and intermittency of solar energy injections; (iii) managing the growing amounts of operationally excess energy injected by solar facilities, particular during the spring, fall, and winter periods; and (iv) ensuring compliance with NERC reliability standards, specifically including the BAL standards. The remainder of my testimony addresses each of these growing challenges.

**Q. PLEASE EXPLAIN WHAT THE COMPANIES MEAN BY "UNSCHEDULED" AND "UNCONSTRAINED" SOLAR QF ENERGY, AND WHY IT IS NOW IMPACTING THE RELIABILITY OF SYSTEM OPERATIONS.**

A. Solar QFs inject energy into the BA without any day-ahead or intra-day scheduling coordination with the system operator and without any





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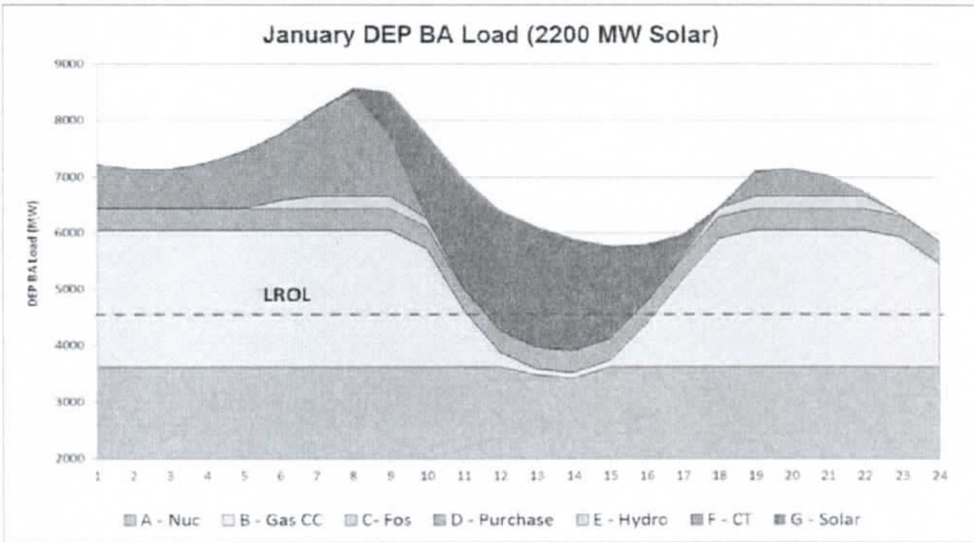
commitment to deliver scheduled quantities of energy into the BA, and therefore, are making "unscheduled" energy injections into the BA. Moreover, the unscheduled solar QF energy injections into the BAs are "unconstrained" by dispatch control due to PURPA's curtailment limitations. This is because under FERC's PURPA regulations, absent contractual agreement otherwise, a QF injecting energy into a system under a contract may be curtailed and the energy injections discontinued only in a "system emergency." The BA must be balanced in real time, and therefore, the BA system operator must instantaneously dispatch the output of its network resources in the opposite direction to respond to the increases or decreases in the solar QF energy injections. As shown in Figure 2 below, the real-time balancing of the system is becoming increasingly volatile due to large and uncertain swings in the unscheduled and unconstrained solar QF energy injections into the BA.

The Companies' recent and growing experience indicates that solar QF energy is injected into the BA whenever the sun shines, and therefore, the BA operator has limited tools to maintain reliability in the face of these unscheduled and unconstrained injections of QF energy. Because solar QF energy is both unscheduled for day-ahead and intra-day operational planning and is unconstrained for reliability dispatch control purposes, except for emergency conditions, BA resources must react to provide balancing and ancillary services such as regulation and frequency response. However, there are physical limitations to the BA's capability to reliably operate and absorb such unscheduled and unconstrained energy injections, as shown in Figure 2.

**Figure 2**




As noted and shown above, in planning to serve system load, the DEP system operator selects a Security Constrained Unit Commitment that is necessary to reliably provide firm native load service in the DEP BA and meet NERC reliability regulations. The Security Constrained Unit Commitment's LROL, below which the BA *cannot* reduce operational output, *must* be retained through the mid-day valley of the demand curve each day to provide for: (i) frequency regulation; (ii) resource availability to meet the evening peak demand, as well as; (iii) resource availability to meet the next morning's peak demand, which is generally higher than the previous evening's peak demand. The LROL is illustrated in Figure 2 by the dotted line and actual native load system demand is above the LROL – but the unscheduled and unconstrained solar QF injections into the BA take the "net" demand on system below the LROL causing operationally excess energy.

Currently, the DEP BA is continuing to experience rapid growth of unplanned solar QFs. These facilities maximize their output and continue to inject energy into the BA during the mid-day load valley when system demand is at its lowest. The BA cannot reduce its LROL level, causing system generation required for reliability to exceed the net system demand (actual load minus unscheduled/unconstrained solar QF energy), resulting in operationally excessive energy on the BA – *caused by operationally excessive solar QF installed capacity*. In the Figure 2 illustration above, the operationally excessive energy is all of the solar energy in the trough below the LROL.

The levels of unconstrained solar energy already being experienced during mid-day hours on certain non-summer days are forcing DEP to either: (i) increasingly ramp and cycle its intermediate and non-nuclear base load generators; and/or (ii) to sell the operationally excess solar QF energy into a neighboring BA using non-firm transmission, if available and if such transmission is not curtailed. Both of these options create potential real-time operating and reliability complexities and challenges. Looking ahead to 2017 and 2018, these challenges and risk will be amplified, particularly on the DEP BA as the quantity of solar QF installed capacity increases.

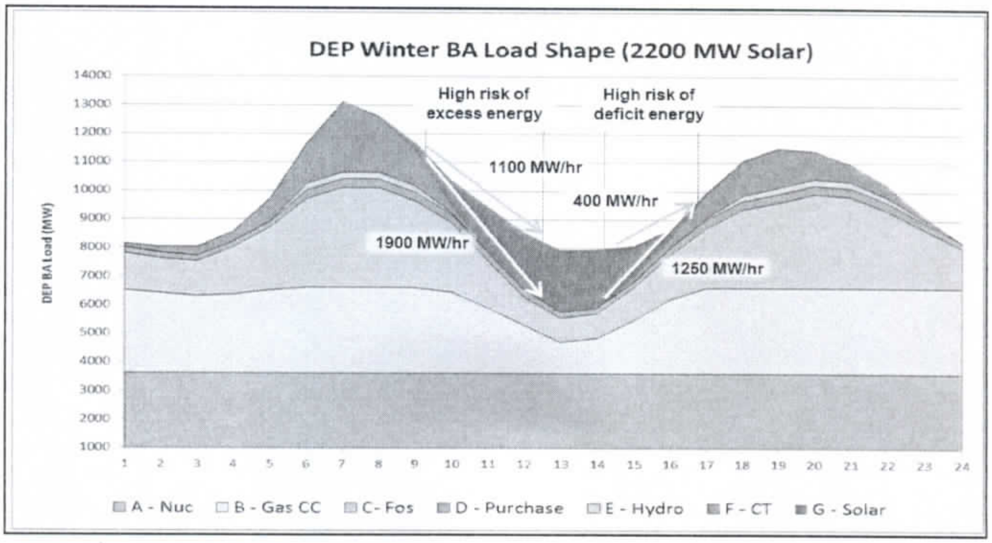
**Q. HOW CAN SOLAR FACILITIES BE BETTER INTEGRATED INTO THE COMPANIES' SYSTEM OPERATIONS?**

A. Unlike PURPA solar, the Companies own and operate utility-scale solar facilities as an operationally integrated resource. DEP's and DEC's facilities are built with automatic generation control equipment that provides DEP and DEC operators with real-time control over those facilities' output when necessary to balance BA load and resources. I want to be clear that I am not suggesting that DEP or DEC must own all of the solar resources. However, at high levels of solar QF penetration, it is critical that the BA system operator have operational control over generators so as to provide reliable electric service. Under the PURPA construct, the system operator does not have this essential control and is increasingly being challenged to manage the levels of solar QF energy being injected into the BA in real time.

**Q. PLEASE DESCRIBE HOW THE BA MAINTAINS REAL-TIME BALANCING OF DEMAND AND GENERATION AS VARIABLE QUANTITIES OF UNSCHEDULED AND UNCONSTRAINED SOLAR ENERGY IS INJECTED INTO AND WITHDRAWN FROM THE BA.**

A. Solar generators, by their nature, deliver variable quantities (i.e., low forecast certainty) of unscheduled and unconstrained energy into the BA during a narrow portion of the 24-hour load cycle, generally between 10 a.m. and 3 p.m. Solar generation is not online during the morning or evening system peaks during the fall, winter, and spring seasons. Therefore, solar QFs commonly inject their peak outputs of energy during mid-day hours when the sun is normally providing highest irradiance, but the real system load demand is at a lower mid-day level. In response to actual load demand, the BA reduces its network resources to the LROL, but not lower than that because the BA needs to have resources ready to ramp up to meet the evening load peak and the next morning's peak demand.

**Figure 3**




As Figure 3 shows, in the morning as the solar facilities begin to inject energy, the BA must rapidly start ramping down its resources that were online to serve the morning peak demands. This ramp down is accomplished by rapidly reducing network resource output in the opposite direction of the solar energy delivery curve. Correspondingly, in the afternoon, as system demand gains, the solar generation begins to fade and drop off. To balance the system in real time, the BA must rapidly ramp up the output of its fossil fuel





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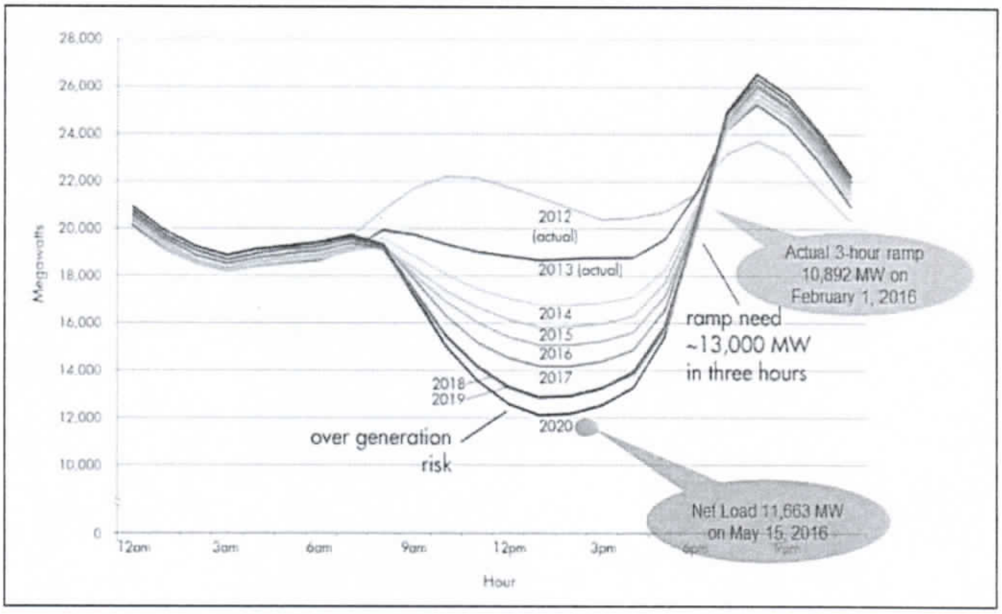
resources to catch the rapidly rising demand and support the evening peak load, while the solar generation is also rapidly dropping off.

For illustrative purposes, Figure 3 represents a winter day in the DEP BA with peak demand of more than 13,000 MWs and 2,200 MWs of solar installed capacity, which is what DEP is projecting by 2018 based on current penetration levels. It shows the morning peak served only by DEP's load following network resources, with very limited, if any, contribution to peak demand by the solar installed capacity. After the morning peak, the solar generation increases significantly, requiring steep down-ramps of DEP's fossil fuel resources, with increased risk of excess energy on the system if DEP is unable to take generation off-line fast enough as solar generation injections increase. Figure 3 shows that the majority of the solar generation is produced during the mid-day hours when the system has the least need for energy, and therefore, increases the risk of operationally excessive energy on the system. Lastly, it shows a rapid drop off in solar energy production in the afternoon hours, requiring steep ramping of network resources, and an increased risk of deficit energy on the system if DEP's fossil fuel resources are unable to keep pace with increasing demand and the rapidly fading solar generation.

**Q. HAVE OTHER BAs AROUND THE COUNTRY EXPERIENCED SIMILAR CHALLENGES, AS SOLAR ENERGY INJECTIONS INCREASE IN THE BA?**

A. Yes. Other BAs are experiencing similar reliability risks. The Commission may be familiar with California's "duck curve" problem, shown below.

**Figure 4**[2]




As seen in Figure 4, the adverse impacts on the California load shape projected to occur by 2020 have already occurred. Consequently, CAISO's system reliability is dependent on an Energy Imbalance Market ("EIM") and has to pursue a more flexible capacity portfolio to attempt to reliably accommodate the massive solar penetration in compliance with NERC Reliability Standards. Even with the EIM, CAISO is experiencing operationally excessive energy during mid-day hours and deficit energy issues during the steep ramping period of the evening peak demand. DEP's operational experience increasingly resembles the challenges of the California BAs with high levels of solar energy injections during non-peak hours of the day. Indeed, a recent October 2016 analysis by consulting firm Scott-Madden

[2] California Independent System Operator ("CAISO") Fact Sheet, accessible at http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

highlighted North Carolina as one of the "states to watch" where the duck curve would become more prominent due to growing levels of solar energy injections in excess of daily system needs.[3]

**Q. PLEASE EXPLAIN THE RELIABILITY RISKS CAUSED BY HIGH PENETRATION LEVELS OF VARIABLE AND INTERMITTENT RESOURCES INJECTING UNSCHEDULED AND UNCONSTRAINED ENERGY INTO THE BA, SUCH AS PURPA SOLAR QFs.**

A. There are a number of renewable generation technologies such as solar, wind, and geothermal, each of which have their own generating characteristics and periods of the day when they generate energy. A diversity of generating resources on a system creates a balanced portfolio with lower concentrations of operating characteristics and risks. High concentrations of a single type of resource, such as solar QFs, create imbalance in the portfolio and higher operating risks due to its generating characteristics.

For illustrative purposes, Figures 5 and 6 below show the output from the same set of solar generators (approximately 1,400 MWs capacity) injecting unscheduled and unconstrained energy into the DEP BA over two different seven-day periods during January 2017.

[3] *See* Revisiting the California Duck Curve, An Exploration of Its Existence, Impact, and Migration Potential, October 2016, Scott Madden Management Consultants at pp. 6-7. "North Carolina is already expecting solar to inject energy significantly in excess of system needs by 2020. Additional states to watch in the near term include: Arizona, Georgia, Nevada, and Texas. Each of these states, including North Carolina, are forecasted to have more than 3,000 MW of utility-scale solar by the end of 2021. The duck may also appear in less obvious environments, such as small balancing authorities with high penetrations of utility-scale solar.").

**Figure 5**

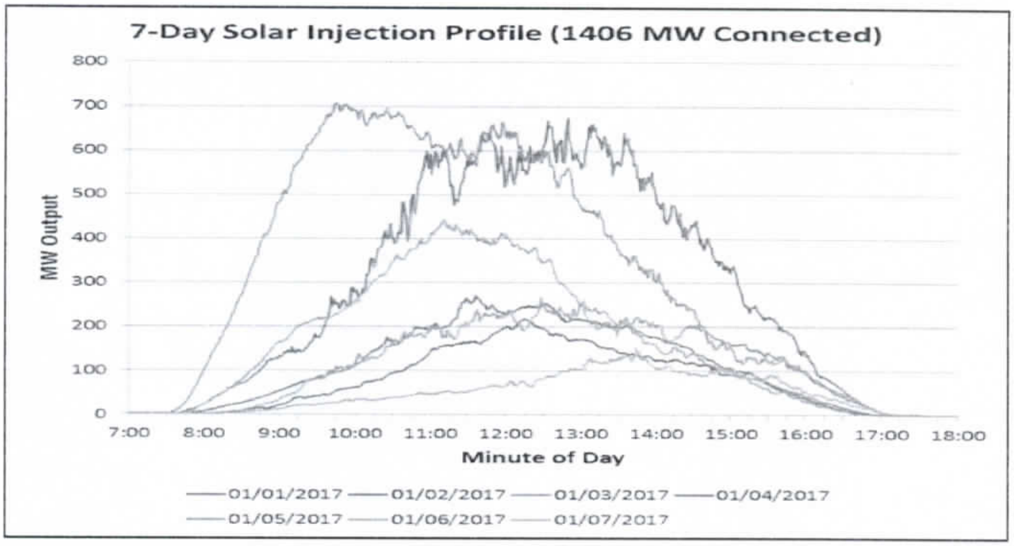
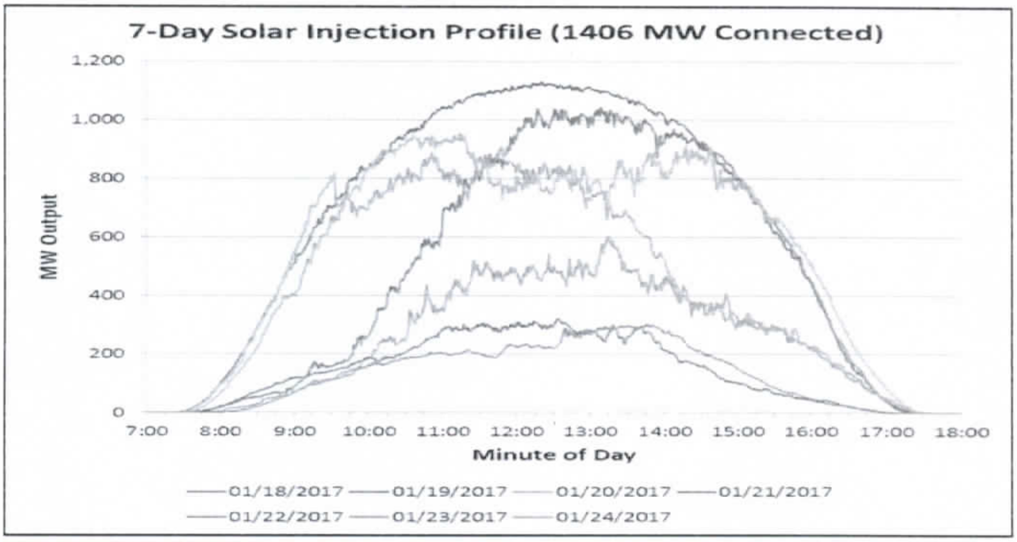



**Figure 6**




In Figure 5, the solar QF generators inject up to 700 MWs of output and as little as 150 MWs of output over that seven-day period, and in Figure 6, the solar QF generators inject up to 1,100 MWs of output and as little as 200 MWs of output over that seven-day period. These energy injections are, as noted above, unscheduled and unconstrained, and DEP must react to these injections in real time by operating its units in reverse to maintain real-time balancing in compliance NERC requirements. The "jagged" nature of the chart lines shows that the generation output has minute-by-minute volatility – which I refer to as "intermittency." The difference in production over the seven-day periods shows output variation from the same set of solar generators on a day-to-day basis and on an intra-day basis – which I refer to as "variability." As I will discuss below, it is important to appreciate the operational risks associated with the 1,100 MW to 150 MW output swings of these solar facilities, as they would impose very large energy swings on the BA. The charts also show that on some days the generators may follow a typical intra-day curve requiring an increasingly steep morning ramp-down and increasingly steep afternoon ramp-ups, or on other days have more volatile intra-day unscheduled injections requiring the BA's load-following assets to rapidly ramp-down in the early afternoon and then rapidly ramp-up within a few hours later in the afternoon.

Figures 7 and 8 below illustrate the magnitude of the forecast injection uncertainty on a day-to-day basis, as well as the intra-day energy injection volatility, when the same curves are scaled up to the projected 2,200 MWs by 2018 installed solar capacity on the DEP BA. In Figure 7, the solar QF generators inject up to 1,100 MWs of output and as little as 200 MWs of output over that projected seven-day period, and in Figure 8 the solar facilities inject up to 1,800 MWs of output and as little as 500 MWs of output over that projected seven-day period. These Figures illustrate the even more extreme energy swings that the DEP BA will soon begin to experience.

**Figure 7**

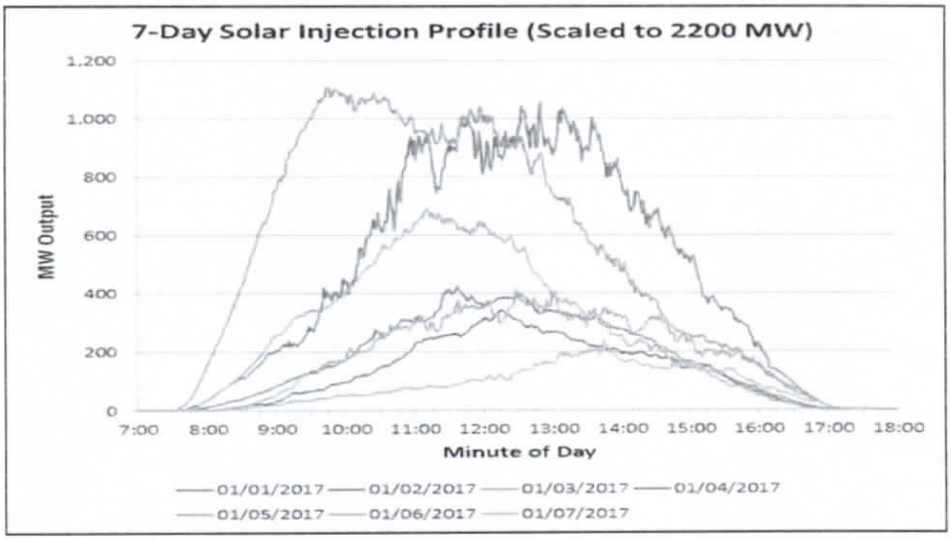
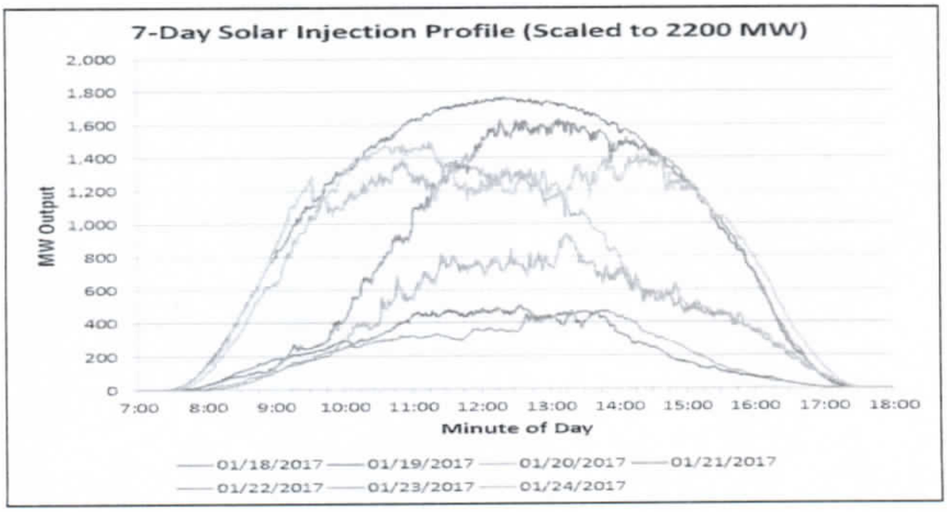



**Figure 8**




The forecasted data presented in Figures 7 and 8 demonstrate that solar capacity is operationally unreliable with significant day-ahead and energy production variability, volatility, and intermittency, because of their dependence on solar irradiance. These charts also demonstrate that as the unplanned solar capacity additions increase on the system, DEP has increasingly reduced and limited operational situational awareness over the performance of generators injecting increasing amounts of unscheduled energy into the BA. Accordingly, as DEP's operations become increasingly reactive and uncertain in nature, the reliability and operational impairments risks are also amplified.

**Q. ARE DEP OR DEC BEGINNING TO EXPERIENCE INJECTIONS OF SOLAR ENERGY INTO THEIR RESPECTIVE BAs IN EXCESS OF DEP OR DEC'S ABILITY TO RELIABLY ABSORB THE INJECTED ENERGY?**

A. Yes. DEP is now experiencing "operationally excess energy" with some regularity during an increasing number of days and hours throughout the year. Figure 9 below illustrates the operationally excessive energy being injected into the BA by the solar capacity installations that are in excess of the system's load demands and capability to absorb such energy injections, while also ensuring that the system is operating in a reliable manner to provide firm load-following service to customers. Figure 9 also identifies the very significant amounts of operationally excess energy with the 2,200 MWs of solar QF capacity projected by 2018 that results from maintaining the LROL minimum level of regulating resources required for system reliability online during the mid-day load valley, when the solar facilities will continue to inject energy into the BA.

**Figure 9**

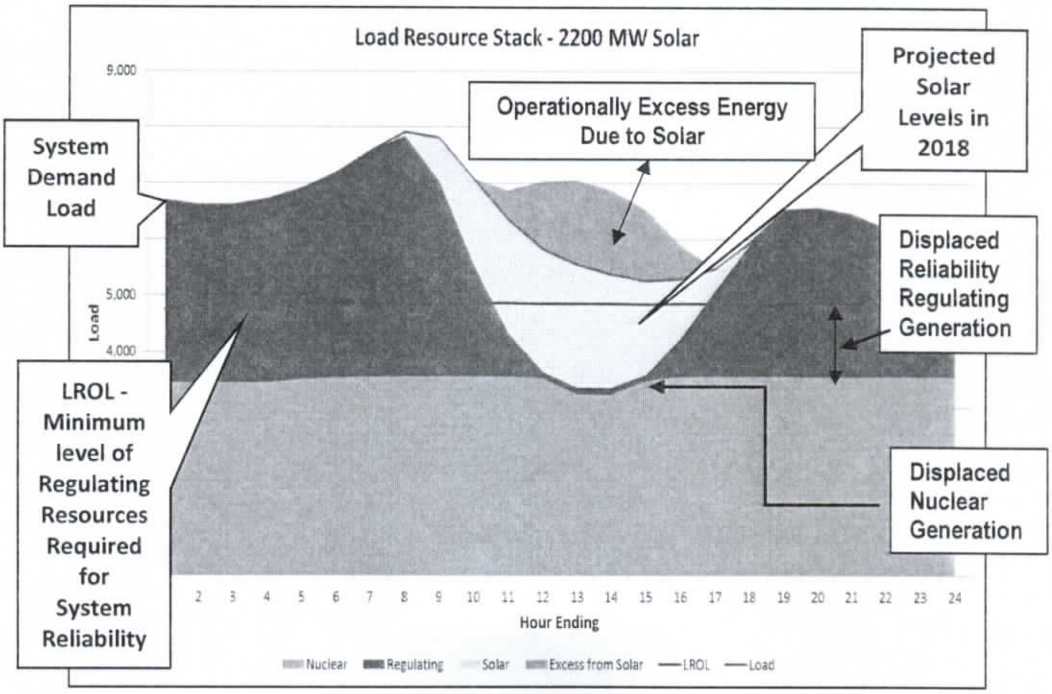
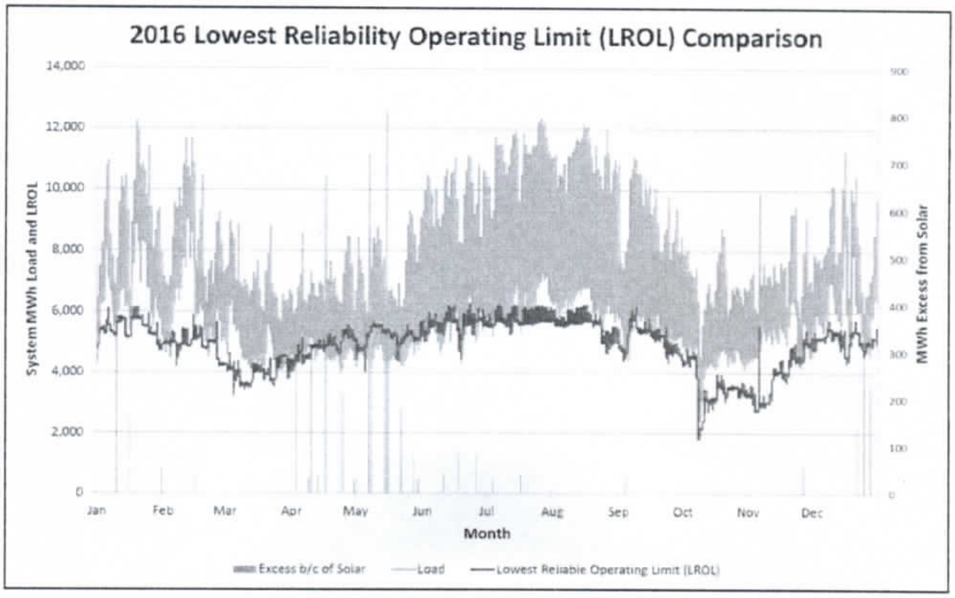



Figure 10 below illustrates the operationally excess energy that DEP experienced during 2016 due to solar QF installed capacity, showing the LROL resources at minimum output and with energy injections exceeding system demand during those periods. During calendar year 2016, there were 33 days and 105 hours when the DEP BA had operationally excess energy due to unscheduled and unconstrained solar QF injections. Already in 2017, there were 19 days and 71 hours when the DEP BA had operationally excess energy due to unscheduled and unconstrained solar QF injections.

**Figure 10**

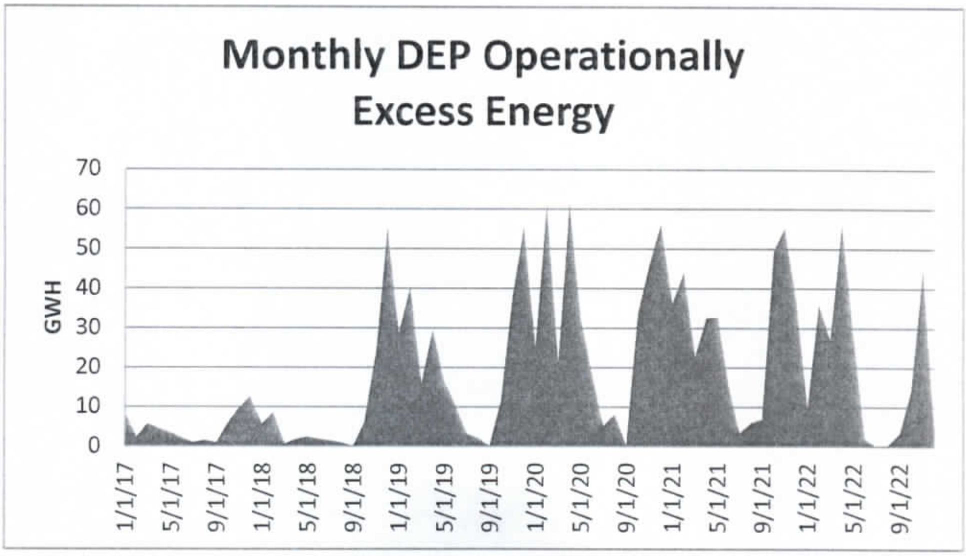



DEP's operational experience during 2016 demonstrates that due to physical limitations and reliability considerations, the Companies, who must manage their BAs to meet the LROL minimum reliability levels, cannot absorb unlimited quantities of energy from a single type of generating resource, particularly a generating resource such as solar QFs that inject unscheduled and unconstrained quantities of variable and intermittent energy during limited hours.

**Q. PLEASE PROVIDE A PROJECTION OF THE OPERATIONALLY EXCESS ENERGY ON THE DEP AND DEC BAs THAT WILL BE CAUSED BY CONTINUED DEPLOYMENT OF SOLAR QF INSTALLED CAPACITY.**

A. Using projections of QF solar facilities under construction and development, as well as QF solar facilities that will inject unscheduled and unconstrained energy into the DEP system at the current rate of development, Figure 11 forecasts the increasing amount of operationally excess energy on DEP's system from January 2017 through 2022.

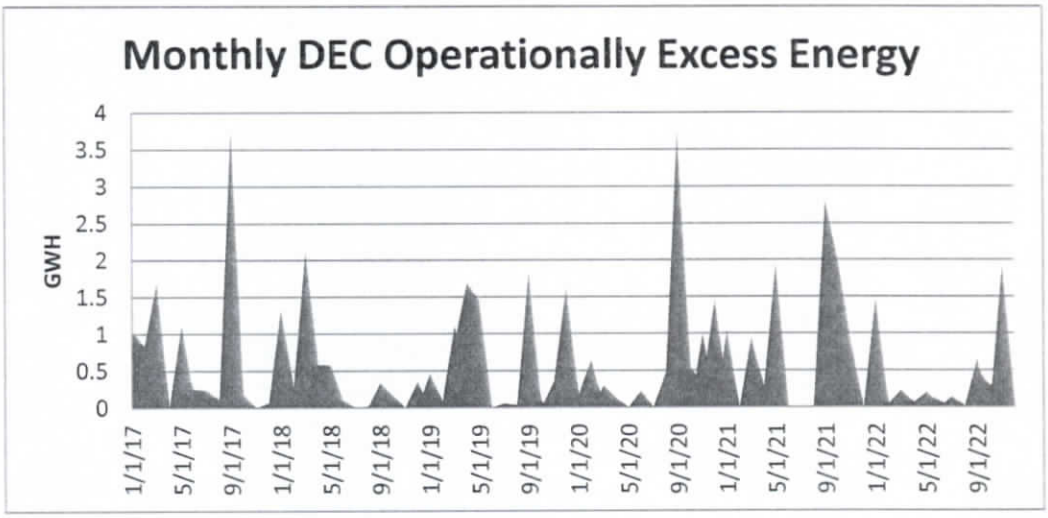
**Figure 11**




The operationally excess energy that DEP is projected to experience will approach *370 gigawatt hours per year*, concentrated between the hours of 10 a.m. and 3 p.m. Similarly, the DEC BA will also increasingly begin to experience operationally excess energy, as shown below in Figure 12.

Although the operational excess is not as severe as what will occur on the DEP system if change in policy is not implemented, the operational excess energy is present for each BA on both a stand-alone and aggregate basis.

**Figure 12**




**Q. WILL THE GROWING LEVELS OF UNSCHEDULED AND UNCONSTRAINED OPERATIONALLY EXCESS SOLAR QF ENERGY CHALLENGE FUTURE COMPLIANCE WITH NERC'S RELIABILITY STANDARDS?**

A. Yes. As introduced in the Companies' Initial Statement, maintaining compliance with mandatory NERC reliability standards is critically important and requires the BA to maintain proper generation reserves and to balance resources in real time. The growing levels and instances of operational excess generation associated with solar QFs, as described above, directly impact and challenge DEP's, and eventually DEC's, ability to plan for and assure compliance with NERC's reliability standards.

**Q. PLEASE EXPLAIN THE GENESIS OF THE NERC RELIABILITY STANDARDS.**

A. On August 14, 2003, the largest blackout to-date occurred in the Northeastern and Midwestern United States and the Ontario province of Canada. In response to the 2003 blackout, the United States and Canadian authorities created a task force to perform a root cause analysis of the blackout events, concluding, in part, that mandatory and enforceable reliability standards were needed to protect against similar catastrophic bulk power system events in the future. Accordingly, Congress included in the Energy Policy Act of 2005 ("EPACT 2005") provisions for an independent Electric Reliability Organization ("ERO") reporting to FERC. Under the authority granted by EPACT 2005, under Section 215(c) of the Federal Power Act, FERC designated NERC as the ERO with a mandate to develop and enforce reliability standards.

NERC develops, enforces, and improves mandatory reliability standards for seven Regional Reliability Organizations ("RRO"), including our regional organization, SERC. NERC (through the RROs) determines if an entity is complying with its reliability requirements, and FERC takes action for non-compliance with NERC's mandates, including levying civil penalties. In 2007, FERC approved the first set of NERC's mandatory Reliability Standards, which have been expanded and refined over time to ensure interconnected "Bulk Power System" reliability is maintained across North America. Over the past decade, NERC has established over 100 mandatory reliability standards to regulate operation of the Bulk Power System, including the operations of BAs, such as DEP's and DEC's BAs.

**Q. PLEASE DESCRIBE DEC'S AND DEP'S NERC RESPONSIBILITIES.**

A. In addition to its operations as a BA, DEC and DEP perform various additional NERC reliability functions. As a generator owner and generator operator, DEC and DEP own, maintain, and operate generating units to supply reliable and affordable electricity to approximately 4 million customers in North Carolina and South Carolina. As a transmission owner and transmission operator, DEC and DEP own, maintain, and operate transmission facilities in North Carolina and South Carolina, and are responsible for operating the transmission system in a reliable manner in compliance with applicable NERC reliability standards. In my role as Vice President for System Planning and Operations, I am directly responsible for ensuring the Companies' ongoing compliance with the NERC reliability standards.

**Q. PLEASE EXPLAIN THE IMPORTANCE OF NERC'S BAL STANDARDS AS THEY APPLY TO SYSTEM RELIABILITY.**

A. DEC and DEP must comply with all applicable NERC reliability standards and associated requirements, including the BAL standards. Together, the BAL-001, BAL-002, and BAL-003 standards are designed to enhance the reliability of each Interconnection by maintaining frequency within predefined limits every 30 minutes under all conditions, and effectively mandate every

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Feb 21 2017

BA to balance generation resources to load demand within the BA during each 30-minute reporting period. The purpose of BAL-001 is to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply resources in real time and, as needed, to take action to support reliability.[4] These standards, of which BAL-001-2 was updated effective July 1, 2016, demonstrate NERC's focus on the importance of properly regulating frequency within each BA, providing proper reserves for balancing generation and demand in real time, providing reserves for primary frequency response, and providing reserves for restoring resource-to-demand balance within 15 minutes following a sudden loss of a designated load following generating unit or disturbance event on the BA and on the Eastern Interconnection generally.

The BAL standards are important reliability standards, because they regulate a BA's performance with respect to maintaining proper reserves to balance resources and demand in real time and provide for proper frequency regulation within its operating boundary, so as to control a BA's impact on the reliability of neighboring BAs across the interchange tie lines and the regional Interconnection generally. Importantly, a BA's failure to comply with reliability standards could result in system emergencies and reliability failures,

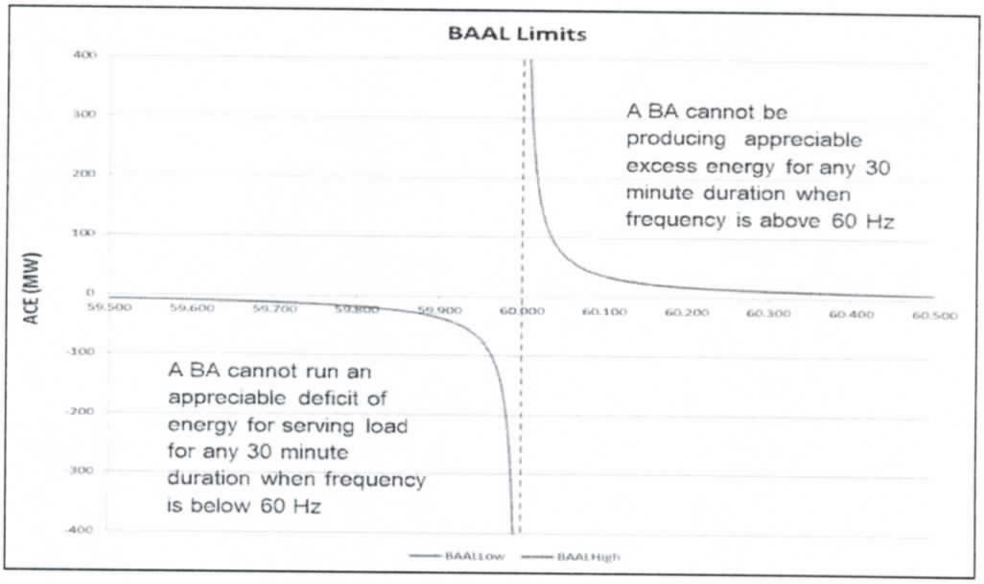
[4] There are two requirements associated with BAL-001. The current version of the BAL-001 standard, BAL-001-2 became effective on July 1, 2016, and requires each BA to operate such that its clock-minute average of Reporting Area Control Error does not exceed its clock-minute Balancing Authority ACE Limit [BAAL] for more than 30 consecutive minutes for the applicable Interconnection in which the BA operates. Source: NERC Reliability Standard BAL-001-2, Real Power Balancing Control Performance, Enforcement Date: 7/1/2016. Available at: http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx (United States, BAL-001-2).

such as unscheduled power flows, unnecessary and automatic firm load shedding, or in a worst-case scenario, cascading outages across the Interconnection.

**Q. PLEASE EXPLAIN HOW A BA WITH OPERATIONALLY EXCESS ENERGY FROM SOLAR QFs IS INCREASINGLY AT RISK OF VIOLATING THE BAL STANDARDS, RESULTING IN A SYSTEM EMERGENCY.**

A. Figure 13 shown below depicts a BA's requirement under NERC to maintain its frequency within normal limits on a consecutive 30-minute basis. If a BA experienced too much energy relative to real-time load in the BA, causing frequency to rise above the scheduled frequency (60 Hz), the BA would be operating in the upper right quadrant of the Figure 12 graph. Conditions for this circumstance are currently occurring on the DEP BA as solar QF capacity in excess of DEP's physical limitations to absorb energy continues to inject unscheduled and unconstrained energy into the BA. DEP can ramp down its load following generating resources to the lowest reliability operating level of its Security Constrained Unit Commitment; however, during the mid-day lowest demand period, DEP cannot further reduce its dispatchable resources, and the solar QF energy causes excessive energy on the DEP BA. If DEP were unable to mitigate the excess energy, its system would be in the upper right quadrant, with compromised reliability.

**Figure 13**




Similarly, if a BA experienced deficit in energy relative to real-time demand in the BA, causing frequency to drop below the scheduled frequency (60 Hz), the BA would be operating in the lower left quadrant of the Figure 13 graph. Conditions for this circumstance are also currently occurring on the DEP BA as solar QF capacity continues to inject unscheduled and unconstrained energy into the BA in excess of physical limitations to absorb the energy. However, if a change in weather or other event suddenly caused large volumes of solar QF energy to drop off the system, or in the late afternoon period as the solar energy drops off, and DEP was unable to ramp up its load-following generating resources fast enough, or if DEP were to lose a sizable network generating resource, then there would be a deficit of energy on the DEP system. Under such conditions, DEP's system would be in the lower left quadrant, operating with compromised reliability.

If the BA were to operate in either of these above-described conditions for more than 30 consecutive minutes, the BA would be in violation of the BAL-001 Standard. Compliance with the NERC BAL-001 standard is mandatory because it recognizes that operating a BA in either of these non-compliant over-frequency or under-frequency regions for even 30 minutes places the Eastern Interconnection at risk of creating the following reliability impacts: (i) over-speed risks for generators when operating in an excess energy mode; or (ii) creating the risk of unplanned firm load shedding via under-frequency load shedding relay actuation if operating in a deficit energy mode.

**Q. PLEASE EXPLAIN HOW OPERATIONALLY EXCESS ENERGY ALSO CHALLENGES COMPLIANCE WITH BAL-002 AND BAL-003 STANDARDS.**

A. The BAL-002 Standard requires a BA to provide contingency reserves within 15 minutes of the loss of a designated network generating resource to restore the resource-to-demand balance that existed just before the loss of the resource. Variable and intermittent resources, such as solar generators, with dynamically changing output levels in an unscheduled or uncontrolled manner during the 15-minute recovery period contribute to the occurrence of a BAL-002 violation. The reliability risks associated with the BAL-002 requirement to recover to pre-disturbance resource-to-demand balance levels within 15 minutes is similar to the BAL-001-2 Standard, in that resource-to-demand imbalance leads to frequency excursions on the Eastern Interconnection and unscheduled power flows between the BA experiencing the loss of resource and its neighboring BAs. With the variability and intermittency of unscheduled solar generation, the solar output can significantly decline at the critical time that the BA is trying to recover from a loss of a base load generator, such as a nuclear resource.

The BAL-003 standard defines the amount of frequency response needed from BAs to maintain Interconnection frequency within defined bounds, and includes requirements for the measurement and provision of frequency response. The BAL-003 standard establishes a minimum frequency response obligation for each BA, provides a uniform calculation of frequency response, establishes frequency bias settings that set values closer to actual BA frequency response, and encourages coordinated automatic generation control operation. By this standard, NERC requires BAs to provide primary frequency response to mitigate susceptibility to under-frequency load shedding actuation that sheds firm load.

As noted in the BAL-001-02 discussion, large amounts of solar QFs on a system, such as with DEP, increase the risk of deficit energy conditions relative to load demands, which are a leading cause of low frequency disturbances on a BA.

**Q. IN THE CONTEXT OF THESE BAL REQUIREMENTS, PLEASE EXPLAIN HOW AN ADVERSE RELIABILITY EVENT COULD OCCUR ON A BA, SUCH AS DEP, THAT IS OPERATING WITH HIGH LEVELS OF SOLAR QFs INJECTING UNSCHEDULED AND UNCONSTRAINED ENERGY INTO A BA.**

A. By 2018, the DEP system is projected to have 2,200 MWs of solar generation injecting unscheduled and unconstrained energy into the BA. Other than Company-owned solar facilities over which DEP has full control, DEP's system operators currently have no dispatch control and no day-ahead planning control over the variable energy injections into the BA from solar QF generators. Increasingly, DEP will be required to manage reliability in a reactive operational mode, with very limited forecast situational awareness of the variable and intermittent energy injections into the BA.

To isolate risks for this example, put aside the intermittency and variability of the solar QF injections that intensify the overall operational challenge of balancing the system in real time. As the energy output of the solar QFs begins to fade in the late afternoon hours as the sun's irradiation reduces, DEP will be reacting to those reductions by ramping up its fossil-based load following network resources. The concern and risk to the Eastern Interconnection is that if a disturbance originating on another BA cascades to the DEP BA across the interchange, or if DEP were to experience an equipment failure causing a load-following network resource to trip off-line, or if the DEP BA were to experience a sudden deficit of energy from solar facilities, then the DEP BA would have a significant deficit energy condition on its system. This deficit energy condition would then trigger a frequency decline, which could then result in under-frequency load shedding ("UFLS") relay set points activating, causing the system to shed firm load in an unplanned manner, potentially putting public health and safety at risk across the DEP system. Other neighboring BAs, also with high and growing levels of solar QF penetrations, such as the DEC BA, could then in turn be challenged to maintain reliable operations on their systems, where a similar sequence of deficit energy, low frequency, UFLS activation, and firm load shedding could potentially occur.

**Q. HAS THE COMPANY PROPOSED A CHANGE TO ITS STANDARD TERMS AND CONDITIONS TO PROVIDE IMPROVED OPERATIONAL CONTROL DURING POTENTIALLY IMMINENT SYSTEM EMERGENCIES WHERE THE BAL STANDARDS ARE AT RISK OF BEING VIOLATED?**

A. Yes. Company Witness Kendal C. Bowman supports the proposed revision to the Companies' standard offer terms and conditions. For the reasons described above, strict compliance with these stringent and mandatory BAL standards is necessary for reliability across the BA and the Eastern Interconnection, because failure to maintain compliance with these standards could cause an imminent risk of system emergencies. These excess and deficit energy reliability impairments are directly correlated with the significant amounts of unscheduled solar generation being injected into the

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BA, without the BA operator having operational control over the facilities. The ability to curtail solar QFs, as provided in the amended terms and conditions will provide some measure of improved operational control during a potentially imminent system emergency situation.

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

A. Yes, it does.

BY MR. BREITSCHWERDT:

Q Mr. Holeman, did you also cause to be prefiled in this docket on April 10, 22 pages of rebuttal testimony?

A Yes, sir.

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

A No, sir.

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

A Yes, sir.

MR. BREITSCHWERDT: Mr. Chairman, at this time I would ask that Mr. Holeman's rebuttal testimony be copied into the record as if given orally from the stand?

CHAIRMAN FINLEY: Mr. Holeman's rebuttal testimony of April 10, 2017, consisting of 22 pages is copied into the record as though given orally from the stand.

(WHEREUPON, the prefiled rebuttal testimony of **JOHN SAMUEL HOLEMAN, III**, is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

| | | |
|---|---|---|
| In the Matter of | ) | |
| Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016 | ) | **REBUTTAL TESTIMONY OF JOHN SAMUEL HOLEMAN III ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC** |

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

A. My name is John Samuel Holeman III. My business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am employed as the Vice President of the System Planning and Operations Department for Duke Energy Corporation ("Duke Energy"). In that capacity, I oversee the planning and operations for Duke Energy's regulated electric utilities' electrical systems, including Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies").

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

A. Yes. I pre-filed direct testimony on behalf of the Companies on February 21, 2017, in this proceeding.

**Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A. My rebuttal testimony responds to Public Staff Witness Dustin R. Metz's testimony and recommendations concerning system operations, safety, reliability, and regulatory compliance in regards to the current, upcoming, and future North American Electric Reliability Corporation ("NERC") Reliability Standards. As recommended by Witness Metz, my rebuttal testimony seeks to further inform the Commission of the adverse impacts to reliable operations, risks of NERC non-compliance, and diminished operational flexibility and situational awareness, especially on the DEP system, because of the very high levels of energy being intermittently injected into and withdrawn from the system by solar qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act ("PURPA").

In connection with the safety and reliability risks addressed by the more robust BAL-002 standard, to be effective January 1, 2018, my rebuttal testimony responds to Public Staff Witness Metz's discussion of the Joint Dispatch Agreement ("JDA")[1] between DEC and DEP. Specifically, I explain the inherent limitations of the purely economic role of the JDA and the non-firm, curtailable transmission path between DEC and DEP underlying the JDA's economic transfer capability.

I also respond to Public Staff Witness Metz's discussion about potential future "system emergency" curtailments of QFs on the DEP system, and explain the high likelihood of operational curtailments of QFs that will be required in real time to ensure compliance with NERC's Reliability Standard requirements and avoid real risks to reliable electric service, principally as additional QFs continue to come online.

Finally, I rebut North Carolina Sustainable Energy Association ("NCSEA") Witness Ben Johnson's dismissive statement that the Companies' system operations experience and the future safety, reliability, and regulatory compliance challenges demonstrated in my direct testimony are merely "growing pains."[2] Every electric system has physical limitations as to the

[1] Joint Dispatch Agreement, effective July 2, 2012, between Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (formerly known as Carolina Power & Light Company) on file with the Federal Energy Regulatory Commission ("FERC") in Docket No. ER12-1338-000.

[2] NCSEA Johnson Testimony, at 209.

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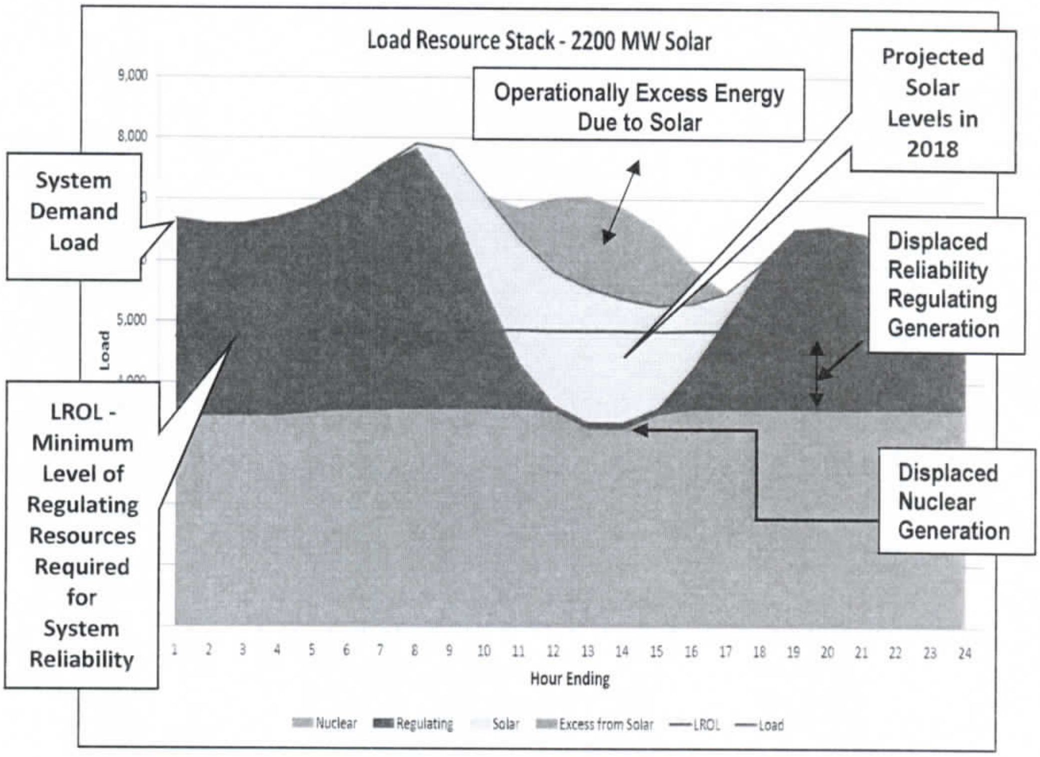
amount of any resource that it can safely and reliably accommodate. As a system operator, I am agnostic as to the type of generation technology connected to the system, as long as I can prudently provide reliable and secure service to our customers.

**Q. PLEASE BRIEFLY SUMMARIZE YOUR DIRECT TESTIMONY.**

A. My direct testimony informed the Commission of the impacts to system reliability and risks of non-compliance with NERC's Reliability Standards due to the operationally excess energy that is being injected into the DEP balancing authority ("BA"). I explained that QFs inject energy into the BA without any commitment, and without day-ahead or intra-day coordination with the BA, and therefore, are making "unscheduled" energy injections into the BA. These unscheduled QF energy injections are "unconstrained" by dispatch control due to PURPA's limitations, except under contractual provisions for "system emergency" conditions. I also demonstrated how the real-time balancing of the DEP BA has become volatile due to large and uncertain swings of unscheduled, intermittent solar QF energy injections into the BA.

I explained that the BA operator must select a Security Constrained Unit Commitment that is necessary to reliably provide firm native load service in the DEP BA and meet NERC Reliability Standards. As explained in my direct testimony, the Security Constrained Unit Commitment's Lowest Reliability Operating Level ("LROL"), *below which the BA cannot reduce operational output*, must be retained through the mid-day valley of the demand curve each day to provide for: (i) frequency regulation; (ii) resource availability to meet the evening peak demand; as well as (iii) resource availability to meet the next morning's peak demand, which is generally higher than the previous evening's peak demand for winter load patterns. The "LROL" is illustrated in Figure 1 by the red line (which replicates Figure 9 from my direct testimony).

**Figure 1**




I explained that the DEP BA is currently experiencing operationally excess energy during certain hours caused by the very high levels of QF capacity additions. As illustrated above, during these QF-caused over-generation events, although the BA's actual load demand is above the LROL (i.e. no system over-generation), the unscheduled and unconstrained QF energy injections are causing "net" demand to drop below the LROL. This causes operationally excess QF energy due to the operationally excess QF capacity additions. As additional QFs request to interconnect and inject energy into the system under PURPA, the DEP BA is increasingly exposed to significant risks to reliable electric service.

**Q. WHAT WILL BE THE SOLAR QF PENETRATION LEVELS ON THE DEP BA BY EARLY 2018?**

A. As of the time of my rebuttal testimony, approximately 1,552 MWs of solar QFs are interconnected and injecting energy into the DEP BA, including North Carolina, South Carolina, and behind-the-meter wholesale interconnections. There are approximately 831 MWs of additional solar QFs already under construction that are expected to become operational by early 2018. This means that solar QF penetration in the DEP BA will soon be at or greater than 2,200 MWs – *functionally, making these intermittent facilities the largest aggregate generator on the DEP BA.*

**Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS METZ'S CONCLUSION THAT A VIOLATION OF MANDATORY RELIABILITY STANDARDS, SUCH AS THE BAL-001, 002, AND 003 STANDARDS OVER THE PERFORMANCE MEASUREMENT PERIOD (15-30 MINUTES), COULD "DAMAGE GENERATORS, LEAD TO LOAD SHEDDING, AND, IN THE WORSE CASE SCENARIO, COLLAPSE THE SYSTEM ACROSS THE ENTIRE**

**EASTERN INTERCONNECTION, NOT JUST WITHIN DEC'S OR DEP'S BALANCING AUTHORITY AREAS"?** [3]

A. Yes, I do. Public Staff Witness Metz correctly recognizes that compliance with NERC Reliability Standards, specifically including the BAL-001, 002, and 003 standards discussed in my direct testimony is mandatory, *because compliance with these standards is essential to ensuring reliability*, not only in the DEP and DEC BAs but across the entire Interconnection.

Public Staff Witness Metz also is correct that "[c]ontinued growth in unconstrained and non-dispatchable generation will only serve to exacerbate the current system challenges."[4] I am especially concerned about the adverse impact the excessive quantities of QF energy injections into and withdrawal from the DEP BA is having on DEP's capability to meet its obligation to provide essential reliability services.

As I discuss below, Public Staff Witness Metz is correct in noting that NERC is continually reviewing and revising its Reliability Standards to address evolving reliability concerns. These revised standards usually require the BA to plan for and meet more robust operating practices. For example, the BAL 002-2 standard that will be subject to enforcement starting January 1, 2018, will apply more rigorous operating contingencies and will expand the risk of violating the BAL 002 standard on both the DEP and DEC BAs.

[3] Public Staff Metz Testimony, at 4-5.

[4] Public Staff Metz Testimony, at 9.

**Q. WHAT ARE ESSENTIAL RELIABILITY SERVICES?**

A. Essential reliability services are elemental reliability building blocks integral to providing reliable electric service to customers and protecting system equipment, and must be provided regardless of the BA's resource mix. Observing the potential for variable energy resources to impact necessary reliability services delivered by large rotating mass synchronous generators essential for reliable electric system operations, NERC established the Essential Reliability Services Task Force in June 2014, to examine these essential reliability services and develop standards for their application.

As noted above, essential reliability services are provided by designated network and contingency resources that have synchronous, load-following response capabilities. The components of essential reliability services are: (i) voltage support; (ii) system inertia; (iii) ramping; and (iv) frequency support. In connection with my discussion of the BAL-001, 002, and 003 standards in my direct testimony, I discussed impacts to ramping and frequency support due to the very high levels of QF energy injections. Essential reliability services are critical to reliable BA operations, therefore, they are measured and monitored to comply with NERC requirements so that operators and planners are aware of the changing characteristics of the BA and can make informed decisions to operate the BA in a reliable manner.

In response to Public Staff Witness Metz's recommendation that I explain the impacts of the upcoming BAL-002-2 standard, I will briefly elaborate on the impacted essential reliability services.

**Q. ARE THE HIGH LEVELS OF PURPA FACILITIES, ESPECIALLY SOLAR QFs IN THE DEP BA, CHALLENGING DEP'S CAPABILITY TO PROVIDE ESSENTIAL RELIABILITY SERVICES?**

A. Yes they are. The DEP BA is currently operating with reduced operational flexibility and diminished situational awareness under normal conditions. Operational flexibility and situational awareness will further diminish as more QFs become operational and inject even more unscheduled and unconstrained energy into the BA. In addition to being variable, intermittent, unconstrained, and unscheduled in nature, solar QF energy injections into the BA are also "non-conforming to load," meaning that solar energy injections do not support the BA's peak demands for most of the year, neither for the morning peak nor for the late day peak for fall, winter, and spring load shapes.

Operating with diminished flexibility during normal conditions places the BA under even greater risks of NERC violations and greater risks to reliable electric service during abnormal conditions. At current levels of solar QF energy injections, DEP is already experiencing "exceedances" of NERC's Balancing Authority ACE Limit ("BAAL"), as I describe later in my rebuttal testimony. As operating conditions become more rigorous under new standards going forward, such as under the new BAL-002-2 standard, non-compliance risks will also increase.

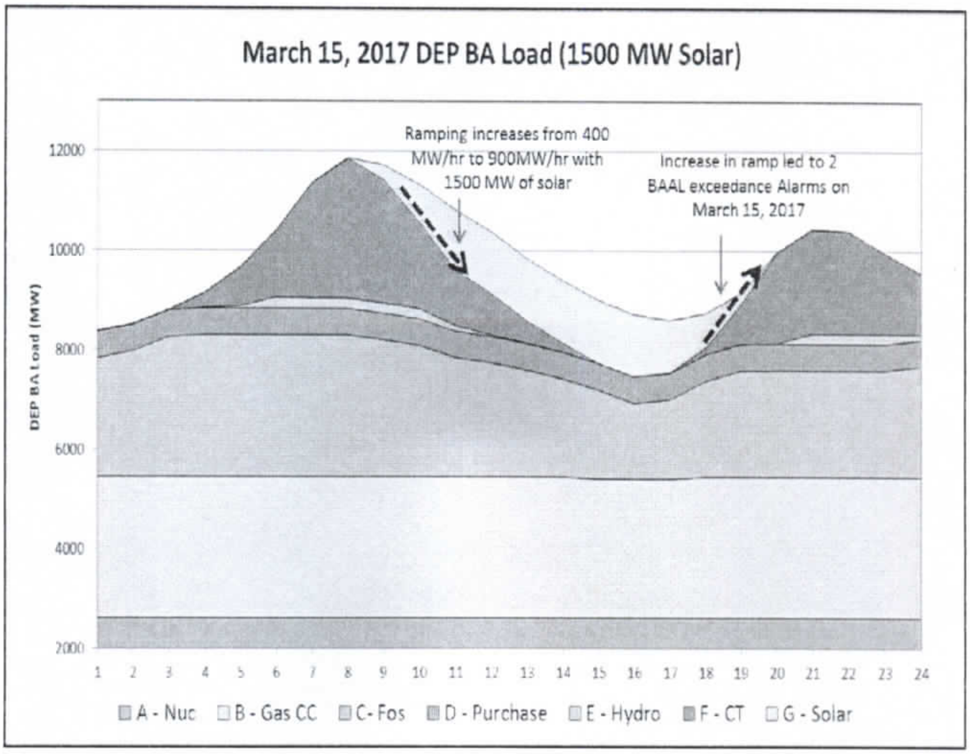
**Q. AS BACKGROUND TO ADDRESSING PUBLIC STAFF WITNESS METZ'S REQUEST THAT THE COMPANIES PROVIDE ADDITIONAL DETAIL REGARDING THE NEW BAL-002-2 STANDARD AND ITS EFFECT ON SYSTEM OPERATIONS, PLEASE PROVIDE AN EXAMPLE OF NERC BAAL "EXCEEDANCES" IN THE DEP BA DUE TO ITS HIGH LEVELS OF SOLAR QFS.**

A. As mentioned on page 28 of my direct testimony and discussed by Witness Metz on pages 4-5 of his testimony, DEP and DEC must comply with all applicable NERC Reliability Standards, including the BAL-001, BAL-002, and BAL-003 standards. The BAL-001 standard requires Interconnection steady-state frequency within defined limits by balancing real power demand and supply resources in real time and, as needed, to take action to support reliability. Prior to July 1, 2016, BAL-001-1, the then-effective standard, required averaging the BA's Area Control Error ("ACE")[5] over each 10-minute period *in the month* and at least 90% of those 10-minute average ACE measurements each month had to be less than or equal to an ACE limit, $L_{10}$. In contrast, the current BAL-001-2 standard requires BAs to manage their ACE to within an ACE limit *for each 30-minute period*. One BA ACE limit "exceedance" for 30 consecutive minutes is now a violation of the BAL-001-2 standard and is subject to NERC enforcement and penalty.

[5] NERC defines Area Control Error ("ACE") as follows: The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection. *See* Glossary of Terms Used in NERC Reliability Standards, p.2 of List of Terms, accessible at http://www.nerc.com/files/glossary_of_terms.pdf ("NERC Glossary of Terms").

Figure 2 shows a recent March 15, 2017 load stack, including the actual solar energy injections into the DEP BA. It shows the challenging ramping requirements that DEP is currently experiencing due to current QF penetration levels.

**Figure 2**




For this March 15th day, and similarly for any fall, winter, and spring load shape days, the BA experiences rapid up-ramp requirements in the late afternoon, early evening period ("late day period") due to customer load demand. However, that is when the solar QF energy injections into the BA are rapidly declining. In the late day period, the BA's load-following resources are operating at low output levels to accommodate QF energy

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injections; and therefore, the BA must meet increasingly steeper "net" ramping requirements to: (i) satisfy higher customer demands; and (ii) back-stand the deficit due to rapidly declining QF energy injections.

Due to this significant increase in "net" ramping demand for the late day period peak, DEP experienced two (2) BAAL Exceedance Alarms on March 15, 2017. DEP was able to respond and avoid having these "exceedances" become violations of the BAL-001-2 standard; however, increasing levels of solar QFs on the DEP system will increase risks of future NERC non-compliance.

**Q. AS FURTHER BACKGROUND TO ADDRESSING PUBLIC STAFF WITNESS METZ'S REQUEST THAT THE COMPANIES PROVIDE ADDITIONAL DETAIL REGARDING THE NEW BAL-002-2 STANDARD AND ITS EFFECT ON SYSTEM OPERATIONS, WHAT ARE YOUR PROJECTIONS OF "NET" RAMPING DEMANDS ON THE DEP BA AT 2,200 MWS OF QF PENETRATION LEVELS?**

A. At 2,200 MWs of QF penetration on the DEP BA, DEP will experience very steep "net" up-ramping and down-ramping demands. Figure 3 below shows a *near tripling* of the "net" down-ramping demand on the DEP BA at 2,200 MWs of QF penetration, from 400 MW/hour to 1,100 MW/hour. This is due to non-conforming increases in QF energy injections into the system, just as the system's customer load demand begins to drop. For fall, winter, and spring loads, following the morning peak, BA operators must ramp down DEP's load-following generation resources to match declining customer load demands. To now accommodate the QF energy increases after the morning peak, the BA operators must even more steeply accelerate the reduction of power output from the system's load-following resources.

**Figure 3**

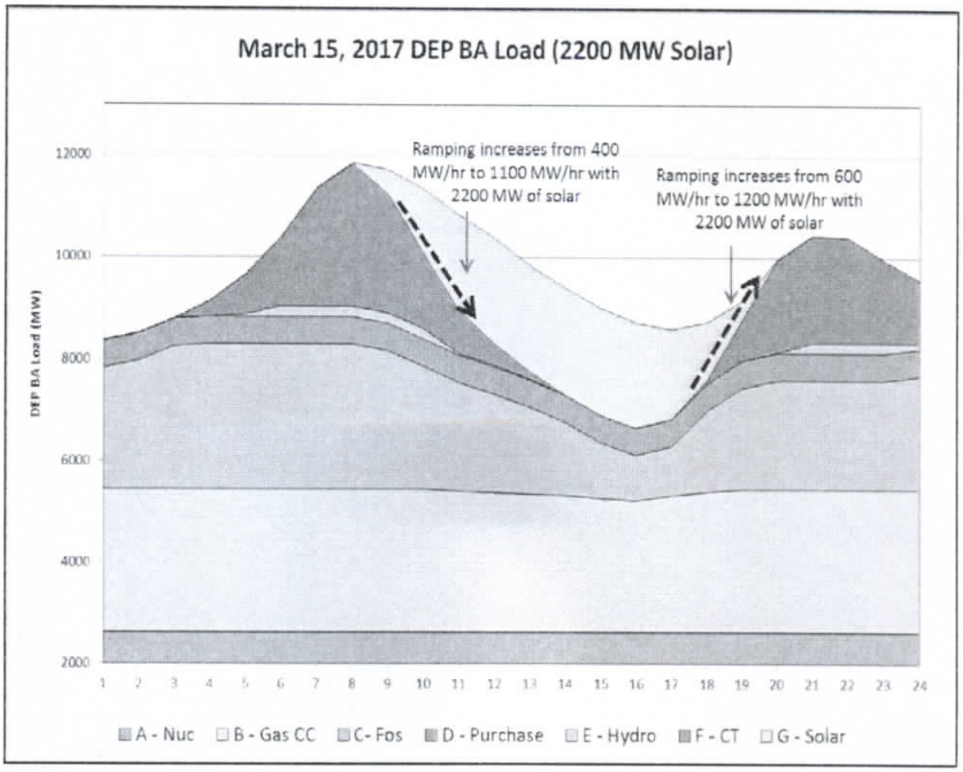


Figure 3 also shows the net up-ramping demand during that late day hours will *double* from 600 MW/hour to 1,200 MW/hour due to the rapid, non-conforming QF energy withdrawals, just when customer load demand increases for the evening peak. A 1,200 MW/hour up-ramping rate severely diminishes the BA's operational flexibility and imposes a higher risk operational environment. A generator failure or other disturbance, such as loss of transmission, would cause deficit energy on the BA that would result in NERC violations and serious challenges to providing reliable service.

**Q. WITH THAT BACKGROUND, PLEASE DISCUSS THE IMPACTS OF THE NEW BAL-002-2 STANDARD THAT WILL BECOME EFFECTIVE ON JANUARY 1, 2018.**

A. The currently effective version of the BAL-002 standard, BAL-002-1, considers only the "Loss of Generation" to invoke the deployment of contingency reserves, so that the BA experiencing the generator loss must recover to zero ACE or the pre-disturbance ACE within 15 minutes from the Loss of Generation event. Hence, the (i) loss of a DEP system generation asset; or (ii) a sharp reduction of QF energy injections in the BA due to the variability or intermittency of solar QF generation; or (iii) both occurring contemporaneously will increase the risk of non-compliance with the BAL-002-1 standard. As I discussed above in regard to the very steep late day ramping period, if DEP experienced a loss of generator disturbance event, or if during up-ramping the solar QF generation has a sharp decline due to sudden cloud cover, then there is increased risk that the DEP BA could violate the BAL-002-1 standard. It would also violate the BAL-002-2 standard.

The updated BAL-002-2, Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event standard, effective January 1, 2018, will replace the "Loss of Generation" contingency with a more robust "Balancing Contingency Event" covering a broad range of credible events, against which the BA operator must recover the resource-

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demand balance *within 15 minutes* of the contingency event. Balancing Contingency Events include transmission element contingencies – *such as the loss of any of the non-firm, curtailable transmission between the DEP BA and DEC BA*. The BAL-002-2 standard's purpose is:

> "To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event."[6]

NERC's Glossary of Terms used in NERC Reliability Standards defines a "Balancing Contingency Event" as:

> "Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less. A. Sudden loss of generation: a. Due to i. unit tripping, or ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or iii. sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE; B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE."[7]

In summary, the BAL-002-2 standard requires single contingency operations, planning, and response to broader and additional credible

[6] See BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, available at: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=BAL-002-2&title=Disturbance%20Control%20Standard%20%E2%80%93%20Contingency%20Reserve%20for%20Recovery%20from%20a%20Balancing%20Contingency%20Event&jurisdiction=United%20States

[7] *See* NERC Glossary of Terms, *supra* note 5.

contingencies that can create unexpected deviations in a BA's ACE, and requires restoration of the resource-demand balance within 15-minutes.

**Q. HOW WILL THE CONTINUED ADDITION OF QFs IN THE DEP BA ADVERSELY IMPACT DEP'S AND DEC'S DAY-TO-DAY OPERATIONS AND CAPABILITY TO COMPLY WITH BAL-002-2?**

A. As DEP experiences the connection of additional solar QFs on the BA, it will have to purchase increasing amounts of unconstrained and unscheduled PURPA energy – in excess of its operational ability to use the energy. DEP must then curtail that excess (or dump that excess into another BA). NCSEA Witness Johnson suggests that DEP ought to simply move the excess energy to DEC and deliberately rely on another BA's assets, such as DEC's pumped storage, to manage DEP's operational commitments.[8] He makes this suggestion even though the DEP and DEC BA's are only connected by hourly, as-available non-firm, curtailable transmission paths. Hence, the more mandatory long-term contractual commitments for operationally excess energy that DEP has, the more it must curtail to keep the BA in balance on a stand-alone basis.

Assume for example that DEP is exporting 1,000 MWs to a neighboring BA to try to manage its operationally excess energy, over hourly, as-available, non-firm, curtailable transmission, and that transmission is curtailed or a transmission facility contingency occurs resulting in immediate curtailment of the non-firm transaction. The loss of transmission action will

[8] NCSEA Johnson Testimony, at 214.

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create sudden resource-demand imbalances on *two BAs* that will require each BA to restore its resource-demand balance in a quick manner to avoid BAL Standard violations, as discussed above. Explained another way, if DEP were exporting the 1,000 MWs of operationally excess energy to the DEC BA over hourly, as-available, non-firm transmission, and a transmission contingency resulted in the immediate curtailment of the 1,000 MW DEC import of DEP's excess energy, at that moment, DEC would experience a 1,000 MW deficit, and DEP would have an excess of 1,000 MWs. It is important to note that operationally excess energy on DEP exists after DEP has reduced its units' output to the LROL, and therefore, DEP has no ability to reliably reduce output from its synchronous load-following resources. Therefore, due to the challenge of curtailing 1,000 MWs of QF energy in a quick manner (i.e. 15-minutes), DEP's system reliability will be increasingly challenged along with DEP's and DEC's compliance with NERC's requirements. Any ability to dump operationally excess energy to DEC or any other neighboring BA will, therefore, be limited by the more robust BAL-002-2 standard.

**Q. PLEASE CLARIFY WHAT YOU MEAN BY "NON-FIRM" TRANSMISSION.**

A. "Non-Firm Transmission" is defined as: "Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption."[9] Non-firm transmission is subject to availability on an hourly basis, dependent on whether the holder of the firm transmission is using its

[9] *See* NERC Glossary of Terms, *supra* note 5.

transmission capacity or other transmission customers have made transaction reservations. Non-firm transmission is effectively the "leftovers" of the scheduling process, where firm transmission that is not scheduled day-ahead is released for hourly non-firm use. Availability of non-firm transmission will change as reservations made by wholesale customers and other transmission customers change over time. Furthermore, load-following designated network resource additions, both within DEP and in other BAs, are likely to reduce available transmission capability in the future.

**Q. PUBLIC STAFF WITNESS METZ RECOMMENDS THE COMPANIES PROVIDE MORE DETAIL ON THE OPERATIONAL LIMITS OF THE "JOINT DISPATCH AGREEMENT" BETWEEN DEC AND DEP UNDER THE MODIFIED BAL-002-2 STANDARD. PLEASE RESPOND.**

A. With respect to JDA transactions under the BAL-002-2 standard, it is important to consider the intended purpose of the JDA, which is to transfer incremental economic energy from the Companies' synchronous, fully-controlled generation from the system with lower marginal costs to displace higher cost system generation on the other system. The JDA is not a tool for managing balancing, regulating, or operating reserve requirements. Moreover, the JDA does not set up a joint balancing authority. Pursuant to the Commission's June 29, 2012 *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, in Docket Nos. E-2, Sub 998 and E-7, Sub 986, which approved the merger of Duke Energy and Progress Energy

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Corporation (the "Merger"), DEP and DEC continue to operate as separate BAs and utilities, and each is responsible for its own independent resource planning and operations.[10] Put another way, the JDA is merely an opportunistic, economic, incremental-cost energy transfer tool, which relies on hour-by-hour, as-available, non-firm, curtailable transmission and does not reduce availability of firm transmission for long-term wholesale transactions of other network transmission customers. Moreover, because firm transmission reservations support transactions where a party has an actual firm transmission need. Accordingly, under the Companies' FERC-approved Joint Open Access Transmission Tariff, in order to use firm transmission to support such non-qualifying JDA transactions between DEC and DEP (or for that matter for PURPA dump energy transactions), DEP would have to un-designate DEP's load-following network resources to secure firm transmission, which would have serious, adverse impacts on reliability.

Under the BAL-002-2 standard, the curtailment of non-firm transmission would trigger a contingency event against which each BA would have to recover within a 15-minute period. Assuming the JDA is used for its intended purpose, and each BA manages regulation, operating, and balancing

[10] Regulatory Condition No. 4.1, which provides that "DEC and DEP acknowledge that the Commission's approval of the merger and the transfer of dispatch control from DEP to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA never being interpreted as providing for:

(a) A single integrated electric system
(b) A single BAA, control area, or transmission system
(c) Joint planning or joint development of generation or transmission
(d) DEC or DEP to construct generation or transmission facilities for the benefit of the other
(e) The transfer of any rights to generation or transmission facilities from DEC to DEP to the other, or
(f) Any equalization of DEC's and DEP' production costs or rates."

reserves independently, by curtailing excess energy when necessary, the JDA could plan to transfer economic energy from the Companies' fully-controlled synchronous generation to make hour-by-hour economic transfers. Under those conditions, each BA is more likely to recover from any curtailment of the non-firm energy transfers, because each BA would have the necessary responsive contingency resources to regulate energy up or down depending on the JDA energy flows from DEC to DEP or vice versa.

**Q. PLEASE RESPOND TO PUBLIC STAFF WITNESS METZ'S RECOMMENDATION THAT THE COMPANIES FILE THEIR CURTAILMENT PROTOCOL WITH THE COMMISSION.**

A. As noted by Public Staff Witness Metz, the Companies have provided to the Public Staff the current System Operations Reference Manual Carolinas, and are currently in the process of developing an operating procedure document for the management of system emergency curtailments of QFs and other non-QF generators on a similarly situated, non-discriminatory basis. The Companies have not completed this guidance document at this time, but commit to share the document with the Public Staff as soon as it is completed and will agree to file such procedures after discussions with the Public Staff.

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**Q. NCSEA WITNESS JOHNSON DISMISSES THE COMPANIES' SYSTEM OPERATIONS CHALLENGES ASSOCIATED WITH OPERATIONALLY EXCESS ENERGY AS "GROWING PAINS" TO BE EXPERIENCED AS UTILITY-SCALE SOLAR BEGINS TO DISPLACE FOSSIL GENERATION. DO YOU AGREE?**

A. No, I do not. System operators are charged with ensuring safety, reliability, security, and service to our customers. We are not allowed to replace operational discipline and integrity with acceptance of "growing pains," because hope and luck is not operational planning. We have to plan and then execute prudent operational discipline 24 x 7 x 365. In the current framework, the operational challenges will intensify as more than 2,200 MWs of solar facilities locate in the DEP BA. This growing level of PURPA solar interconnection is beyond growing pains.

Viewed another way, DEP will very soon have 2,200 MWs of solar facilities that will inject unconstrained, unscheduled, variable, and intermittent energy into the BA, in a manner that is non-conforming to load for most of the year. The adverse impacts to reliable system operations that I have described are challenging the system's capability to respond to abnormal system conditions, future load demand changes, and are causing risks to reliability and security conditions on the BA.

For the reasons I have extensively discussed in my direct and rebuttal testimony, and as recognized by Public Staff Witness Metz, the current and growing system operational challenges facing DEP and DEC are not merely "growing pains" to be accepted by the Companies as a temporary condition that will somehow resolve itself on their own. Instead, as set forth in the testimony of the Companies' other witnesses, it is appropriate to evolve the way in which solar QFs are added to and controlled on the Companies' energy grids to enable DEC and DEP to reliably serve our customers' energy needs.

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

A. Yes, it does.

BY MR. BREITSCHWERDT:

Q Mr. Holeman, do you have a summary of your direct and rebuttal testimony prepared to present to the Commission at this time?

A Yes, sir.

Q Would you please present it to the Commission now?

A Yes, sir. Good morning, Mr. Chairman, Members of the Commission. My direct testimony discusses the Companies' recent system planning and operational experience as increasing levels of solar qualifying facility, QF, energy is being injected into the Duke Energy Progress and Duke Energy Carolinas systems.

I provide the Commission background regarding how the DEP and DEC balancing authorities independently deploy their designated network and load-following generating assets through a Security Constrained Unit Commitment process to reliably provide firm native load service to their customers, as well as to comply with mandatory North American Electric Reliability Corporation Reliability Standards that enforce the provision of essential reliability services within each BA.

My testimony highlights for the Commission the current and growing operational challenges and reliability risks of integrating significant quantities of non-conforming solar energy into the balancing authority, including managing unscheduled and unconstrained solar QF energy injections with reliability limitations of the balancing authority's Lowest Reliability Operating Level; managing the real-time variability and intermittency of the unscheduled solar energy injections; managing the growing amounts of operationally excess energy and very steep down-ramps and up-ramps due to the non-conforming energy injections by solar facilities, particularly during the fall, winter and spring periods; and ensuring compliance with mandatory NERC Reliability Standards, specifically including the BAL-001, BAL-002 and BAL-003 standards.

I explain the Companies' obligation to operate load-following resources at or above their Lowest Reliability Operating Limit, or LROL, to meet upcoming late-day and next-day demand peaks and maintain reliable service. I demonstrate that the significant quantities of QF solar energy is now causing operationally excess energy in the Duke balancing -- DEP balancing authority during a growing number of hours on an increasing number of days during the fall, winter and spring periods. By early 2018, DEP is projected to have over 2,200 megawatts of solar facilities that will inject into the DEP BA more energy than the BA can reliably accommodate, causing DEP to increasingly operate in a reactive mode and with very limited situational awareness.

I would draw the Commission's attention to the graphic on page 2. Just hitting a couple of highlights here. This is a typical winter day modeled after a 2016 day. We have over-layed 2200 megawatts of solar which represents which we anticipate to be the case the first quarter of 2018 in DEP. This graphic illustrates the LROL, the Lowest Reliability Operating Limit, as established for that day. As you can see, the main point in this graph is if we drop below the Lowest Reliable Operating Limit at approximately 10:30 and we don't recover from that until approximately 1700. Also on this you will see where there's a couple of hours between 11:30 and 1500 hours where we are displacing nuclear generation. As a system operator, having this projection, looking ahead into the operating horizon, I have to be prepared to not violate the LROL. And opportunities such as curtailment, opportunities such as moving excess would be desirable in that operational plan, but in whatever situation I cannot compromise LROL.

My direct testimony explains how the generation-demand imbalance that is harmful to system frequency and the other operational risks due to the increasing levels of QF energy is challenging the DEP's balancing authority's capability to maintain compliance with NERC BAL Standards. I explain how a potential violation of the BAL Standards could cause a system emergency on the DEP or DEC balancing authority, resulting in unscheduled power flows, unnecessary and automatic firm load shedding, or potentially even cascading outages that could affect other balancing authorities in the Eastern

Interconnection. To mitigate these growing system reliability and operational risks, and the growing challenge of maintaining compliance with NERC's Standards, the Companies have proposed a clarification to the Standard Offer terms and conditions to include the ability to curtail QF's during imminent violations of NERC BAL Standards to avoid these system emergencies.

My rebuttal testimony responds to Public Staff Witness Dustin Metz' testimony concerning system operations, safety, reliability and regulatory compliance with regards to current and future NERC Reliability Standards. I agree with his conclusions that "continued growth in unconstrained and non-dispatchable generation will only serve to exacerbate the current system challenges" that I have addressed in my direct testimony.

I describe the Essential Reliability Services that the DEP and DEC balancing authorities must provide, and the role of NERC's Reliability Standards to enforce the provision of these essential services. I also explain the upcoming NERC BAL-002-2 standard to become effective January 1, 2018, which will require balancing authorities to manage the DEP and DEC systems to recover the resource-demand balance within 15 minutes of a "Balancing Contingency Event".

In connection with the BAL-002 Standard, I discuss the growing challenges facing DEP balancing authority operators as significant levels of non-conforming solar energy injections into the BA impose significantly steeper down-ramps and up-ramps associated with the morning and late-day system peaks. I explain that after the morning peak, solar energy generation increases as system load naturally decreases and, therefore, the balancing authority's assets must sharply reduce their output to maintain real-time balance. I also explain that as the late-day peak approaches, solar energy generation quickly decreases just as the system load naturally increases and, therefore, the balancing authority's assets must sharply increase their output to maintain real-time balance. These steep up and down ramps are challenging the physical capability of the balancing authority's assets to respond in real time to decrease and increase output.

I would refer the Commission to the second graphic. This is an actual operating day, March 15, 2017. And what this graphic illustrates is the non-conforming characteristics of uncontrolled and non-controlled solar as you see in the morning peak, and this is a typical winter-type pattern where you have cooler or colder weather. As our load peaks and then begins to drop, solar is picking up, thus going to the opposite direction, thus increasing the steepness of the down-ramp. And then in the afternoon as our customers in North Carolina demand more energy and our load picks up, solar is ramping up due to solar irradiance, thus increasing the steepness of the up-ramp. This also demonstrates the challenges with the ramping capability. This was with approximately 1500 megawatts of solar in the DEP balancing authority. We've seen an almost doubling of the morning down-ramp. And in the afternoon on this particular day, DEP experienced two BAAL exceedance alarms due in this case to operationally deficient energy.

I also explain the purely economic role of the Joint Dispatch Agreement between DEC and DEP. I discuss the limitations of the hourly, as-available, non-firm, curtailable transmission path between the DEP balancing authority and the DEC balancing authority. I emphasize that the JDA is not a tool for managing balancing, regulating, or other operating reserve requirements. Further, I emphasize that non-firm transmission between two balancing authorities is neither a prudent nor a reliable solution for managing the increasingly operationally excess solar QF energy now being generated in the DEP balancing authority.

Finally, I respond to Public Staff Witness Metz' discussion about potential "system emergency" curtailments of QFs, particularly on the DEP system, and explain the high likelihood of operational curtailments of QFs that will be required in real time to ensure compliance with NERC Reliability Standards and to avoid the growing risks to reliable electric service on the balancing authority as more QFs continue to come online. I describe the Companies' ongoing efforts to expand operating protocols for the management of system emergency curtailments of QFs and other non-QF generators on a similarly situated, non-discriminatory basis, and commit to share that protocol with the Public Staff as soon as it is completed.

I will conclude my summary by emphasizing for the Commission that the Companies' recent and anticipated system operations experience represent real and complex future safety, reliability and regulatory compliance challenges due to the very high penetration levels of solar and other QFs on each BA, in particular DEP. As a system operator, I am agnostic as to the type of generation technology connected to the system, as long as I can prudently provide reliable and secure services to our customers. Under the current PURPA framework, operational challenges will intensify as the more than 2200 megawatts of solar facilities connect to and inject energy into the Duke BA. My testimony supports the Companies' recommendations as a critically important initial step in evolving how solar QFs are added to the balancing authority to enable DEP and DEC to continue to reliably serve our customers in North Carolina, and comply with NERC Reliability Standards.

This concludes my summary.

MR. BREITSCHWERDT: Thank you, Mr. Holeman. Mr. Chairman, Mr. Holeman is available for cross examination at this time.

CHAIRMAN FINLEY: Cross examination of Mr. Holeman? Ms. Mitchell.

CROSS EXAMINATION

BY MS. MITCHELL:

Q Good morning, Mr. Holeman.

A Good morning.

Q Charlotte Mitchell, Counsel for NCSEA in this proceeding. Mr. Holeman, do you have both your direct and your rebuttal testimony in front of you?

A Yes, ma'am, I do.

Q Okay. I'd like to start with your rebuttal testimony first.

A Okay.

Q Is this working? Mr. Holeman, can you hear me?

A Yes, ma'am.
Q Okay. Mr. Holeman, would you please turn to pages 21 and 22 of your rebuttal testimony?
A Yes, ma'am, I'm there.
Q And just sort of generally I describe your testimony as expressing concern with NCSEA Witness Johnson's characterization of the system operation challenges that you describe as "growing pains". Is that a fair summary of your testimony?
A Yes, ma'am, the use of the word "growing pains" was at the point of this particular response.
Q Understood. And you've -- obviously you have reviewed Mr. Johnson's testimony; correct?
A Yes, ma'am.
Q And do you recall that however in his testimony that despite using the phrase "growing pains" he also describes the operational challenges that you explain in your testimony as being legitimate?
A Yes. And with the reference to growing pains, also, I remember that.
Q Understood.
CHAIRMAN FINLEY: Mr. Holeman, why don't you

pull that microphone around a little bit.

THE WITNESS: Oh, I'm sorry.

CHAIRMAN FINLEY: Just pull it around so you don't have to --

THE WITNESS: Oh, pull it to me. Thank you.

BY MS. MITCHELL:

Q And do you recall that he makes the point that while operational challenges and concerns are unavoidable and inevitable during any transition, it's going to be critically important for all industry participants and particularly the incumbent utilities to address these challenges?

A And I think my comments in my rebuttal testimony address the need to address these challenges. As a system operator my job is to ensure reliability, security and service to the customers in North Carolina, and that is my sole job. I'm agnostic to the generation type. That is my sole focus. As a system operator, I do not have the opportunity to have growing pains. That is not allowed in my discipline. We have to be prepared to ensure reliability and security. We also have to be planning to ensure reliability and security. And to refer to the challenge we face as "growing pains" implies to me that you're depending on fortune and luck and as a system operator luck and hope are not a plan.

Q Understood.

A So we have to plan for these intermittencies and we have to plan for these situations of excess energy and deficient energy.

Q And, Mr. Holeman, does Dr. Johnson use the words "hope and luck" in his testimony?

A No, but growing pains implies that.

Q Do you agree that he testified that the concerns are legitimate?

A Yes.

Q Okay. I'm going to move on. Let's turn to your direct testimony now. Mr. Holeman, I want to ask you a few questions about Figure 2 on page 12 of your direct testimony.

A Yes, ma'am, I've got it.

Q As I understand Figure 2, it depicts DEP load, Duke Energy Progress load in January --

A Yes, ma'am, 2016.

Q -- assuming -- 2016. Assuming 2200 megawatts of solar are installed in the DEP balancing area; is that correct?

A Yes, ma'am. The 2200 comes from what we believe to be the case in the first quarter of 2018, within the operational planning horizon.
Q Understood. And that would be in North and South Carolina?
A This would be in DEP.
Q In North and South Carolina -- which includes both North and South Carolina?
A It does include North and South -- we operate the balancing authority as a whole.
Q Understood. Okay. And to be clear this figure, Figure 2 on page 12 of your direct testimony is a projection of what might happen assuming 2200 megawatts of solar is installed in the DEP BA; is that correct?
A This Figure 2 takes actual operating history from January 31, 2016, and overlays 2200 megawatts of solar - given the operating experience we have with solar, imitating that particular pattern, so it is a projection. As a system operator, my job is to ensure that I not only am able to operate reliably in the current state but also in the operational planning horizon which could be the next hour, it could be the next day; it may be

the next week or the next year. First quarter 2018 is within a year of now so it fits within that operating planning horizon, and that requires me to have a plan to project and have a plan on how I'm going to deal with the intermittency and the uncertainty presented by these resources.

Q So to be clear, Mr. Holeman, Figure 2 is a projection? It is not representative of what actually happened on that day in January 2016?

A No. We actually had approximately 1400 megawatts of solar in 2016, January 2016. We've extrapolated to the, what we believe to be the case, the first quarter of 2018.

Q Okay, thank you. In response to a data request, Duke explained that Figure 2 reflects a mild winter day where the risk is the highest; that the demand on the system is well below the level of generation output that's required to maintain your operational obligations; is that correct? I know that's stated generally but is that correct?

A The LROL, the Lowest Reliability Operating Limit, represents that. The LROL represents -- and it's produced by the security constrained unit commitment process. It represents the lowest amount of generation that we can sustain and still meet our obligations for safety, reliability, security and service to our customers in North Carolina for the next hour, the next day, the rest of the week; it's in that near real-time operational space. And, if you look at this particular graph, you're right, this is a mild winter day, typical colder weather pattern, and you'll see the double peak, the double cresting pattern. That will happen day after day in a colder weather pattern. And the concern with the LROL violating, compromising the Lowest Reliability Operating Limit is, if you shut down resources to meet that valley that drops below LROL, you may not have them back based on the operating characteristics of those resources for that afternoon peak, which puts us in a deficit energy situation, which is equally as dangerous and presents an equally reliability risk as operationally excess energy.

Q Mr. Holeman, is this a week day or a weekend load curve?

A It - by the appearances of it, it appears to be a weekday curve?

Q A weekday?

A Weekday. I do not know that specifically.

Q So you don't know whether it's a weekend or a weekday.

A I don't know, no. It was built on January 31, 2016.

Q Okay. So, just to reiterate, on the type of day depicted in Figure 2, if the temperature is mild and it's sunny - the sun is shining - there is risk of over-generation because solar is producing and there's not much demand on the system?

A Well, the demand drops. That is the peak we'll -- that is the pattern we'll see day after day after day. After the morning peak, the demand will drop.

Q Okay. Mr. Holeman, on days like this - low load, mild weather days - is it possible that over-generation can occur even in the absence of solar generating capacity?

A Yes.

Q Okay, thank you. Mr. Holeman, I'd like to turn to page 23 of your direct testimony.

Specifically, I'd like you to refer to lines 10 and 11.

A Okay.

Q You testified that *there were 19 days and 71 hours when the DEP BA had operationally excess energy due to solar injections*; is that correct?

A That is correct.

Q Were these days when the temperature was mild?

A Not all of them. If you look at evidences in later graphics, the weather is -- it varies over that time.

Q When you say "varies", what do you mean by that?

A Well, in 2017, we have a variety of different load patterns -- a variety of different load temperatures.

Q So were these extreme weather days or were they days that were average temperature days, below-average temperature days?

A I don't know that I can describe them as that. As a system operator you deal with the system as it's presented to you. The load is what the load is. That's what our customers demand. And you deal with it as it's presented to you and you plan to operationally handle it as it is presented to you.

Q Okay. And on any of these 19 days or the 71 hours that you referenced, were these days weekends or week days?

A I do not have that information.

Q Is it possible that several of the days or many of the days or all of the days were weekends?

A It is possible that some of them were weekends.

Q But you don't have that information?

A I do not; no, ma'am.

Q Is it possible that some of the days were holidays?

A There's one holiday, that would be January 1st, so I doubt that there is.

Q Do you know how long these instances of over-generation occurred?

A How long in terms of hours?

Q Hours, minutes, seconds.

A Seventy-one hours, according to the direct testimony.

Q So you're -- just to clarify your testimony is that on 19 different days a total of 71 hours of over-generation occurred?

A Nineteen days and 71 hours where the Duke BA had operationally excess energy.

(WHEREUPON, the Court Reporter asked the witness to repeat his answer.)

A The testimony is already in 2017 there were 19 days and 71 hours when the Duke BA had operationally excess energy.

Q So were those minutes within specific hours or were those full hours?

A Well, if you look at the graphics -- if you look at the graphics, the operationally excess energy - Figure 9 for example - the operationally excess energy in that particular scenario is spread out over the hours 10 to roughly 1500.

Q Understood. But Figure 9 doesn't represent any of those 19 days, does it?

A That represents a day of -- no, it doesn't because it's 2200 megawatts of generation --

Q Okay, thank you.

A -- we're dealing with 1500 megawatts, 1600 megawatts now.

Q Thank you. Mr. Holeman, in response to a data request, Duke Energy Progress indicated that it was able to sell this excess energy to Duke

Energy Carolinas; is that correct?
A That is correct.
Q And isn't it true that Duke Energy Progress routinely sells energy to Duke Energy Carolinas, both pursuant to the Joint Dispatch Agreement and otherwise?
A Pursuant to the Joint Dispatch Agreement that is a opportunistic, economic exchange of energy on non-firm, hourly transmission and that is in place; that is true.
Q I'm going to repeat my question just for your benefit so that you can answer it. Isn't it true that Duke Energy Progress routinely sells energy to Duke Energy Carolinas pursuant to the Joint Dispatch Agreement as well as otherwise outside of the Joint Dispatch Agreement?
A I'm a system operator and so I'm not in the marketing area so I don't make arrangements. The Joint Dispatch is a bidirectional exchange. The energy goes from both DEP to DEC and DEC to DEP.
Q So are you saying that I should ask that question to another witness for Duke Energy Carolinas or Duke Energy Progress?
A I am not a marketer. I cannot answer that

question.

Q On those 19 days and during those 71 hours when Duke Energy Progress was experiencing over-generation, did Duke Energy Progress curtail any of the solar generating facilities that it owns?

A Not to my knowledge. We're working on the curtailment procedures now that will apply non-discriminatorily to all solar facilities, all really QF facilities.

Q And, Mr. Holeman, doesn't Duke Energy Progress own at least four solar generating facilities at this time which include the Warsaw generating facility, the Fayetteville solar generating facility, the Elm City/Fayetteville generating facility in Lejeune?

A I believe that to be the case.

Q So during those days of over-generation Progress did not curtail any of its own solar generating facilities?

A No, we did not.

Q During those 19 days of over-generation, did Progress curtail any of the other QF generating facilities for which it has contractual

curtailment or dispatch down rights?
A Not to my knowledge.
Q And why not?
A In following the operational challenges of excess energy, the curtailment procedures have to be operationally sensitive. They have to -- if you turn to slide 7 and 8, it illustrates the intermittency and the variability of solar. The tools that we will need in the future, the curtailment capabilities we will need in the future will have to respond to that kind of intermittency and uncertainty, and the tools that we have today are very difficult to apply in this type of rapidly changing, uncertain environment.
Q Understood. Is it true that Duke Energy Progress is under contract with non-solar generating QFs? So, in other words, QFs that are not solar generators?
A Yes, that is my understanding.
Q So it did not curtail any of those non-solar QF --
A Not to my knowledge.
Q -- during those days of over-generation?
A Yes.

Q Just for the record, Duke did not curtail any of the non-solar QF --

A Not to my knowledge.

MR. BREITSCHWERDT: I think he's answered the question twice now.

MS. MITCHELL: Just want to make sure the record is clear.

CHAIRMAN FINLEY: It's clear, proceed.

BY MS. MITCHELL:

Q Mr. Holeman, on page 16, lines 3 through 17 of your rebuttal testimony, you referenced or discussed --

A Hang on.

CHAIRMAN FINLEY: Hold on just a minute.

A Could you give me the line numbers again, please?

BY MS. MITCHELL:

Q Yes, sir. Lines 3 through 17, page 16, lines 3 through 17.

MR. BREITSCHWERDT: I'm sorry, this is direct or rebuttal?

MS. MITCHELL: Rebuttal.

MR. BREITSCHWERDT: Thank you.

A Thank you. Yes, ma'am.

CHAIRMAN FINLEY: What page?

MS. MITCHELL: Page 16, lines 3 through 17.

BY MS. MITCHELL:

Q You discussed Dr. Johnson's suggestion that DEP could manage excess energy by utilizing DEC's, D-E-C's, pumped storage capacity; is that correct?

A Yes.

Q And you testify that deliberately relying on another BA's assets, such as DEC's pumped storage, to manage DEP's operational commitments is not a valid suggestion. Is that a fair characterization of your testimony?

A I would say it's not a long-term sustainable solution.

Q Okay. Have --

A One thing to keep in mind, we operate independent separate balancing authorities. We have separate obligations to meet load. We have separate obligations to comply with NERC's mandatory reliability standards. We are two balancing authorities until we're not. And so that relying on non-firm transport between balancing authorities is not a long-term or sustainable solution.

Q Understood. That's actually a good transition to my next question. Have Duke Energy Carolinas and Duke Energy Progress explored whether combining the two BAs or coordinating their balancing operations could reduce challenges associated with solar-generated capacity or any other operational challenges for the matter?
A As a system operator we operate two balancing authorities in North Carolina until we don't. And my focus is solely on the operational challenges with the current strata -- the current status of having two balancing authorities. I would defer questions around policy to other witnesses.
Q I will do that. So is your answer that you do not know whether the Companies have explored that or that you would not be involved had the Companies explored?
A My job as the system operator is to focus on the two balancing authorities we operate now.
Q So you have no knowledge of whether the Companies have explored combining the two BAs.
A So I guess I'm struggling with the word "explored". I mean, have we talked about it?

Has it come up? Help me with the word "explored".

Q Have you analyzed it? Have you -- to determine the impact on system operations of operating two BAs as one?

A Not to the extent that we would need to handle the uncertainty and intermittency demonstrated on Figures 7 and 8 in the slides.

Q Okay, thank you. Mr. Holeman, back to your direct testimony, page 36.

A Page 36. Yes, ma'am.

Q You testify that the ability to curtail solar QFs will provide a measure of operational control during system emergencies; is that correct?

A Could you point out the line number, please?

Q Yes, I will do that, lines 2 through 4.

A On page 34?

Q Thirty-six?

A Thirty-six, 2 through 4. Yes, ma'am.

Q And in this proceeding both Duke and Progress, DEC and DEP, have asked the Commission to allow the Utilities to curtail QFs in the event of emergencies or imminent system emergencies; is that correct?

A I think we've extended it to include compliance obligations to NERC Standards.
Q Okay. Is it -- I believe I heard you testify earlier that Duke Energy Carolinas and Duke Energy Progress are currently developing their curtailment guidelines or procedures; is that correct?
A Yes, ma'am, and I think we have committed to get that to the Commission as they're completed.
Q So at this time you have -- Duke Energy Carolinas and Duke Energy Progress have not proposed any such guidelines or standards to the Commission?
A It is my understanding that those procedures are under development and they have not been presented to the Commission.
Q Okay. And I assume that, as you testified earlier, Duke Energy Progress and Duke Energy Carolinas will curtail its own solar facilities in addition to any other non-utility-owned generation?
A Yes, ma'am. The mindset would be we will manage this operationally excess energy through things we can control first. We can control curtailment. Through situational awareness and

the ability to curtail, we can control that curtailment and we would do that non-discriminatorily; we'd do that fairly according to the rules that are presented in the system operator -- system operators are not policy people. They are operators and we will apply the curtailment procedure as it is provided to us, which would be fairly and non-discriminatorily.

Q Understood. Thank you for that explanation.

A Sure.

Q Mr. Holeman, but is it fair to say that neither the Commission nor the Intervenors in this proceeding, including the Public Staff, have had an opportunity to review those procedures or comment on them?

A I don't know the body of stakeholders that have been involved in the development of those protocols. I know they are being developed inside, internally to Duke.

Q Okay.

A And we've made the commitments to the Commission to present that to them when it is completed.

Q Okay, thanks. Mr. Holeman, are you familiar with

the studies that Duke Energy has commissioned that analyze the operational impacts of solar at various penetration levels in the Companies' service territories?
A No, ma'am.
Q So you're not familiar with any of the studies that Duke Energy has commissioned that look at how to deal with or the implications of integrating solar PV into the Companies' systems?
A If you're talking about studies in general, yes, I've been involved in some of the study work in looking at how we need to respond to the growing intermittency and growing uncertainty that we're experiencing through operationally excess energy and operationally deficient energy.
Q So are you familiar with the study that's titled "Duke Energy Photovoltaic Integration Study Carolina Service Areas" published by the Pacific Northwest National laboratory in March of 2014?
A I am aware that that study had taken place but I'm not aware of any of the details.
Q And are you familiar with the study entitled "Duke Energy Photovoltaic Integration Study: Regulated 2020 Case for Carolina Service Area"

prepared in August 2016 by the Pacific Northwest National Laboratory?

A Not in any deep degree of detail.

Q And are you familiar with the study titled "System-Wide Impact Study for Interconnection: A Photovoltaic Distributed Generation PV-DG" prepared in December of 2016 by Quanta Technology?

A I'm aware of it. I do not have any detailed understanding of it.

Q And one last study to ask you about, the study that's entitled "Generation and Transmission Impact Study of High PV Penetration and Emerging Technologies in the Duke Energy Systems", the latest draft is dated November of 2016, also published by the Pacific Northwest National Laboratory.

A I know we have done studies with the Pacific National Lab. As a system operator, as I stated earlier, we operate the system. We are dealing with the here and the now in the operational planning horizon. We're dealing with the intermittency, the variability that we're seeing that are shown in Graphics 7 and 8 and then in the Figures 2 and 3 in the direct and rebuttal testimony. If you're asking me if I've been intimately involved in those studies, working with the laboratory subject matter experts, the answer is no.

Q Okay. So you have not been involved?

A No.

Q So to your knowledge then, those studies do not inform the systems operations for Duke?

MR. BREITSCHWERDT: Objection. I think he said he's not been involved in the study. So I don't know how -- I'm not sure how he can articulate --

MS. MITCHELL: He's also testi- --

CHAIRMAN FINLEY: Overruled. Overruled. Let's see if he can answer the question.

A Can you repeat the question, please?

BY MS. MITCHELL:

Q Right. So, Mr. Holeman, I'm trying to understand if these --

CHAIRMAN FINLEY: Just ask the question, please.

BY MS. MITCHELL:

Q Have you been involved in these studies? Have you been involved in the investigative work Duke has to do for these studies, any of these studies?

A I'm a system operator and my job is to operate the system. I have not been pulled aside from my role as a system operator and asked to participate on this analysis or this study.

Q So presumably, if these studies are looking at integrating solar PV technology into the Duke Energy systems - DEP, DEC, elsewhere in the country - is it reasonable to assume that the Companies would have solicited input from system operators?

A We -- our involvement as a system operator is mainly with NERC in the Essential Reliability Subcommittee. We also work with EPRI in some of the analysis they're doing in terms of integrating variable generation onto the grid.

I worked in the Essential Reliability Subcommittee at NERC. I was on -- I was a founding member of that group in 2014. And what we had the opportunity to do there was we had operators from California and Texas who were ahead of the curve in terms of solar integration, they came and explained their lessons learned.

And as an operator it's my job to learn from other people and their experiences. And they talked about back then challenges with operationally excess energy, challenges with operationally deficient energy, the ramping increases. That was the first time I heard the concept that these morning down-ramps and these afternoon up-ramps are approaching vertical, which means instantaneous change, and their guidance to us was to get ahead of it.

Q Thank you, Mr. Holeman. So these studies that have been conducted fairly recently do not address the issues that you describe in your testimony?

MR. BREITSCHWERDT: Objection. He doesn't know what the studies said because he's not reviewed them so I'm not sure how he can articulate --

CHAIRMAN FINLEY: Sustained.

MR. BREITSCHWERDT: -- whether the --

CHAIRMAN FINLEY: Sustained.

BY MS. MITCHELL:

Q Has Duke commissioned PNNL or any other group such as Quanta Technology to analyze the issues that you describe in your testimony, Mr. Holeman?

A It's my understanding, based on your questioning, that we have. I mean, I think we have --

MS. MITCHELL: Okay. Nothing further.

CHAIRMAN FINLEY: Other cross?

MR. STEIN: No, no questions.

MR. JOSEY: Thank you.

CROSS EXAMINATION

BY MR. JOSEY:

Q Hi, I'm Robert Josey with the Public Staff.

A Yes, sir.

Q I just a few follow-up questions. On page 18, lines 18 through 20 of your rebuttal testimony.

A Could you repeat that please?

Q Yes. It's page 18, lines 18 through 20.

A Okay, thank you.

Q You state the JDA is an economic tool and not a regulatory or balancing tool. Can you explain what you mean by that?

CHAIRMAN FINLEY: Pull the microphone up, Mr. Josey.

A Yes, sir. The Joint Dispatch Agreement in its design is an economically driven, opportunistic exchange of energy between DEP and DEC. It came about during the merger and it was set up to do that, and it has performed that way since its implementation. And it's intent is an economic exchange of energy on hourly, non-firm transmission. And my point was, if a balancing authority is depending on a central reliability service such as ramping, such as dealing with this operationally excess energy that we're seeing in terms of characteristics, it is not prudent utility operation and system operator discipline to depend on hourly, non-firm transmission to conduct that business.

BY MR. JOSEY:

Q And could DEP or DEC have -- do they have other places they could sell this energy to? PJM?

A In theory, you could but you have to remember these operationally excess energy, the load is dropping. You have to have a willing partner to exchange it. Again, I'm not a marketer, but you have to have a willing partner to exchange this energy and, if you don't need it, you don't need it. And that speaks to the nonconforming nature that we're seeing in our operating experience in solar. On that morning peak after our customer demand begins to drop, solar is coming up based on the sun's irradiance. And during that time it's difficult and you certainly couldn't depend on it from an operational discipline to find a willing partner to take that excess energy. But I am not a marketer, I have never been a marketer, I'm a system operator and I don't do that kind of business.

Q One other question, we -- you stated earlier that there were 33 instances of over-generation in 2016, and 19 in 2017, of your direct testimony. Do you know if any dispatch down instructions to solar facilities with which Duke had negotiated contracts that would allow for dispatch down instructions to be given, were any of those given during those days?

A For the balancing authorities in the Carolinas, I am not aware of that.

MR. JOSEY: Thank you very much.

CHAIRMAN FINLEY: Redirect?

MR. BREITSCHWERDT: Just a few questions, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. BREITSCHWERDT:

Q Mr. Holeman, so Ms. Mitchell asked you a couple of questions about over-generation events and whether they've occurred in the past in the absence of solar. Would you explain to the Commission your experience over the last 12 to 18 months, as you identify in your testimony, of the amount of over-generation events and how the over-generation events that are occurring as a result of QF solar are different than what you've experienced in the past?

A Certainly. So what we're seeing in terms of this winter pattern -- keep in mind the winter pattern is a good illustration of it and that is colder weather-type patterns, it's that double peaking situation -- what you run into is that decline in the morning of customer demand and the increase in solar generation. That non-conforming characteristic of generation creates the operationally excess energy, and this will happen on many, many days with the winter pattern over day after day after day. Our historic situations with operationally excess energy rarely happen. We're seeing it happen much more frequently given the winter-type double cresting pattern.

Q Thank you. And you mentioned double peaking in a response to Ms. Mitchell earlier and you mentioned it again. And can you just clarify for the Commission when this double peaking occurs during the year, whether it occurs on weekdays or weekend days or holidays, and what are the implications of trying to manage the system on a double peaking day?

A Certainly. So when I say double peaking, it's the typical winter pattern and it's driven by customer demand. Customers, as they get up and start processes in the morning the demand goes up. And in the winter, in an extreme winter, a colder condition and even milder winter temperatures, you'll see the demand increase very rapidly in the morning. And because there's common weather in a lot of cases that time of peak is typically 0720. It's odd. People are creatures of habit and you can predict, barring school closings or something like that, you can predict the peak at 0720. 0720 in many winter months the sun is not up. And so it crests and then it begins to drop as people go to work and they begin processes at work, and at that point and time the solar is coming up. So in the afternoon people return home, heaters kick in, and the load again crests again, typically if you have comparable weather, at a lower peak than the morning peak. But at that point and time it could typically happen 1700 and later, sun going down in many months of the winter. And so our customer demand is going up and our solar generation is going down, again nonconforming. Those ramps are becoming more vertical; the down-ramp in the morning and the up-ramp in the afternoon, and to an operator instantaneous change is extremely difficult to manage. There are physical limits to our resources and it's very difficult to manage instantaneous change.

Q Thank you. And Ms. Mitchell asked you a number of questions about certain studies that Duke Energy as a corporation has initiated or commissioned from the part, excuse me, the Pacific Northwest National Lab and Quanta, and you testified that you're not familiar with those studies. If those studies related to the Companies' NERC Compliance and the ongoing compliance with new NERC Standards that are going

to affect the Company with the new planning horizon, is that something you would be familiar with?
A Oh, certainly. We would want that information.
Q And you would be intimately involved in planning for those studies?
A Yes. Any time you take a concept or a theory and need to apply it to real-time operations you've got to involve the operators that are going to have to deal with it. My operating experience, at 31 years in operations, you do not want to surprise system operators. You do not want to test theory without ample research, without ample testing offline of processes. We cannot depend on hope. We cannot depend on luck. Our job is to be ready, to be ready for the unforeseen. I always describe it as this - reliability is operating the system within its limits. Those limits to a system operator are often given to them by the asset owner and operators. Security is prepositioning the system to land reliably after an unanticipated event. Things happen. These are complex mechanical, electrical, hydraulic, thermal, combustible systems and

they're very complex and they do fail. And so, as an operator, I have to be prepared to preposition the system to withstand those contingencies and land within my limits. So we'll take all the help we can get.

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

CHAIRMAN FINLEY: Questions by the Commission? Commissioner Bailey.

EXAMINATION

BY COMMISSIONER BAILEY:

Q Good morning, Mr. Holeman. How are you doing today?

A I'm doing good. Thank you.

Q My question is, I'm trying to understand the LROL --

A Yes, sir.

Q -- concept with NERC. Over the last six months, you're not saying that Duke Energy Progress violated that threshold, are you?

A No, sir.

Q You're just saying due to all of the excess generation on the system, mild winter days you were approaching that and you were able to

basically sell power back to DEC through the JDA to make sure you didn't violate that line; is that right?
A Yes, sir.
Q I notice that most of the time, the nuclear loads in DEP are below that level. You were running around 4500, 5000 megawatts and I guess you got what, 3200 or so megawatts of nuclear.
A Roughly.
Q And from a priority standpoint, and what bothers me is you keep saying "non-discriminatory". Would you not discriminate a lease for your nuclear plants before you guys will start backing off some of your nuclear loads in terms of, if you really got into an issue where you had to start releasing loads, you would do your fossil plants first before you do your nuclear plants?
A Yes, sir. And I think that's within the concept of the Lowest Reliability Operating Limit. We're going to do as much as we can to manage these valley ramps and the extreme ramps above that LROL. Once you get below it, you're creating that operationally excess energy and you're compromising your operational plan moving

forward. We will curtail or at least dispatch down the resources we have capability to. There are limits in that. The asset owners tell us how low they can go and then they're respecting performance issues, they're respecting environmental limits. We depend on the asset owners to give us those limits but we will do everything we can reliably do to manage the load and stay above LROL. Nuclear is a base-loaded resource that provides Essential Reliability Services, and my operating experience is that operationally they are very difficult to move.

Q I guess there's been some terms, discussion, a lot of discussion in the testimony about exactly what constitutes an emergency system or emergency --

A Yes.

Q -- is that actually when you get to the LROL, that's when you would declare a system emergency?

A Emergency is an interesting word. It's often -- in NERC parlance if a word is capitalized, there is a NERC definition for it. Emergency is always not capitalized so it's in the eye of the beholder. To a system operator, any time you are reaching a place where you're fixing to go into an unknown state or an unplanned for state, operators need to take action to avoid that or get out as quick as you can. And my point would be, regardless of what your definition of an emergency is, if a system operator is faced in the real time or in the operational planning horizon of violating, compromising LROL, they will do whatever they can within the limits they're provided to not compromise LROL.

Q Okay.

A And I would include compliance with NERC mandatory standards. Those are not just rules, they were established based on outcomes of really bad events - the Northeast blackout in 2003. I think a lot of times the public can consider they're just rules but they are based on real operational situations where situational awareness was compromised, where tools weren't quite where they needed to be, and it really shines the light on the importance of system operators. Really bad things can happen when they lose situational awareness or they're tools aren't capable of keeping up with the situation they're facing.

COMMISSIONER BAILEY: Thank you, Mr. Holeman.

A Yes, sir.

CHAIRMAN FINLEY: Other questions? Commissioner Brown-Bland.

EXAMINATION

BY COMMISSIONER BROWN-BLAND:

Q Good morning, Mr. Holeman.

A Good morning.

Q Just a few questions. So a minute ago I believe when you were discussing with Ms. Mitchell you indicated that there was a time that you participated in some session or conference whereby guidance was given to get ahead of these challenges that we've been discussing this morning?

A Yes, ma'am. I was a part of the NERC Central Reliability Subcommittee that in 2014 was established to look at the changing generation mix. That's the role of NERC - to stay ahead of some of these things to provide kind of national North American kind of perspective on it. And in that setting you had people from EPRI and other research organizations, you had solar advocates - GE, and solar developers in that room - you had balancing authority operators, transmission operators, and you had policymakers, and the purpose was to recognize the changing generation portfolio, the increasing intermittency and uncertainty, and how do we position ourselves to be able to operate reliably and securely. And the core message out of that was there's two at its core, two essential reliability services. One is frequency management and the other is voltage management. And all of my direct and rebuttal testimony is about frequency management. And my peers and fellow industry members from California and Texas talked about the challenges with the operationally excess energy, the ramping that they had experienced and, as a lesson learned, encouraged us to learn from their operating experience. So that's been my experience at the NERC, the Essential Reliability Subcommittee, that is -- or task force -- it has now become a subcommittee in an ongoing effort at NERC to stay ahead of this.

Q So --

A And it's agnostic to the technology. Essential Reliability Services apply no matter your generation mix. I'm sorry, I didn't mean to interrupt you.

Q So at that point in 2014, you were dealing with the very real issues that were being seen, these things were already occurring?

A I think in 2014, we would begin the solar build out and I think we saw -- we were seeing what was being experienced in these other areas and we wanted to be involved in that discussion. I had just come off being the Chairman of the NERC Operating Committee. And in that role I was on the -- I was put on the ERSTF, the Essential Reliabilities Task Force, at the time and I remained on it after I rolled off of my Chairmanship because of the importance looking ahead.

Q So prior to that time, that being 2014, going back to the 70's when there was prior discussion of solar and then we come up to the 2000's and we start seeing renewable energy portfolios and standards and such --

A Yes, ma'am.

Q -- where solar becomes part of the public discourse and people are expressing a desire to move towards that type of energy. Had there been work around, from an operator's point of view, work around these kinds of issues? Were they anticipated?
A I think we anticipated it. I think what we're seeing -- and this was the experience in California -- if you look at the graphic we provided on the California projections, they projected out solar growth and renewable growth generally and the actual growth exceeded their projections, and I think that's what we're seeing, too. I think the recognition of the scale of, in our case in DEP the solar resource, it was 1400 first of the year roughly, it's 1600 now, we're projecting 2200 first quarter of 2018. That is a lot of generation subject to the intermittency and uncertainty that is characteristic, at least of our operating experience with solar resources. That is a significant situation for a system operator that they need to have their arms around. We're trying to prepare operators. We have no option.

Reliability and security is my job.

Q So if that were the desire and solar would continue to grow, albeit in a more planned coordinated fashion of some sort, but if solar were to continue to become, to continue to grow and become a greater source there, operators would be able to handle it?

A I think operators under the existing tool set, I'm not sure they could. I think what we're saying in the testimony is that we need more control. We need more operational control, central control of that aggregate amount of solar. It's the largest aggregate generation in the Carolinas - 2200 by the first quarter of 2018. There's no other generator that's of that size. And certainly in my 31 years of operating experience I know of no generation type at that scale that displays the intermittency and the uncertainty that solar does, and I would refer you back to my slide 7 and 8 in the direct testimony. But I think what we're saying is we need more central control, more operator control, the ability to curtail is part of that and then as you go down those are the things I can control, those are the things an operator can put their hands on. I think that's -- that is my recommendation as we move forward into a new framework.

Q But to date at the current level you have been able to handle -- you have been able to address and deal with it without falling below the balance and requirements and NERC standards?

A Yes, ma'am. We've used that economic exchange of energy on non-firm hourly transmission to accommodate that. But as solar continues to grow that hourly non-firm transmission is just not as sustainable or a dependable way to do that.

Q So when the Company says this has been the first opportunity to speak to the Commission about the impacts of these challenges, that's reference to actual problems and challenges that's been encountered as opposed to foreseeing what might come in the future?

A I think it's both. I think we're experiencing -- my direct and rebuttal testimony spoke to two balancing authority ACE limit exceedance alarms that occurred on March 15th. We're seeing that type of challenge now. The operators in DEP did a fantastic job of responding to that and not allowing an exceedance alarm to turn into a violation of BAL-001, but those are indication to an operator that is, if solar continues to grow or really any intermittent resource grows to the scale that we're talking about, we have got to be operationally prepared for that. We have to prepare our operators in a way that they are ready for this challenge. We cannot simply hope and depend on maybe the sun will shine all the time. We just can't -- hope and luck are not a plan. I hate to keep saying that all of the time but for an operator -- we beat that into their heads -- hope and luck are not a plan.

Q But I guess what I'm asking is so now you've got issues that you're dealing -- well, always you've had issues that you deal with real time, you graph with --

A Yes, ma'am.

Q -- and get your arms around and that's what you've been doing, but you also anticipate ahead of time, correct?

A Yes, ma'am. Yes, ma'am, that's part of our job.

Q And so if we look back maybe at 2010, you had some ability to see some of what you describe as a challenge. For example, we have always known the load pattern; that there's heavy use in the morning --

A Right.

Q -- there's heavy use in the late afternoon or the early evening there's a dip. I mean, that usage pattern we've known about that. We know that solar is an intermittent. We know when the sun shines and when it doesn't. So on some level the Company made plans to deal with this type of energy coming onto the system?

A I think I would say that you're -- you're correct. The winter load pattern is nothing new. We've experienced that in my entire 31-year career. That's always been the typical winter load pattern. We know that we have to balance that valley period in the morning when the load's coming down and then in the afternoon when it comes up. I would say this though, I don't know that anybody anticipated in 2010, the growth of an intermittent resource to the extent that it's, by a fair amount, the largest generation aggregate resource in the Carolinas. I know I didn't, I did not anticipate that. I can only speak for myself.

Q So the amount of growth or the rate of growth, that is the thing that caught the Company unawares.

A I wouldn't -- I can't speak for the entire population of Duke Energy. I would say, from my experience in the ERSTF at the NERC level, that is the -- that has been the experience as related to us from my peers in California and Texas. And what we're trying to do is stay ahead of that and not have to learn the same lessons that have been relayed to us through the NERC and Essential Reliabilities Task Force in the Carolinas to hopefully find a better path forward.

Q So, in 2014, coming out of your work with NERC when you understand and come out with the guidance to get ahead of this, what kind of steps did you start to take at that point?

A In DEP, we worked on the information we had through information we get from our system and we were also using a state estimation algorithm to project what we believe is the solar output. And the DE folks, the DEP operators and engineers have done a very good job to understand, to understand the intermittency and the uncertain of solar. And I think that's -- I think that is evidence in the fact that we've stayed reliable and we've not had any violations. But the concerning thing is we're seeing more of these exceedance alarms.

Q So up to this point would you say you have stayed ahead?

A I think we have operated reliably and we have operated in a compliant manner.

Q And then a couple of times you've mentioned in regard to curtailment about maybe the tools that you would want aren't there or you don't have everything that you need --

A Yes, ma'am.

Q -- but you have some tools. Is there -- are you speaking of technological tools or what kind of tools?

A I think at the start - and this is true for a lot of operational procedures - at the start I think you've got to clearly define what the objectives are. And in this case, as we've talked about earlier, it's got to be fair, non-discriminatory.

We own some of this so we can't have that appearance of you favoring Duke versus other -- as an operator I'm agnostic to that. I'm agnostic to the ownership of it. I'm just dealing with the reliability and security, in this case, the balance of the situation. So, first of all, you've got to line up what it is you're trying to accomplish and then you get it down on paper that operators can understand and then can you train them on it. And in this particular case, given the intermittency and the volatility, the uncertainty of the resource, the characteristics, we will need technology, we will need the ability to have more situational awareness at the level of the generators so that we can work with the generator owner/operators. We do that all of the time. We welcome interaction with solar developers and solar owner/operators to help us figure it out. Reliability and security, it impacts everybody and we fully understand that and we will have to work with that group of stakeholders, including the Commission, as we've committed to providing that protocol to you all. But my belief would be automation would be a component of that given the rapid nature of this intermittency. I hope I answered your question.

Q You did and I think that I understand that your Company is -- one of the things they're asking for is a contractual tool or some other kind of tool. But, in addition, I was just focused on wanting to know from you are there technological tools that are needed, additional tools that are needed that aren't present today.

A I think our opportunities and our interaction with EPRI will open our eyes to some of those and help us to be informed of some of that. Our continued interaction, although I'm not on the ERSTF anymore, we have Duke employees that are and some of the research that's being done -- I know that a lot of the national labs are doing research. We're not alone in this and I think most balancing authorities are having this conversation. I think the difference for DEP is just the large scale of the development.

Q But in terms of being able to curtail, are there other technological tools that are needed to aid your ability to curtail?

A We will need -- we will need more than just phone call driven protocols to be able to deal with the intermittency and uncertainty of the operating characteristics of solar based on our current operating experience.
Q And, to your knowledge, is that in the future? Do you see that being worked on either at the Company or out in general in the world of electric utility?
A Yes, ma'am, and what that speaks to is situational awareness. Our ability to understand what the system is and have some insight into what's going to happen in the next couple of hours, days and such, and we will need to develop that situational awareness with solar developers, with solar facilities, with solar owners and operators, just like we do with nuclear owners and operators and fossil owners and operators, and hydro owners and operators. So, yes, ma'am, we will need --
Q And the goal and the result of that is to be able to effect curtailment?
A In a fair and undiscriminatory (sic) manner; yes, ma'am.

COMMISSIONER BROWN-BLAND: Thank you.
A Yes, ma'am.

EXAMINATION

BY COMMISSIONER BAILEY:
Q Some of her questions precipitated another question by me, Mr. Holeman.
A Yes, sir.
Q Does DEP have some constraint issues with transmission or distribution systems that -- I know we're looking at this from a centralized standpoint but I'm sure there may be some transmission constraint issues out there that really complicates -- further complicates the excess generation at different locations within the DEP system.
A My operating experience is generally at the bulk electric level, 100kV and above. I'm not a subject matter expert on the distribution system and so I really can't speak to that. Congestion on the transmission system happens all the time. It is a giant machine connected throughout the whole eastern interconnection, and congestion and outage and things like that happen all the time. Our assets are well-run by our asset owners. We

have very good availability but they are subject to contingencies, to forced outage; they are subject to maintenance outage. So, if you're asking me can congestion occur, it makes the problems worse, it certainly can.

COMMISSIONER BAILEY: Thank you, sir.

CHAIRMAN FINLEY: Questions on the Commission's questions?

MR. BREITSCHWERDT: No questions.

MR. STEIN: One question, Mr. Chairman.

EXAMINATION

BY MR. STEIN:

Q Good morning, Mr. Holeman. Peter Stein on behalf of SACE.

A Yes, sir.

Q In response to Commissioner Brown-Bland's question about tools to address some of the issues that you've discussed in your testimony. One issue that you've discussed is the difficulty of forecasting the injection of the solar onto the grid --

A Right.

Q -- is that correct?

A Yes.

Q In response to the Commissioner's question, you referred to peers in other parts of the country including in California; is that right?
A Yes. There were several representatives from California on the ERSTF and I think they remain on the ERSTF.
Q Are you aware of forecasting tools that California is using to address solar that has been added to its system?
A So I'm not an expert in California operations. I know people there but I can't speak with any certainty as to what they're doing, I can only tell you what we're doing. We recognize the importance of being able to forecast solar irradiance. We've got meteorology (sic) on staff at Duke that are working on that. We're actually engaging with EPRI on a project that it's looking into, the solar irradiance forecasting. I think that's a necessity moving forward. It speaks to situational awareness -- I'm sorry -- it speaks to situational awareness for the system operator and we will be engaged in that. The scope and scale of the penetration in DEP makes that a necessity. We've got to be at the table I think

as do the solar developers' owners/operators.
Q But just one final question though, the issues that you discuss in your testimony about forecasting solar, the tools and methodologies that you've discussed would help to alleviate those concerns moving forward?
A I think it helps. The ability to forecast - it's just like load - the ability to forecast load does not make the challenges of balancing easier, it just gives you more information to be prepared. Operating the system is not for the faint of heart. It is a difficult job that is a different challenge every day. And the more tools you can give to operators to help them be ahead of it to that pre-positioning aspect that we talked about earlier of the security and reliability, the more tools you can give them the better job they'll do. It doesn't make it easy but the better job they'll do for the interest of all of the stakeholders, our customers in North Carolina and the asset owner/operators.

MR. STEIN: Thank you.

MR. BREITSCHWERDT: Mr. Chairman, that did raise one question very briefly.

EXAMINATION

BY MR. BREITSCHWERDT:

Q Mr. Stein asked you about California and California's experience with forecasting. And, to the extent we're using California as a benchmark of what North Carolina may want to do, you had mentioned earlier that during the Essential Reliability Task Force you participated in in 2014, you got guidance from the California system operators about their experience. Is that a direction that we as a state want to go and you as a system operator want to?

A So California is different than North Carolina. It's -- that goes without saying. What I would say in response to that would be we need to learn from the operational experiences in California. We need to engage with the folks there, the owner/operators of the assets that -- system operators, the operational planners, the operators, the operational planners, the transmission planners, generation planners, and learn from their experience. There's one tenet of human performance and that is learn all you can so you don't repeat the bad stuff. My dad used to tell me that all the time. If you don't know your history, you're bound to repeat the bad stuff; same thing with lessons learned. And so I think our engagement, and it is, needs to be at that ERST level, talking to the operators in California about their experiences, what works and what doesn't, and how to stay ahead of the curve. That's the key. I think our challenge is going to be to stay ahead of the growth of solar resources in DEP and I think we can learn from California, and we should. Did I answer your question?

MR. BREITSCHWERDT: Yes. Thank you. That's all I have.

MR. JOSEY: I just have a quick question.

EXAMINATION

BY MR. JOSEY:

Q In response to a question by Commissioner Brown-Bland, you talked about the tools you needed and you mentioned automation a couple of times. Can you explain what you mean by automation?

A So what I mean by automation is we need the ability to have situational awareness information on any asset, not just solar, on any asset especially that scale. You're talking about 2200 megawatts of aggregate generation in the first quarter of 2018. We need information -- we need some of the information that the owner/operators are seeing. When I talk about that I'm talking about that the SCADA. I'm talking about information that comes back to the central control center that allows them to gain operational experience with the asset. So when I say automation, it may be the better -- the better word may be transparency of information, of data.

Q As far as ways to communicate with these solar facilities that are causing this issue, are those some of the tools you're talking about, automation of being able to -- if you have to curtail those, is there an automated way of doing that, is that --

A Yes, there should be no surprises. If we're moving in the right direction, we're exchanging information transparently with the operators, owner/operators of many types of generation so there are no surprises. In the world of a system operator surprises are a bad thing, and that would go to operators of solar, too. I'm sure they don't like surprises.

Q And you think this is something that could be taken care of maybe at the interconnection level?

A I'm not in that area of work. I'm not a subject matter expert. I just know it needs to be done. And I believe the suggestions and the recommendations from Duke Energy help in that.

Q And then one final question on -- can you just talk about the LROL and how it interplays with the BLA (sic) standards, violations? I mean, if you go below the LROL, are you automatically violating a BLA (sic) standard?

A No. The LROL, interestingly enough, the LROL, the Lowest Reliability Operating Limit, is not a NERC term. It is a Duke-generated concept. It's not a new concept but that measure was developed out of our operating experience in DEP. And there is not a reliability standard requirement that speaks to the LROL because it's not a NERC term. But in the concept of ensuring reliability and security and service to our customers in North Carolina, it is vital because it draws the line coming out of the security constrained unit commitment process it draws the line as to how low you can go. And it takes into account the here and the now, the real time, plus that operational planning horizon which could be the next hour, the next day, the next couple of days. It's the perspective of the system operator and it gives them the guidance I don't want to drop below that because if I do I can't be assured that the resources I need to meet tomorrow's peak are going to be there. And one thing about a winter pattern in the winter season, you can go all the way to the Polar Vortex or go to the cold periods this year, it is often in the Carolinas that you will see a really cold day followed up with a really mild day two or three days later, or visa versa, a really mild day followed up with really cold weather a couple of days down the road. That's where LROL really comes in because if you shut down to meet the mild weather and you can't get it back to meet the peak weather, that's a serious problem, and that is a problem that operators, by the nature of their job, cannot allow to happen. It's part of their role in the interconnection to protect reliability, to protect security and protect service to our customers, in this case in the State of North Carolina.

Q So, if you were to go below the LROL, you may not be able to ramp up quick enough to meet the next peak demand and, therefore, you could violate a BLA (sic)?

A Yes, I mean, it could translate into violations. And from an operator's perspective, you used the word "may", based on the information we have the LROL is an accurate indication of problems if you violate it. So, gray is not a good place for system operators. They need definitive action to take.

CHAIRMAN FINLEY: The Commission will take a recess until twenty-five until twelve, twenty-five until twelve.

(Recess at 11:23 a.m., until 11:35 a.m.)

CHAIRMAN FINLEY: Let's come back on the record.

Mr. Holeman, I think we're through with you. Thank you for coming. You may be excused.

A Thank you very much.

(The witness is excused.)

MS. FENTRESS: Mr. Chairman, Duke would like to call the panel of Ms. Bowman, Mr. Snider and Mr. Freeman up to testify, please.

CHAIRMAN FINLEY: We're going to go until 12:30, then we'll break for lunch, and then we'll come back at 2:00 o'clock. That will give plenty of people an opportunity to sharpen up their questions and make the afternoon run smoothly.

(Laughter)

**PANEL OF KENDAL C. BOWMAN,**
**GLEN A. SNIDER and**
**GARY FREEMAN;** having been duly sworn, testified as follows:

MR. SOMERS: Beginning with Mr. Snider, would you please state your name for the record?

A (MR. SNIDER) Yes, my name is Glen Snider and I work with Duke Energy, 400 South Tryon, Charlotte, North Carolina.

MS. FENTRESS: Do you want me to take over?

DIRECT EXAMINATION

BY MS. FENTRESS:

Q And, Mr. Snider, did you cause to be prefiled in this docket on February 21st of this year 40 pages of direct testimony?

A I did.
Q And do you have any changes or corrections to that direct testimony?
A Yes, I do. On page 37 of my direct testimony, footnote 3 should not read "ID", it should instead cite "Order setting avoid cost input parameters issued on December 31, 2014, in Docket Number E-100, Sub 140 at page 56".
Q Thank you. And with that correction, Mr. Snider, 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.

MS. FENTRESS: Mr. Chairman, at this time I would move that the direct testimony of Mr. Snider be copied into the record as if given orally from the stand.

CHAIRMAN FINLEY: Mr. Snider's direct testimony filed February 21, 2017, consisting of 40 pages is copied into the record as if given orally from the stand and as revised by him from the stand.

MS. FENTRESS: Thank you.

(WHEREUPON, the prefiled direct testimony of **GLEN A. SNIDER** is copied into the record as if given orally from the stand.)

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Feb 21 2017

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

| | | |
|---|---|---|
| In the Matter of<br>Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities | )<br>)<br>)<br>)<br>) | **DIRECT TESTIMONY OF GLEN A. SNIDER ON BEHALF OF DUKE ENERGY CAROLINAS, LLC 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. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

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

**Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DEC AND DEP.**

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"). 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. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.**

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

A. The purpose of my testimony is to support the Companies' proposed avoided cost energy and capacity rate calculations and the underlying methodology used to develop those rates. My testimony will provide an overview of the rates filed in this proceeding, as well as a comparison of the rates filed in the previous two avoided cost dockets, Docket Nos. E-100, Sub 140 ("Sub 140") and E-100, Sub 136 ('Sub 136"), respectively. Furthermore, I will describe several market developments that have occurred since the recent Sub 140 proceeding, including changes in the underlying natural gas and coal commodity markets, overall changes that have occurred in the amount of Public Utility Regulatory Policy Act ("PURPA")-driven solar development within North Carolina and subsequent changes in resource planning parameters. I also provide support for the calculation of the current $2.9

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Feb 21 2017

billion total financial obligation associated with installed solar qualifying facility ("QF") power purchase agreements ("PPA") as of December 31, 2016. In relation to this financial obligation, I will explain how changing economic and market conditions have caused a potential long-term overpayment of approximately $1.0 billion by customers compared to the Companies' current calculation of its avoided cost rates proposed in this proceeding. Finally, I will address why it is essential for the Commission to recognize these changing economic and market conditions to ensure the central "but for" principle in PURPA – that avoided costs should reflect the costs of energy and capacity that would have otherwise been incurred by a utility *but for* the purchase from a QF – is upheld so residents, businesses, and industries in North Carolina do not pay more for future QF power than they otherwise would if that power was delivered from traditional resources.[1]

**Q. PLEASE EXPLAIN WHAT YOU MEAN BY FUTURE QF POWER.**

A. As recognized by Witness Kendal C. Bowman, as of December 31, 2016, approximately 1,600 MWs of utility-scale QF solar generators are now interconnected and delivering power to the Companies under prior Commission-approved avoided cost rates. An additional approximately 1,100 MWs of proposed solar QFs that are in development or under construction have also taken the steps required to "lock in" to the Sub 136 and Sub 140 standard avoided cost rates that the Commission previously approved two to

[1] *See* 16 U.S.C. 824a-3(b) and (d) (describing that the rates paid to QFs under PURPA should be based upon the utility's "incremental cost of alternative electric energy" which "***but for*** the purchase from [the QF], such utility would generate or purchase from another source.") (emphasis added).

four years ago. Thus, when I refer to future QF purchases, I want to be clear that I am referring to QFs that are in the development process, but not eligible for a previously approved rate and as such, will be subject to the final standard avoided cost rates approved in this docket.

**Q. PLEASE SUMMARIZE THE RECOMMENDATIONS THAT YOU ARE MAKING TO THE COMMISSION.**

A. As introduced in the Companies' November 15, 2016, Joint Initial Statement and discussed in greater detail in my testimony, I make the following recommendations with respect to the calculation of the Companies' avoided energy and capacity costs used in the development of DEC's and DEP's 2016 Schedule PP for DEC and PP-3 for DEP ("Schedule PP") standard offer avoided cost tariff rates:

- Include a variable 2-year rate offering and a single long-term 10-year rate offering;
- Modify the 10-year rate offering to include a Commission-approved recalculation of the energy payment every 2 years while maintaining a 10-year levelized capacity payment;
- Recognize the Companies' near term lack of capacity needs by including $0 capacity value in the capacity payment calculation until the first year that the Companies show an actual capacity need; and
- Reduce the performance adjustment factor ("PAF") from 1.20 to 1.05 to more appropriately align capacity payments to QFs under the

peaker methodology with the availability of the avoided capacity resource, which is a combustion turbine ("CT").

As discussed by Witness Bowman in her testimony, DEC's and DEP's Schedules PP-H reflect the continuation of a previously approved Stipulation of Settlement between the Companies and the NC Hydro Group; therefore, they are not the focus of my testimony. My specific recommendations herein, however, are designed to improve the accuracy and equity in the avoided cost calculation process, and are intended to align the costs customers pay for future QF energy and capacity with the avoided cost benefits created by such purchases. In doing so, the Companies' objective, consistent with PURPA, is to make our customers indifferent between purchasing QF power and traditional power.

## I. OVERVIEW OF AVOIDED COST METHODOLOGY AND STANDARD OFFER

**Q. PLEASE PROVIDE AN OVERVIEW OF THE METHODOLOGY USED TO CALCULATE THE COMPANIES' AVOIDED COST RATES, AS FILED IN THIS PROCEEDING.**

A. As explained in Section IV of the Companies' Joint Initial Statement, DEC and DEP continue to use the peaker methodology to determine standard offer avoided cost rates in this proceeding. These rates consist of energy costs which represent the fuel and other variable costs which would have been incurred but for the purchase from a QF. In addition, the seasonal capacity rates are intended to represent capacity costs deferred by the utility calculated using the fixed costs associated with a new CT. A more detailed discussion of the capacity rates and the inherent issues with attributing "capacity value" to solar QFs is discussed later in my testimony.

**Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANIES' PROPOSED STANDARD OFFER SCHEDULE PP AND PP-H RATES.**

A. DEC and DEP have filed separate rate structures and terms on Schedules PP, for non-hydroelectric facilities and on Schedule PP-H for hydroelectric facilities with no storage. Although Schedule PP incorporates certain modifications, which I discuss in more detail below, both Schedules PP and PP-H continue to include on- and off-peak energy rates, monthly seasonal capacity rates, two peak definition options, and rates designed for both distribution or transmission system level connections.

While continuing to offer a variable rate option that is updated with each biennial filing, the proposed rate Schedule PP narrows the fixed rate option to a single long-term 10-year offering. The currently filed 10-year offering includes on-peak and off-peak energy rates based on the same Option A and Option B peak hour definitions most recently approved in Sub 140. The energy rates will be re-established every two years in future avoided cost proceedings based upon the Companies' then-current avoided costs, as approved by the Commission. The associated capacity rates are based on a 10-year fixed rate that recognizes capacity value starting in the first year that the Companies demonstrate an actual need for capacity; the Companies pay, however, a levelized capacity rate in each year of the contract. The avoided capacity rate also incorporates a PAF of 1.05 based on the proven reliability of a CT. The proposed Schedule PP eliminates the 5- and 15-year standard contract terms and the proposed threshold for standard contracts is capped at 1 MW.

Figure 1 below presents the proposed rates for non-hydroelectric facilities (Schedule PP) and hydroelectric facilities with no storage (Schedule PP-H) connected to the DEC and DEP distribution systems. Figure 2 shows the individual peak definitions of Options A and B for each Company.

## Figure 1: 2016 Avoided Energy and Capacity Rates

| DEC AND DEP FILED ENERGY AND CAPACITY RATES | | | | | |
|---|---|---|---|---|---|
| | | OTHER (PP)[Note 1] | | HYDRO - NO STORAGE (PP_H) | |
| **Duke Energy Carolinas** | | Option A | Option B | Option A | Option B |
| **Variable rates** (Cents/KWH) | | | | | |
| Energy Credit | On-Peak | 3.58 | 3.59 | 3.58 | 3.59 |
| | Off-Peak | 2.98 | 3.16 | 2.98 | 3.16 |
| Capacity Credit | On-peak/Summer Month | 0.00 | 0.00 | 4.27 | 3.48 |
| | Off-peak/Non-Summer Month | 0.00 | 0.00 | 0.00 | 8.08 |
| **5 Year Fixed Long Term Rate (Cents/KWH)** | | | | | |
| Energy Credit | On-Peak | N/A | N/A | 3.62 | 3.74 |
| | Off-Peak | | | 3.17 | 3.27 |
| Capacity Credit | On-peak/Summer Month | | | 4.42 | 3.60 |
| | Off-peak/Non-Summer Month | | | 0 | 8.36 |
| **10 Year Fixed Long Term Rate (Cents/KWH)** | | | | | |
| Energy Credit | On-Peak | 3.58 | 3.59 | 3.88 | 4.06 |
| | Off-Peak | 2.98 | 3.16 | 3.26 | 3.42 |
| Capacity Credit | On-peak/Summer Month | 0.85 | 0.69 | 4.66 | 3.80 |
| | Off-peak/Non-Summer Month | 0.00 | 1.61 | 0.00 | 8.82 |
| **15 Year Fixed Long Term Rate (Cents/KWH)** | | | | | |
| Energy Credit | On-Peak | N/A | N/A | 4.34 | 4.59 |
| | Off-Peak | | | 3.44 | 3.66 |
| Capacity Credit | On-peak/Summer Month | | | 4.89 | 3.98 |
| | Off-peak/Non-Summer Month | | | 0.00 | 9.25 |
| | | OTHER (PP-3)[Note 1] | | HYDRO - NO STORAGE (PP-H-1) | |
| **Duke Energy Progress** | | Option A | Option B | Option A | Option B |
| **Variable rates** (Cents/KWH) | | | | | |
| Energy Credit | On-Peak | 3.54 | 3.63 | 3.54 | 3.63 |
| | Off-Peak | 3.25 | 3.28 | 3.25 | 3.28 |
| Capacity Credit | On-peak/Summer Month | 0.00 | 0.00 | 2.15 | 3.23 |
| | Off-peak/Non-Summer Month | 0.00 | 0.00 | 4.36 | 7.50 |
| **5 Year Fixed Long Term Rate (Cents/KWH)** | | | | | |
| Energy Credit | On-Peak | N/A | N/A | 3.47 | 3.47 |
| | Off-Peak | | | 3.14 | 3.21 |
| Capacity Credit | On-peak/Summer Month | | | 2.22 | 3.34 |
| | Off-peak/Non-Summer Month | | | 4.52 | 7.76 |
| **10 Year Fixed Long Term Rate (Cents/KWH)** | | | | | |
| Energy Credit | On-Peak | 3.54 | 3.63 | 3.60 | 3.58 |
| | Off-Peak | 3.25 | 3.28 | 3.28 | 3.34 |
| Capacity Credit | Summer Month | 0.55 | 0.83 | 2.34 | 3.53 |
| | Non-Summer Month | 1.12 | 1.93 | 4.76 | 8.19 |
| **15 Year Fixed Long Term Rate (Cents/KWH)** | | | | | |
| Energy Credit | On-Peak | N/A | N/A | 3.92 | 3.92 |
| | Off-Peak | | | 3.55 | 3.62 |
| Capacity Credit | Summer Month | | | 2.46 | 3.70 |
| | Non-Summer Month | | | 5.00 | 8.59 |

(1) The 10-year energy rates would be reestablished every two years in future avoided cost proceedings throughout the term.

## Figure 2: 2016 Rate Design Options – On- and Off-Peak Hours

| ON-PEAK AND OFF-PEAK HOURS DEFINITIONS | | | | |
|---|---|---|---|---|
| Company | Duke Energy Carolinas - Option A | | Duke Energy Carolinas - Option B | |
| | On-Peak Months<br>June through September and December through March | Off-Peak Months<br>April, May, October and November | Summer Months<br>June through September | Non-Summer Months<br>October through May |
| On-peak Hours | 7:00 a.m. to 11:00 p.m. | | 1:00 p.m. to 9:00 p.m. | 6:00 a.m. to 1:00 p.m. |
| | Monday through Friday | | Monday through Friday, excluding holidays considered as off-peak | |
| Off-peak Hours | All hours not specified as on-peak hours | | All hours not specified as on-peak hours (1) | |
| Company | Duke Energy Progress -Option A | | Duke Energy Progress -Option B | |
| | Summer Months<br>April through September | Non-Summer Months<br>October through March | Summer Months<br>June through September | Non-Summer Months<br>October through May |
| On-peak Hours | 10:00 a.m. to 10:00 p.m. | 6:00 a.m. to 1:00 p.m. and 4:00 p.m. to 9:00 p.m. | 1:00 p.m. to 9:00 p.m. | 6:00 a.m. to 1:00 p.m. |
| | Monday through Friday, excluding holidays considered as off-peak | | Monday through Friday, excluding holidays considered as off-peak | |
| Off-peak Hours | All hours not specified as on-peak hours (2) | | All hours not specified as on-peak hours (2) | |

(1) DEC All hours for the following holidays will be considered as off-peak: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and the day after, and Christmas Day.

(2) DEP All hours for the following holidays will be considered as off-peak: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and the day after, and Christmas Day. When one of the above holidays 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. HOW DO THE CURRENTLY FILED 10-YEAR RATES COMPARE TO THE PREVIOUS 10-YEAR RATES APPROVED IN SUB 140 AND SUB 136?**

A. Figure 3 and Figure 4 reflect DEC's and DEP's non-hydroelectric distribution-connected rates for a 10-year term, as shown in the Companies' Joint Initial Statement as compared to the historic rates from the Sub 140 and Sub 136 proceedings. These Figures show that the 2016 proposed annualized rates – based upon current forecasts of avoided costs – are approximately 30% lower than the prior 2014 biennial rates approved in Sub 140, which are approximately 7% lower than the prior 2012 biennial rates approved in Sub 136.

## Figure 3: DEC Historical Avoided Energy and Capacity Cost Comparison

| DUKE ENERGY CAROLINAS, LLC | | | | | | | |
|---|---|---|---|---|---|---|---|
| Distribution Interconnection | | Option A | | | Option B | | |
| | Docket | E-100, Sub 148 | E-100, Sub 140 | E-100, Sub 136 | E-100, Sub 148 | E-100, Sub 140 | E-100, Sub 136 |
| | YEAR | Filed 2016 | 2014 | 2012 | Filed 2016 | 2014 | 2012 |
| 10 Year Fixed Long Term Rate (Cents/KWH) | | | | | | | |
| Energy Credit | On-Peak | 3.58 | 4.87 | 5.28 | 3.59 | 5.04 | 5.59 |
| | Off-Peak | 2.98 | 3.79 | 4.25 | 3.16 | 4.09 | 4.51 |
| Capacity Credit | Summer Month | 0.85 | 2.19 | 2.24 | 0.69 | 6.68 | 7.92 |
| | Non-Summer Month | 0.00 | 1.09 | 0.44 | 1.61 | 2.58 | 1.22 |
| | **Annualized Energy** | **3.25** | **4.29** | **4.74** | **3.25** | **4.29** | **4.74** |
| | **Annualized Capacity** | **0.27** | **0.86** | **0.78** | **0.27** | **0.86** | **0.78** |
| | **Annualized Total** | **3.52** | **5.15** | **5.52** | **3.52** | **5.15** | **5.52** |
| **Change From Prior Filing** | | | | | | | |
| | Annualized Energy | -24% | -9% | | -24% | -9% | |
| | Annualized Capacity | -69% | 10% | | -69% | 10% | |
| | Annualized Total | -32% | -7% | | -32% | -7% | |

**Notes:**
2012 and 2014 capacity incorporates a PAF of 1.2 as compared to 2016 w hich uses 1.05
2012 and 2014 capacity reflects a value in all 10 years as compared to 2016 w hich reflects a value only in years w hich have a capacity need.

| Seasonal Allocation Factors | Option A | | Option B | |
|---|---|---|---|---|
| 2016 | On Peak/Off Peak Month | 100/0 | Summer/Non-Summer | 20/80 |
| 2014 | On Peak/Off Peak Month | 80/20 | Summer/Non-Summer | 60/40 |
| 2012 | On Peak/Off Peak Month | 91/9 | Summer/Non-Summer | 79/21 |

2012 and 2014 energy reflect a levelized value of 10 years of nominal on peak and off peak energy costs as compared to 2016 w hich reflects a levelized value of 2 years of nominal on peak and off peak energy costs w hich w ill be re calculated every 2 years for term of contract.

## Figure 4: DEP Historical Avoided Energy and Capacity Cost Comparison

| DUKE ENERGY PROGRESS, INC | | | | | | | |
|---|---|---|---|---|---|---|---|
| Distribution Interconnection | | Option A | | | Option B | | |
| | Docket | E-100, Sub 148 | E-100, Sub 140 | E-100, Sub 136 | E-100, Sub 148 | E-100, Sub 140 | E-100, Sub 136 |
| | YEAR | Filed 2016 | 2014 | 2012 | Filed 2016 | 2014 | 2012 |
| 10 Year Fixed Long Term Rate (Cents/KWH) | | | | | | | |
| Energy Credit | On-Peak | 3.54 | 4.71 | 4.94 | 3.63 | 4.71 | 5.08 |
| | Off-Peak | 3.25 | 4.03 | 4.27 | 3.28 | 4.15 | 4.35 |
| Capacity Credit | Summer Month | 0.55 | 4.16 | 3.14 | 0.83 | 6.27 | 5.23 |
| | Non-Summer Month | 1.12 | 1.41 | 2.49 | 1.93 | 2.43 | 3.97 |
| | **Annualized Energy** | **3.35** | **4.27** | **4.51** | **3.35** | **4.27** | **4.51** |
| | **Annualized Capacity** | **0.32** | **0.81** | **0.97** | **0.32** | **0.81** | **0.97** |
| | **Annualized Total** | **3.67** | **5.08** | **5.47** | **3.67** | **5.08** | **5.47** |
| **Change From Prior Filing** | | | | | | | |
| | Annualized Energy | -22% | -5% | | -22% | -5% | |
| | Annualized Capacity | -61% | -16% | | -61% | -16% | |
| | Annualized Total | -28% | -7% | | -28% | -7% | |

**Notes:**
2012 and 2014 capacity incorporates a PAF of 1.2 as compared to 2016 w hich uses 1.05
2012 and 2014 capacity reflects a value in all 10 years as compared to 2016 w hich reflects a value only in years w hich have a capacity need.

| Seasonal Allocation Factors | Option A | | Option B | |
|---|---|---|---|---|
| 2016 | Summer/Non-Summer | 20/80 | Summer/Non-Summer | 20/80 |
| 2014 | Summer/Non-Summer | 60/40 | Summer/Non-Summer | 60/40 |
| 2012 | Summer/Non-Summer | 38/62 | Summer/Non-Summer | 43/57 |

2012 and 2014 energy reflect a levelized value of 10 years of nominal on peak and off peak energy costs as compared to 2016 w hich reflects a levelized value of 2 years of nominal on peak and off peak energy costs w hich w ill be re calculated every 2 years for term of contract.

**Q. PLEASE INTRODUCE THE PRIMARY DRIVERS THAT HAVE CAUSED SUCH A SIGNIFICANT REDUCTION IN THE COMPANIES' CURRENT AVOIDED ENERGY AND CAPACITY COSTS COMPARED TO THE PREVIOUS RATES ESTABLISHED IN SUB 140.**

A. As I discuss in greater detail later in my testimony, the lower Schedule PP rates reflect a reduction in both the avoided energy and capacity components. The lower avoided energy rate results primarily from decreases in the projected cost of coal and natural gas, while the capacity rates decreased primarily because the Companies do not have an actual capacity need during the initial years of the 10-year contract term period. I will also discuss how the capacity value attributed to solar QF resources in the current Schedule PP rates is likely still overstated when the Companies' need for intermittent solar capacity relative to seasonal differences in solar output and system capacity requirements is taken into account.

## II. <u>FINANCIAL IMPACTS OF EXISTING PURPA CONTRACTS</u>

**Q. HAVE THE GROWING RISKS ASSOCIATED WITH LONG-TERM FINANCIAL OBLIGATIONS OF PURPA QF CONTRACTS CONTRIBUTED TO THE COMPANIES' PROPOSED MODIFICATIONS TO ITS PURPA STANDARD OFFERS IN THIS PROCEEDING?**

A. Yes. As discussed by Companies' Witnesses Yates and Bowman, the Companies believe the State is at a solar development crossroads. The recent rapidly changing economic and market circumstances, including the surging growth in long-term QF fixed price contracts, has been a primary driver of the Companies' proposed modifications to its standard offer rate structures in this proceeding. As described by Witness Bowman, the Companies' proposed modifications represent a first step in a long-term transition towards a smarter, more sustainable renewable energy future.

**Q. HAVE THE COMPANIES CALCULATED THE APPROXIMATE FINANCIAL OBLIGATION CUSTOMERS WILL PAY FOR EXISTING SOLAR QF POWER BASED ON EXISTING FIXED PRICE QF CONTRACT TERMS?**

A. Yes. Focusing only on the approximately 1,600 MWs of existing solar QF purchase power contracts for installed solar QFs of 1 MW and greater as of year-end 2016, the estimated future obligation for capacity and energy payments to solar QFs is approximately $2.9 billion dollars over the remaining terms of these agreements (the majority of which continue for the next approximately 12 to 14 years).

**Q. RELATIVE TO THE TOTAL SOLAR PURCHASED POWER OBLIGATION PREVIOUSLY MENTIONED, WHAT IS THE CURRENT EXPECTED AVOIDED COST VALUE THAT THESE PURCHASE OBLIGATIONS WILL PRODUCE FOR THE CITIZENS AND BUSINESSES OF NORTH CAROLINA?**

A. As mentioned, DEC's and DEP's current estimated combined financial obligation for previously contracted solar QFs as of December 31, 2016, is approximately $2.9 billion, which ultimately will be paid for by our customers. If those contracts were valued at the most recently filed avoided cost rates, they would have a value of only $1.9 billion. This results in a gap of approximately $1.0 billion, representing the level of potential overpayment by customers as compared to the Companies' current proposed avoided cost rates filed in this proceeding.

**Q. TO THE EXTENT THE OBLIGATION AND OVERPAYMENT EXPOSURE PREVIOUSLY MENTIONED INCLUDES ONLY PPAS FOR INSTALLED SOLAR QFS AS OF DECEMBER 31, 2016, IS THERE ADDITIONAL FINANCIAL EXPOSURE FROM INCREMENTAL SOLAR OBLIGATIONS UNDER SUB 136 AND SUB 140 RATES THAT COULD COME ONLINE AFTER 2016?**

A. Yes. This is another critical point for the Commission to appreciate. As described in Witness Bowman's testimony, there are approximately 4,900 MWs of solar projects in the Companies' combined North Carolina interconnection queues, including approximately 1,100 MWs of solar QF projects under 5 MWs that have established Sub 136 or Sub 140 legally enforceable obligations ("LEOs"), making them eligible for the previously approved avoided cost rates. Development of these additional solar QFs under the now-stale and significantly higher Sub 136 or Sub 140 rates inevitably means that the Companies' and our customers' current financial obligation and exposure to overpayment risk could increase significantly in the future.

## III. PROPOSED MODIFICATIONS TO AVOIDED ENERGY RATES

**Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE METHOD BY WHICH ON- AND OFF-PEAK ENERGY VALUES ARE CALCULATED.**

A. Peak energy values are calculated through the use of the peaker methodology. The peaker methodology approximates a utility's avoided energy cost through estimates produced by generation production cost modeling. In terms of energy, this approach assumes that when a utility's generating system is operating at equilibrium, the variable marginal energy costs of running the system will produce the marginal energy cost that the utility avoids by purchasing power from a QF.

Avoided energy costs represent an estimate of the variable costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. Avoided energy costs, which are expressed in dollars per megawatt-hour ("$/MWh"), include items such as avoided fuel and avoided variable operating and maintenance ("VOM") expenses.

In any given hour, the Companies will have a variety of units online such as existing renewable resources, hydro, nuclear, natural gas combined cycle, coal, natural gas simple cycle CTs, and diesel fuel oil CT resources. These units all have differing fuel and variable operating costs that are largely dispatched on an economic basis to meet instantaneous load obligations. The peaker methodology credits the QF for avoiding energy, more specifically fuel and VOM costs, from the most expensive unit, which is often referred to as the marginal unit.

**Q. WHAT IS THE PRIMARY DRIVER OF THE COMPANIES' MARGINAL COST OF GENERATION THAT CAN BE AVOIDED THROUGH QF PURCHASES?**

A. While items such as VOM costs, environmental reagent costs, and the relative efficiency of the marginal unit all factor into the marginal cost of generation, the cost of the underlying coal, natural gas or fuel oil is the primary driver of the energy cost of the marginal unit.

**Q. WITH RESPECT TO FUEL PRICES, PLEASE ADDRESS THE SIGNIFICANT MARKET CHANGES THAT HAVE OCCURRED SINCE THE PREVIOUS SUB 136 AND SUB 140 AVOIDED COST DOCKETS**

A. In general, 10-year (2017 to 2026) levelized natural gas prices have fallen approximately 40%, while coal prices have fallen approximately 16% for that same time period as compared to those used in calculating the Companies' avoided cost of energy in the 2014 biennial Sub 140 proceeding. Compared to the 2012 Sub 136 avoided energy costs, fuel costs have fallen even further with natural gas declining approximately 48% and coal, 33%.

**Q. OTHER THAN THE RISK OF FALLING FUEL PRICES, ARE THERE ANY STRUCTURAL RISKS BORNE BY CONSUMERS ASSOCIATED WITH THE PREVIOUS 15-YEAR FIXED PRICE RATES THAT WERE HELD CONSTANT WITHOUT ADJUSTING FOR CHANGES IN MARKET CONDITIONS?**

A. Yes, there are. The prior avoided cost structure offered 15-year fixed price rates that were then left unchanged for 2 years between rate filings effectively creating "stale" rates. This created a systematic bias for consumers to overpay for the power delivered from those QF contracts irrespective of commodity prices moving up or down. Simply stated, the QF under the prior construct, at its sole discretion, could opt to sell (or "put") power to the consumer at the old published standard offer rate if they observed market prices declining. Conversely, if market prices were rising the QF could either wait for a new rate to be published or upsize its project and ask the Companies for a negotiated rate commensurate with the higher prevailing commodity prices.

By way of example, this "free option" was exercised by approximately 350 MWs of QF projects who established LEOs to sell power to DEP and DEC in October 2016, just prior to the expiration of the Sub 140 rates. These QFs clearly observed commodity prices falling dramatically over the last two years and had the full knowledge that current avoided cost rates would be below those filed in Sub 140. However, if commodity prices had been moving in the opposite direction the QF could have simply waited a month and established a 15-year fixed price at a higher rate. As a result of this free option, the consumer systematically pays above the true prevailing "but for" avoided cost envisioned under PURPA.

**Q. PLEASE EXPLAIN WHY THE COMPANIES HAVE SHIFTED TO A 10-YEAR RATE OFFERING WITH ENERGY RATES THAT ARE ADJUSTED EVERY TWO YEARS?**

A. As described above, entering into long-term fixed price contracts without regard to changing market conditions has caused the citizens and businesses of North Carolina to pay for QF generation at a substantially higher cost. However, if energy rates were recalculated on a more regular basis, they would better align with future fuel commodity prices. Because the overpayment in energy rates to the QFs is driven primarily by the significant decline in fuel commodity prices over the last several years as well as the structural biases discussed above. Not recalculating energy rates for a shorter term and on a more regular basis results in solar QFs being paid more than their avoided energy value justifies. A structure that adjusts the energy rates at reasonable, periodic intervals throughout the duration of a long-term contract is an effective way to reduce customers' exposure to overpayments. This structure ensures that the value of the QF power aligns with the price consumers are paying for that power adhering to the "but for" principle of PURPA.

Under the prior methodology approved in Sub 140, long-term fixed avoided cost rates were based on fuel commodity prices forecasted 10 and 15 years into the future. These rates were then left "stale" for two years leaving customers to bear significant risk of overpayment if projections of prices were too high. Based on our review of current and past commodity prices, that risk of overpayment has become a reality for our customers. To mitigate the potential harm to our customers of long-term overpayments in excess of the Companies' actual avoided energy costs, the Companies have modified their proposed standard offers to balance the QF's interest for longer-term contracts while also limiting the significant fuel commodity forecast price risk for our customers going forward. Furthermore, this rate structure significantly reduces the structural risk previously described by removing the free option for QFs to choose the "higher of" a 15-year price from 2 years ago or a 15-year price at current conditions. In summary, the current rate structure is a more equitable structure for both the consumer and the QF power provider that better controls costs and aligns consumer value with QF payments.

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**Q. DO PURCHASED POWER CONTRACTS THAT THE COMPANY ENTERS INTO OUTSIDE OF PURPA HAVE LONG-TERM COMMODITY PRICE RISK ASSOCIATED WITH THEM?**

A. Generally, they do not. First, the Companies seek to procure energy or build new generation based on a need that is typically defined in the Companies' IRP. Second, when the Company solicits offers for new energy or capacity, the Commission reviews the prudence of the Companies' proposed resource option by assessing the economics and risks with the objective of procuring the least cost, least risk assets for customers. In terms of new generation, the Company typically achieves this through RFP and competitive bidding supply-chain processes which normally seek to procure the least cost alternative. Finally, when contracts are negotiated to purchase power, outside of PURPA, the energy payment terms are generally linked to a real time fuel price index, and as such, the Companies minimize the risk of the customer paying beyond market energy prices for this power. Thus, the Companies' proposed modification to the standard offer contract structure better aligns the level of risk imposed upon customers in PURPA contracts with non-PURPA contracts.

**Q. HOW DOES PURCHASED QF POWER COMPARE TO THE COMPANIES' FUEL HEDGING PRACTICES?**

A. There are both similarities and differences when comparing QF purchases under PURPA rates to fuel hedging. On the similarity side, the purchase of fixed price power over a period of time can be achieved by purchasing the power directly, as in the case of QF purchases. In a similar fashion, the price of power can be fixed by hedging purchases of natural gas or coal for the Companies' fossil generation units at a fixed price for a period of time into the future. Both practices fix the price of power into the future. It should be noted that the company hedges only a portion of its projected natural gas needs on a rolling 3-year basis thereby avoiding 15-year fixed price obligations. This shorter duration limits differences between the ultimate prevailing spot price and the original hedge price while lowering the volatility of natural gas prices for the consumer. However, on the difference side when the company hedges fuel it does so at the prevailing market price on the day and hour it entered into the purchase. These purchases reflect the future market prices for natural gas that change on not only a daily basis but on an hour to hour and even minute-to-minute basis. Furthermore, natural gas hedging takes place across time and across business cycles without a bias toward purchasing higher price natural gas while avoiding purchasing when prices are lower. As described above this is not the case with PURPA QFs that have a systematic bias to sell to customers at the higher of existing "stale" long-term rates, negotiated long-term rates or to simply wait for new long-term rates in a rising commodity price environment.

**Q. IN ADDITION TO PREVIOUSLY DISCUSSED ADJUSTMENTS, HAVE THE COMPANIES INCLUDED A REDUCTION IN THE ENERGY RATE TO COMPENSATE FOR THE ADDITIONAL GENERATION ANCILLARY SERVICE COSTS ASSOCIATED WITH INCREASED, NON-CONTROLLABLE SOLAR GENERATION?**

A. Not at this time. Integration costs were a significant issue in the recent Sub 140 proceeding, and the Commission's December 31, 2014 Order recognized that costs and benefits related specifically to integration of solar QFs could appropriately be taken into account in deriving the costs avoided by solar QF resources. At this time, however, the Companies have not included incremental ancillary service costs driven by solar generation in the standard offer Schedule PP avoided cost rates, as these standard offer rates are proposed to be eligible only for smaller QFs 1 MW and under. Depending on the future adoption rate of non-controllable QF solar and the Companies' further analysis of the costs and potential benefits of integrating these small solar generators onto their systems, it may be necessary to address the ancillary services costs in future standard offer avoided costs filings. Furthermore, in the context of larger negotiated QFs, the Companies believe it is appropriate to address the costs of ancillary services and other potential integration costs that relate to the specific characteristics of these QF generators.

## IV. SOLAR IMPACTS ON PLANNING AND RELIABILITY

**Q. PLEASE BRIEFLY SUMMARIZE THE RESULTS OF THE 2016 RESOURCE ADEQUACY STUDIES THAT WERE INCLUDED IN DEVELOPMENT OF THE 2016 IRP FILING.**

A. The Companies commissioned new resource adequacy studies that were finalized in 2016. The results of the studies were presented in the 2016 IRPs. The new studies were conducted as a result of the high penetration of solar resources that have been connected to the Companies' transmission and distribution systems in the past two-three years, as well as the high volume of solar resources currently in the interconnection queues. The other primary driver for the new studies was to account for the significant load response to cold weather that was experienced during the 2014 and 2015 winter periods. Based on results of the studies, the Companies have shifted from summer to winter capacity planning and adopted a 17% minimum winter reserve margin target.

**Q. PLEASE EXPLAIN WHAT YOU MEAN BY THE SHIFT TO WINTER CAPACITY PLANNING.**

A. In the past, the Companies' annual peak demands were projected to occur in the summer. Additionally, the Companies' generating fleets have greater output during winter periods compared to summer periods, particularly for gas-fired CT and combined-cycle units. As a result, on a projected basis, the Companies' summer reserves have historically been lower than winter reserves and loss of load risk has been greater in the summer than in the winter. Thus, summer load and resources have driven the timing need for new resource additions, and a summer reserve margin target provided adequate reserves in both the summer and winter periods and was sufficient for ensuring overall resource adequacy.

The load and resource balance has changed drastically in the past two-three years, driven primarily by the high penetration of solar resources and the significant load response to cold weather experienced during the 2014 and 2015 winter periods. As discussed in more detail later in my testimony, solar resources contribute significantly more to the summer afternoon peak than they contribute to the winter morning peak. As such, the 2016 resource adequacy studies demonstrated that the loss of load risk is now heavily concentrated during the winter period. Thus, a summer reserve margin target will no longer ensure adequate reserve capacity in the winter, and winter load and resources now drive the timing need for new capacity additions. The transition to winter capacity planning will ensure that adequate reserves will be available throughout the year to ensure resource adequacy.

**Q. DID THE COMPANIES INCREASE THEIR MINIMUM PLANNING RESERVE MARGIN TARGET IN THE 2016 IRP?**

A. Yes, they did. The results of the 2016 resource adequacy studies showed that the combination of high solar penetration and significant winter load response resulted in not only a shift to winter capacity planning, but also an increase in the minimum planning reserve margin to ensure adequate generation system reliability. The Companies now plan their systems to maintain a minimum 17% winter reserve margin.

**Q. DID THE INCREASING AMOUNTS OF SOLAR CAPACITY IMPACT THE OPERATING RESERVES ASSUMPTIONS IN THE 2016 RESOURCE ADEQUACY STUDIES?**

A. No. The resource adequacy studies were focused on longer term planning reserve margins driven by loss of load probability assessments as opposed to an ancillary service study that would focus on the need for shorter term real time operating reserve requirements. The resource adequacy studies utilized hourly simulations but did not take into account loss of load or curtailment of renewable generation due to insufficient real time system operating reserve capabilities. The resource adequacy studies recognized that for grid stability purposes, load would be shed in order to maintain the minimum generation regulation requirements of the systems. The need for operating reserves required due to high solar penetration was not modeled in the studies. If the amount of operating reserves protected by firm load shed were to increase due to the ancillary impacts of additional solar generation, then the long-term planning reserve margin target would also need to increase.

**Q. PLEASE EXPAND ON HOW ANCILLARY IMPACTS OF SOLAR GENERATION MAY INFLUENCE THE TYPES OF NEW GENERATION IN FUTURE RESOURCE PLANS.**

A. The ancillary services impact of high levels of must-take solar may need to be considered in future plans when recommending the types of resources needed to satisfy winter reserve margin requirements, and to ensure adequate system ramping capability and operational flexibility. As discussed in more detail in Witness Holeman's testimony, increasing levels of variable unscheduled and unconstrained solar QFs may create an incremental need for faster response load following generation to meet system loads when solar generation either increases or decreases rapidly. In fact, the Companies have already added or are proposing to add more flexible resources to the system, such as fast-start CTs at Sutton, runner upgrades at Bad Creek Pumped Hydro Station, dual fuel optionality at Cliffside, and the recently announced expansion at the Lincoln County CT site. While increasing levels of solar on the system may not have been the primary driver for these projects, the operational flexibility these projects provide has value given the increasing levels of solar on the system. As more non-dispatchable solar is added, additional flexible resources of all types may be required to reliably manage system operations.

## V. PROPOSED MODIFICATIONS TO THE AVOIDED CAPACITY RATES

**Q. PLEASE EXPLAIN WHAT IS MEANT BY CAPACITY VALUE AS CONTRASTED TO ENERGY VALUE.**

A. Customer demand for electricity changes moment to moment and the demand for electricity must constantly be balanced with capacity resources. For example, if the demand for electricity at the beginning of a given hour is 10,000 MWs, then the Company must have 10,000 MWs of capacity resources available to meet that demand, as well as appropriate resources available to respond to demand as it changes from hour-to-hour and minute-to-minute. As further discussed by Witness Holeman, the Company must have firm resources available to meet the demand, as well as controllable resources that can be dispatched and ramped up and down to respond to the changing demand for electricity.

Capacity value is a function of the amount of firm capacity that a generating unit is able to provide during reliability-critical periods. Stated another way, the capacity value of a generator reflects its ability to serve customer demand reliably during these periods. Thus, a resource's capacity value is based on the amount of MWs that can be counted on to provide continuous, load-carrying capability to meet customer load demands when called upon during peak conditions. The possibility of forced and planned outages impacts all resources and is considered in planning of the system. Capacity resources include baseload generating units, dispatchable generating units and firm purchases, as well as demand-side management resources that can be called upon to reduce customer load demand.

Unlike capacity value, energy value can be attributed to both intermittent resources, such as solar and wind, as well as dispatchable resources, such as natural gas and coal. In general terms, as previously discussed, these resources help the Companies meet a portion of customer energy requirements and thus have energy value by displacing the marginal cost of the next increment of generation.

**Q. PLEASE COMPARE THE ENERGY VALUE SOLAR QFS PROVIDE THRUOGHOUT THE YEAR WITH THEIR CAPABILITY TO PROVIDE CAPACITY VALUE TO HELP MEET THE COMPANIES' NOW-PREDOMINANT WINTER PEAK DEMANDS.**

A. Solar QF generation is a variable, renewable energy resource with output that depends on the time of day, season and weather patterns. Although this resource cannot be dispatched to meet peak demand conditions or changes in customer demand, it still provides a variable amount of energy to the grid during daylight hours throughout out the year and as such reduces fuel and VOM the company would otherwise incur to provide the energy that is being met by the solar resource.

In contrast to the energy value solar QFs provide throughout the year, the Companies' growing experience is that solar QF resources have very limited capacity value to help meet the Companies' systems now-predominant winter peaks. The Companies' winter peaks occur in the early morning hours around 7:00 a.m. when solar basically has little to no output. The solar capacity contribution to winter peak demand is about 5%, meaning that only about 5 MWs out of every 100 MWs of installed nameplate solar is expected to be available to meet the early morning winter peak. Although solar output increases in the mid-morning hours on clear winter days, the Companies' peak demand has typically already occurred. Further, solar QF resources cannot be dispatched to meet peak demand conditions or changes in customer demand. Since solar only contributes about 5% of its nameplate capacity at the time of the Company's winter peak, solar resources provide very little, if any, capacity value.

**Q. ARE SOLAR RESOURCES ALLOWING THE COMPANIES TO AVOID BUILDING OR BUYING CAPACITY IN FUTURE YEARS?**

A. As I stated, solar has very little capacity value since little to no solar output is available at 7:00 a.m. on cold winter mornings when the Companies realize their peak demands. Thus, solar has no significant impact on avoiding future resource needs that are now driven by maintaining a minimum winter reserve margin target. This is evidenced by the fact that even though more and more solar is being connected to the Companies' transmission and distribution systems, the Companies are only counting on 5% of nameplate solar as being available to meet winter peak demand and reserve requirements. In other words, the Companies are effectively building the same amount of generation capacity irrespective of the amount of QF solar that is added to the system, which effectively demonstrates that solar resources are not displacing or avoiding new generation capacity. Consequently solar resources are creating little capacity value for consumers.

**Q. SINCE SOLAR CAPACITY CAN BE BUILT IN SMALLER INCREMENTS AND WITH SHORTER LEAD TIMES, HAS SOLAR QF DEVELOPMENT MORE CLOSELY MATCHED THE COMPANIES' FUTURE LOAD GROWTH AND FUTURE CAPACITY NEEDS, CREATING LESS EXCESS CAPACITY?**

A. No. This presumption has been proven flawed due to the continued surging solar QF growth resulting in capacity payments to QFs that far exceed the value that they offer consumers. Further, as I have stated, the high penetration of solar is one of the key drivers responsible for the Companies' recent shift to winter capacity planning because solar does not provide meaningful contributions to the Companies' winter capacity and reserve margin needs.

**Q. WHAT IS THE IMPACT OF SURGING SOLAR QF CAPACITY ON RESERVE MARGINS?**

A. Solar resources contribute approximately 45% (46% for DEC and 44% for DEP) of their nameplate rating at the time of the summer peak, which occurs in afternoon hours. However, as discussed above, the Companies' winter peaks occur in the early morning hours around 7:00 a.m. when solar basically has no output. The Companies' 2016 IRPs reflect a 5% capacity contribution from solar for winter resource planning purposes. Thus, for every 100 MWs of nameplate solar that is constructed, approximately 45 MWs contributes to reserves at the time of the summer peak, but only about 5 MWs contributes to reserves at the time of the winter peak. Thus, as solar resources continue to grow over time, the Companies' summer reserves increase compared to winter reserves.

To illustrate, for every 1,000 MWs of nameplate solar installed, the Companies would realize approximately 450 MWs of contribution to summer peak requirements while only realizing 50 MWs of contribution to winter peak needs. Traditional resources such as gas-fired CTs contribute more evenly to reserves year-round, and actually have somewhat greater output during the colder winter periods when the air is denser. High solar penetration is one of the drivers behind the shift to winter capacity planning and why the Companies must now plan new resource additions to satisfy minimum winter reserve margin targets. Planning to a 17% winter reserve margin with growing solar penetration will result in increasing summer reserve margins over time. Thus, the disparity between summer and winter reserve margins will continue to grow as solar penetration increases. This disparity eventually levels off as the summer peak demand net of solar output moves into the evening hours.

**Q. HOW DOES THE SEASONAL SHIFT FROM SUMMER TO WINTER CAPACITY PLANNING IMPACT THE CAPACITY VALUE OF SOLAR WITHIN THE CONTEXT OF THE COMPANIES' AVOIDED COST RATES?**

A. The 2016 resource adequacy studies showed that approximately 80% or more of the loss of load risk now occurs during the winter period and about 20% during the summer period. The 80/20 winter/summer seasonal weighting was incorporated in the calculation of the Companies' avoided cost rates in this Docket.

**Q. DO THE AVOIDED CAPACITY RATES FILED IN THIS DOCKET ACCURATELY REFLECT THE CAPACITY VALUE OF SOLAR REPRESENTED IN THE COMPANIES' IRPS?**

A. No, they do not. In fact, the Companies' recently filed rates still tend to overcompensate for the capacity value of solar due to the broad on-peak hour definitions under Options A and B of Schedule PP. As such, solar resources will be compensated for levels of capacity that will not actually be avoided.

**Q. IF IN THE IRP, SOLAR PROVIDES A 5% CAPACITY VALUE RELATIVE TO ITS NAMEPLATE RATING, TO WHAT EXTENT ARE THE COMPANIES' PROPOSED AVOIDED CAPACITY RATES DESIGNED TO COMPENSATE FOR THE NAMEPLATE CAPACITY?**

A. Given the broad definition of on-peak hours in the current rate structure, under Option B of Schedule PP, a typical solar facility would be compensated for avoiding approximately 40% of its nameplate capacity in equivalent avoided "peaker" capacity while only providing an actual capacity value of about 5%. This means that each MW of QF solar would be compensated for almost 40% of the cost of a MW of a CT beginning with the first need for new capacity while providing only 5% of the capacity value that a CT would provide.

**Q. DO THE COMPANIES PLAN TO ADDRESS THIS OVERVALUATION OF QF CAPACITY IN DESIGNING FUTURE STANDARD OFFER TARIFFS?**

A. Yes. The Companies' current Schedule PP standard offer maintains the preexisting Option A and Option B hours and rate structure most recently approved in Sub 140. However, because this rate structure is increasingly providing a subsidy to the small QFs eligible for the Schedule PP by overvaluing their capacity avoidance during the Companies' winter peak hours, the Companies believe it is important to reconcile these differences going forward. Thus, the Companies plan to consider the appropriateness of their current on-peak hour and seasonal definitions further and propose modifications to the current rate structure both in the rates that are negotiated with larger QFs and in the next biennial avoided cost filing. While the Companies have not proposed to modify the Option A and Option B hours and rate structure in this proceeding, I would highlight that reducing the standard offer in this proceeding to QFs 1 MW and under will allow the Companies to better align their avoided cost rate payments with the actual capacity value being created by the QFs greater than 1 MW.

**Q. NOW PLEASE ADDRESS THE CHANGES TO THE CALCULATION OF THE AVOIDED CAPACITY COST PAYMENT THAT THE COMPANIES HAVE MADE IN THIS PROCEEDING.**

A. The Companies' relative need for incremental generating capacity should be taken into account in calculating its avoided capacity rates. In particular, the calculation of the capacity portion of the avoided cost rate should not ascribe value for years prior to the first avoidable capacity need. This simply means that the capacity rate received by the QF would reflect a lower annual levelized payment to account for the initial years in which no avoidable capacity costs would be included in the rate derivation.

**Q. UNDER THE PRIOR SUB 140 AVOIDED CAPACITY COST CALCULATION METHODOLOGY, ARE THE UTILITIES' RELATIVE NEED FOR INCREMENTAL GENERATING CAPACITY TAKEN INTO ACCOUNT?**

A. No. The methodology, as applied under the Sub 140 standard tariff, required calculations of avoided capacity rates to include a cost for capacity even in those years where the Companies' IRPs do not show a corresponding need for capacity.

**Q. PLEASE EXPLAIN HOW THE NEED FOR CAPACITY SHOULD BE ACCOUNTED FOR IN CALCULATING AVOIDED CAPACITY PAYMENTS.**

A. Under PURPA, utilities should not require their customers to pay for QF capacity unless there is an associated capacity cost to be avoided. Without modification, the current approach violates this "but for" principle and results in the Companies' customers paying for QF capacity that does not offset needed utility capacity. As a result, retail customers are paying avoided costs for capacity the Companies do not need – in excess of the Companies' avoided capacity cost, as determined under the peaker methodology.

**Q. HOW DO YOU RECOMMEND THE RELATIVE NEED FOR INCREMENTAL GENERATING CAPACITY BE INCLUDED IN THE CALCULATION OF THE AVOIDED CAPACITY PAYMENT?**

A. Avoided capacity costs are represented on an annual basis in a similar fashion to the fixed cost of a car or home being represented as an annual car payment or mortgage payment. To appropriately incorporate the need for capacity consistent with PURPA, the annual fixed capacity costs that go into the avoided cost rate should include only the annual fixed capacity costs for years in which an actual capacity need exists as determined by the utilities' most recently filed IRPs.

**Q. HOW IS THE IRP UTILIZED TO DETERMINE WHEN DEC AND DEP HAVE AN AVOIDABLE CAPACITY NEED?**

A. The IRP presents a 15-year resource plan that identifies when the next generation unit is needed for reliability purposes. Prior to the year in which the next 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 rate should not ascribe value for years prior to the first avoidable capacity need.

**Q. DO THE COMPANIES HAVE A NEAR TERM CAPACITY NEED BASED ON THEIR 2016 IRPS?**

A. No. As I noted earlier, the first capacity need for both Companies occurs in the 2022-2023 timeframe.

**Q. DOES ACCOUNTING FOR THE TIMING OF NEEDED CAPACITY MORE ACCURATELY AND APPROPRIATELY VALUE THE "ALTERNATIVE ENERGY AND CAPACITY" BEING DELIVERED BY THE QF, CONSISTENT WITH THE INTENT OF PURPA?**

A. Yes. PURPA's clear intent is to estimate costs that, but for purchase from the QF, would have otherwise been incurred by the utility and its customers. This PURPA principle requires the recognition that if the utility's first avoidable capacity need is several years into the future, then the present avoided capacity rate should only reflect the value in that future period when there is a capacity need to avoid.

**Q. DOES THIS IMPLY THAT QFS UNDER THE TARIFF RECEIVE NO CAPACITY PAYMENT IN YEARS PRIOR TO THE COMPANIES' FIRST CAPACITY NEED?**

A. No. This simply implies the capacity rate received by the QF would reflect a lower annual payment to account for the initial years in which no avoidable capacity costs would be included in the rate derivation. In essence, the QF will receive capacity payments immediately in recognition of future avoided capacity so long as the utility has an avoidable capacity need sometime within the life of the tariff period.

**Q. IS THE CONSIDERATION OF THE NEED FOR CAPACITY IN THIS CALCULATION FAIR TO THE COMPANIES' CUSTOMERS?**

A. Yes. With the adjustments suggested, the utilities' customers would only be paying QF capacity payments equal to the economic value of an associated avoided utility capacity cost.

**Q. ARE YOU RECOMMENDING ANY CHANGES TO THE PAF FOR QFS OTHER THAN RUN-OF-RIVER HYDRO FACILITIES?**

A. Yes. The Companies request that the PAF for QFs other than hydroelectric facilities with no storage should be reduced from 1.20 to 1.05 to align the multiplier with the reliability of a CT, which is currently the basis for establishing the avoided capacity cost using the peaker methodology.

**Q. WHAT IS THE RATIONALE FOR REDUCING THE PAF FROM 1.2 TO 1.05?**

A. The PAF was established because QFs only receive capacity payments for power that they deliver during on-peak hours. Because all generation is subject to outages, it is reasonable to assume under the peaker methodology that QFs, like other generation, will not run during 100% of on-peak hours. Thus, the PAF makes up for a QF's unavailability during a peak period by increasing the capacity rate it is paid during the peak hours that it does not operate. Currently, solar and other non-hydro QFs enjoy the benefit of a PAF of 1.20.

Given that avoided resources are occasionally unavailable, it necessarily follows that QFs replacing those resources should not be penalized for experiencing the same level of unavailability typically experienced by the resources it is displacing. That logic works, however, only if the PAF is structured to put a QF on par with the resource it is replacing.

When using the peaker methodology to calculate avoided cost rates, the resource a QF is replacing is the CT. The appropriate measure of reliability for a CT peaking unit is the starting reliability. The Companies' CT fleet performs at a greater than 95% starting reliability and as such, no PAF greater than 1.05 is warranted as it would only further exacerbate the subsidy given to smaller QFs and subject our customers to unfair, unjust, and unreasonable higher rates that exceed the costs actually being avoided.

**Q. THE COMMISSION REVIEWED A SIMILAR PROPOSAL REGARDING THE PAF IN SUB 140 AND DECLINED TO ADOPT IT. WHY SHOULD IT DO SO NOW?**

A. I am not an attorney, but as an expert witness testifying on behalf of the Companies in both Sub 136 and Sub 140, I understand that the Commission initiated Sub 140 to revisit its biennial proceeding precedents with respect to its PURPA policies.[2] After its review of the PAF issue in Sub 140, the Commission determined that the arguments to modify it were insufficient *at that time*.[3] In so concluding, the Commission noted that there had been "widespread QF development under the existing framework *without adverse*

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[2] *Order Establishing Biennial Proceeding and Scheduling Hearing*, at 56 Docket No. E-100, Sub 140 (Dec. 31, 2014).

[3] ~~*Id.*~~ (Emphasis added).
Order Setting Avoided Cost input parameters issued on December 31, 2014, in Docket number E-100, Sub140 at page 56.

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*impacts to utility ratepayers.*"[4] Since the 2014 commencement of the first phase of Sub 140, however, both DEC and DEP have experienced an unprecedented surge in solar QFs, such that our customers are presently exposed to approximately $1 billion in overpayments for energy and capacity, relative to the current market, over the next 12-14 years. Significantly, that approximate $1.0 billion only accounts for QFs that are currently energized and delivering power to DEC or DEP; it *does not* include the approximately 1,100 MW (of 5 MWs and less QFs) that are in development or under construction and remain eligible for the now-stale avoided cost rates that were calculated and approved in either Sub 140 or Sub 136.

**Q. HAVE ANY OTHER JURISDICTIONS RECENTLY REVIEWED THE USE OF A PERFORMANCE ADJUSTMENT FACTOR OR SIMILAR ADDER FOR THE CAPACITY PAYMENT MADE TO QFS UNDER THE PEAKER METHOD?**

A. To the Companies' knowledge, the only implicit recognition of a PAF-type adder in a jurisdiction that uses the peaker methodology was in the Companies' 2016 South Carolina fuel factor proceedings, which also reestablished DEC's and DEP's standard avoided cost rates. In April 2016, DEC and DEP entered into a Memorandum of Understanding ("MOU") with the South Carolina Office of Regulatory Staff and other interveners, in which the Companies agreed to adopt, for South Carolina purposes, the avoided cost rates that this Commission approved in Sub 140. The MOU does not describe

[4] *Id.* (Emphasis added).

the underlying methodology or calculations used to calculate those final rates, nor does it set a precedent as to the reasonableness of those calculations or methodology. Thus, the issue of the PAF was not squarely before the Public Service Commission of South Carolina ("PSCSC") when it approved the MOU. However, the PSCSC has also expressly rejected a proposal by an intervener in a 2016 South Carolina Electric and Gas fuel factor proceeding to include a PAF citing "it is unreasonable to employ a [PAF] to the capacity payment when there is no guarantee of performance with regard to capacity."[5] Notably, I am not recommending that the Commission abolish the PAF altogether, only that it more appropriately align the PAF to the reliability of the CT under the peaker methodology.

**Q. IS THE ADJUSTMENT TO THE PAF AND THE CONSIDERATION OF THE NEED FOR CAPACITY IN CALCULATING AVOIDED CAPACITY COST RATES FAIR TO THE COMPANIES' CUSTOMERS?**

A. Yes. With the adjustments suggested, the Companies' customers would be paying QF capacity rates that more closely approximate the presumed economic value under the peaker methodology provided by the QF.

[5] *Order Approving Fuel Costs and Adopting Settlement Agreement*, South Carolina Public Service Commission Order No. 2016-297, Docket No. 2016-2-E (April 29, 2016).

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## IV. CONCLUSION

**Q. DO THE COMPANIES' RECOMMENDATIONS RELATING TO THE CALCULATION OF AVOIDED COSTS PROVIDE FOR A MORE FAIR AND ACCURATE CALCULATION OF SUCH COSTS?**

A. Yes, they do, which is critical for our customers going forward in light of the rapid changes in the solar QF marketplace. As I noted, the Companies' proposed modifications are designed to better reflect the actual energy and capacity value being delivered by QFs to the utilities and are responsive to the unprecedented amount of solar QF power interconnected or planned to be interconnected to the Companies' systems. Implementing these recommendations will help the Commission ensure that future QF development in North Carolina will be more appropriately aligned with the actual avoided cost value being created for the residents and businesses of North Carolina. Of equal importance, the rate structure in this proceeding significantly improves the possibility that the value proposition for both QF providers and electricity consumers is better aligned. Of equal importance, the rate structure in this proceeding significantly reduces the possibility that this value proposition between QF providers and electricity consumers gets out of alignment. In this respect, the proposed modifications are entirely consistent with the "but for" principle of PURPA.

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

A. Yes. It does.

BY MS. FENTRESS:

Q And, Mr. Snider, did you cause to be prefiled in this docket on April 10th of this year 68 pages of rebuttal testimony, portions of which contained confidential information?

A (MR. SNIDER) Yes, 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 the same questions that appear in your rebuttal testimony today, would your answers be the same?

A Yes, they would.

MS. FENTRESS: Mr. Chairman, at this time I would move that the rebuttal testimony of Mr. Snider be copied into the record as if given orally from the stand --

CHAIRMAN FINLEY: Mr. Snider --

MS. FENTRESS: I'm sorry.

CHAIRMAN FINLEY: Finish.

MS. FENTRESS: And that the confidential portions of Mr. Snider's rebuttal testimony be maintained under seal.

CHAIRMAN FINLEY: Mr. Snider's rebuttal

testimony filed April 10, 2017, consisting of 68 pages is copied into the record as though given orally from the stand, and that part of his testimony marked confidential shall be so identified in the record.

MS. FENTRESS: Thank you.

(WHEREUPON, the prefiled rebuttal testimony of **GLEN A. SNIDER** is copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

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| In the Matter of<br>Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities | )<br>)<br>)<br>)<br>) | **REBUTTAL TESTIMONY OF GLEN A. SNIDER ON BEHALF OF DUKE ENERGY CAROLINAS, LLC 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. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

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

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

A. Yes. I submitted direct testimony in this proceeding on behalf of Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP"), (collectively, the "Companies") on February 21, 2017.

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

A. My rebuttal testimony is organized into the following sections.

I. General Observations and Considerations

II. Issues Related to Calculating the Avoided Energy Rate

III. Issues Related to Calculating the Avoided Capacity Rate

## I. GENERAL OBSERVATIONS AND CONSIDERATIONS

**Q. WHAT ARE YOUR GENERAL OBSERVATIONS OF INTERVENOR TESTIMONY IN THIS PROCEEDING?**

A. Intervenors raise a variety of issues that suggest the North Carolinas Utilities Commission ("Commission" or "NCUC") should raise both the avoided energy and avoided capacity rates filed in this proceeding as well as extend the fixed price term of those rates. These recommendations are made despite overwhelming evidence that residents and businesses in North Carolina are paying substantially more for purchased qualifying facility ("QF") generation (specifically QF solar generation) than they would have for power generated by other means. In my view, the magnitude of the overpayment risk, pending the outcome of this proceeding, is a significant factor facing the Commission and the State, as a whole. While I will address several of these individual issues in my rebuttal testimony, I believe it is critically important to not lose sight of the overall impact of the energy and capacity value of QF power and QF solar power, in particular.

**Q. WHAT OVERALL FACTORS SHOULD THE COMMISSION CONSIDER IN DETERMINING THE REASONABLENESS OF THE COMPANIES' AVOIDED COST RATES FILED IN THIS PROCEEDING?**

A. Consideration should be given to the overall factors influencing the value of QF energy and the value of QF capacity. The two most important influencing factors for QF energy value are first, the underlying fuel prices that determine the value of avoided marginal system energy and second, the specific QF's ability to avoid those fuel purchases. With respect to QF capacity value, the principal consideration requires a valid comparison between how much generation will actually be avoided from the QF relative to how much the QF is being compensated for avoiding generation under the filed rates. Finally, it should be noted that a solar specific rate would produce a lower avoided cost rate as compared to the rates filed in this proceeding as discussed later in my testimony and by Witness Bowman in her rebuttal testimony.

**Q. OVER THE LAST TWO YEARS, HOW HAVE THE COMPANIES' SYSTEM MARGINAL COSTS AS DETAILED IN FERC FORM 714 TRENDED COMPARED TO THE AVOIDED ENERGY RATES APPROVED IN THE LAST AVOIDED COST PROCEEDING IN DOCKET NO. E-100, SUB 140 ("SUB 140")?**

A. The Companies calculated their previous 10-year annualized, non-hydroelectric ("hydro") energy rates pursuant to the Commission's December 17, 2015 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 140. Those rates that went into effect on March 1, 2016 were $42.90 per Megawatt-hour ("MWh") for DEC and $42.70/MWh for DEP, respectively. Comparatively, as filed in FERC Form 714, the Companies' system marginal costs dropped from approximately $33.65/MWh in 2015 to $29.16/MWh in 2016. This disconnect between system operating costs and avoided cost rates was mainly driven by the required inclusion of fundamental fuel prices in the Phase 2 Sub

140 Order's avoided cost rates, as well as a drop in delivered gas prices of nearly 20% across both Companies from 2015 to 2016.

**Q. PLEASE DESCRIBE HOW TRENDS IN THE NATURAL GAS MARKETS INFLUENCE THE UTILITIES' COST OF AVOIDED GENERATION ON A GOING FORWARD BASIS.**

A. There is little debate that advancements in shale gas production have changed the natural gas market landscape, drastically reducing the cost of natural gas. Consequently, and by extension, the Companies and other utilities' cost of avoidable energy production has also declined significantly over the last several years. This transformation has occurred at a rapid pace.

My Confidential Figure 1 demonstrates the average market fuel price of natural gas over the next ten years is 34% lower than prices used in calculating the avoided energy cost rate in the 2012 avoided cost proceeding, Docket No. E-100, Sub 136 ("Sub 136"), which used five years of market fuel prices and a one-year transition to a fundamental fuel forecast. The average price of natural gas is also 30% lower than those used in calculating the 2014 Sub 140 avoided energy cost rate, which included five years of market fuel prices and five years of fundamental fuel forecasts as directed in the Commission's "Phase 2" Sub 140 Order.[1]

[1] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* at 27-28, 54, Docket No. E-100, Sub 140 (Dec. 17, 2015) ("Phase 2 Sub 140 Order").

[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

Furthermore, on April 5, 2017, Duke Energy Progress purchased a long-term natural gas forward position that included the remainder of 2017 through the year 2026 at prices 6% percent lower than the relative prices used in establishing the 10-year small hydro rates filed in this proceeding and presented in Confidential Figure 1 above. Confidential Figure 2 further illustrates both the commodity trend and the attendant risk of establishing long-term QF rates that do not include periodic adjustments.

**[BEGIN CONFIDENTIAL]**

**[END CONFIDENTIAL]**

Notably, while the majority of my testimony focuses on natural gas price trends, coal prices have also seen declines since the Commission approved avoided cost rates in Sub 136 and Sub 140 as well. The average price of delivered coal over the next ten years is approximately 25% lower than prices used in calculating the 2012 Sub 136 avoided costs and approximately 8% lower than those used in calculating the 2014 Sub 140 avoided cost rates.

Locking in coal prices in long-term contracts carries similar risk as natural gas if rates do not include periodic adjustments.

**Q. PLEASE SUMMARIZE YOUR GENERAL OBSERVATIONS WITH RESPECT TO INTERVENORS' POSITIONS TO RAISE BOTH ENERGY AND CAPACITY RATES IN THE PROCEEDING.**

A. In summary, the Companies have historically produced energy well below what customers are paying for QF energy. On a forward-looking basis intervenors suggest substantial increases in the 10-year energy rate at the same time the Companies are relying on significantly lower market-based gas forecasts in their integrated resource planning process, and as the Companies have also recently purchased natural gas at costs even lower than those used in establishing the 10-year hydro rates filed in this docket. Additionally, that there is a large discrepancy in views over the long-term value of avoided QF energy also points to the risk of establishing long-term fixed energy rates especially above market levels as suggested by intervenors.

With respect to capacity rates, the use of general QF capacity rates as filed dramatically overstates the incremental capacity value of additional solar specific QF generation on the system. As DEC, DEP and Dominion North Carolina Power ("DNCP") have demonstrated the addition of incremental solar to their respective systems will have little to no impact on their need for capacity. Thus, I believe it is important for the Commission to consider these general factors and circumstances surrounding the proposed energy and capacity rates in this proceeding as it weighs specific issues brought forth.

## II. ISSUES RELATED TO CALCULATING AVOIDED ENERGY RATE

**Q. WHAT ISSUES WILL YOU BE ADDRESSING WITH REGARD TO THE ENERGY PAYMENT IN YOUR REBUTTAL TESTIMONY?**

A. I will be addressing:

1. Two-year Reset of Energy Prices vs. 10-year Fixed Prices
2. Market Prices vs. Fundamental Fuel Prices
3. The Merits of a Solar Only Energy Rate
4. Line Losses in Calculating Standard Offer Avoided Costs
5. Ancillary Costs in Calculating Standard Offer Avoided Costs

### TWO-YEAR RESET OF ENERGY PRICES VS. 10-YEAR FIXED PRICES

**Q. WHAT ARGUMENTS ARE MADE BY THE INTERVENORS AGAINST THE TWO YEAR RESET OF ENERGY PRICES VS. 10-YEAR FIXED PRICES?**

A. Public Staff Witness Hinton, North Carolina Sustainable Energy Association ("NCSEA") Witness Johnson, and Southern Alliance for Clean Energy ("SACE") Witness Vitolo each argue against the Companies' proposal to biennially reset energy rates as part of the 10-year standard offer contract. All three witnesses argue that this adjustment will not provide reasonable opportunity, in the words of Witness Hinton, "to attract capital from potential investors." [2] Witnesses Johnson and Vitolo argue that this adjustment would significantly increase the risks borne by QF developers, as well as, increase the risks borne by the Companies' customers.[3] Witness Vitolo additionally argues that this proposal treats QFs differently than assets owned by the Companies, even when the QF contracts represent a similar long-term fixed price obligation to the Companies' commitment to build a conventional generating plant. [4]

**Q. HOW DO YOU RESPOND TO THE INTERVENOR TESTIMONY THAT RESETTING THE ENERGY PRICES EVERY TWO YEARS WILL NOT ALLOW QFS TO OBTAIN FINANCING FOR QF PROJECTS?**

A. The intervening parties fail to acknowledge that the Companies are proposing a 10-year obligation to the QF with a known capacity payment and a known energy payment in the first two years. Over the 10-year term, the energy payment is reset every two years consistent with the then prevailing two-year rates as approved by the Commission. Ten-year purchase power agreements have been offered to and accepted by large solar QFs in the Companies'

[2] Public Staff Hinton Testimony, at 57-60.
[3] NCSEA Witness Johnson Testimony, at 158-160; SACE Witness Vitolo Testimony, at 19-20.
[4] SACE Witness Vitolo Testimony, at 20-21.

service area, demonstrating that the 10-year term is readily financeable. Accordingly, while the 10-year term is demonstrated to be financeable (at least for larger QFs), what intervenors are implying is that within the filed rates, not a large enough portion of the payment is fixed to attract financing. Unlike public utilities, QF developers are not required to make their financial and operating costs public, so it is unclear if these implications are factual. To my understanding nothing in PURPA requires states to offer price levels high enough to attract financing. The rate as filed in this proceeding, however, offers a sufficient term with a portion of the revenues fixed and a portion adjusted to better match future avoided energy value. It is fully consistent with PURPA and represents an appropriate adjustment to stem the persistent overpayment risk that our consumers are experiencing.

Moreover, the Commission has consistently stated it must "continually reconsider" the requirement for 10-year and 15-year contract terms as economic circumstances change from one biennial proceeding to the next. In past proceedings, the Commission has concluded that the 15-year maximum contract struck a balance between encouraging QF development and reducing the utilities' exposure to overpayments because the facilities entitled to long-term rates were generally of limited number and size. The significant proliferation of 5 MW solar QFs in the DEP and DEC service territories, however, has resulted in the number of QFs entitled to these long-term contracts no longer being of limited number and size. The proposed rate structure in this proceeding restrikes that balance between the development of

QFs and the Companies' exposure to overpayments when accounting for the current economic and regulatory circumstances.

**Q. SO YOU DISAGREE WITH NCSEA WITNESS JOHNSON'S ARGUMENT THAT MOVING TO A BIENNIAL UPDATE OF ENERGY PAYMENTS IS "LOSE-LOSE" FOR THE COMPANIES' CUSTOMERS?**

A. I strongly disagree with Witness Johnson's assertion. The move to a two-year reset is actually a "win-win" for the Companies' customers. Witness Johnson asserts that solar "currently brings a degree of pricing stability into electric rates; the benefits of that stability would be largely eliminated by this proposal." [5] Just because rates are stable, does not mean the customer benefits, especially if stability comes at the expense of rates that are unnecessarily high. For example, the utility could simply purchase ten years of natural gas at well above forward market prices for natural gas in the name of price stability. However I do not believe that would be in the best interest of customers. nor do I believe the Commission would find that practice prudent.

Witness Johnson also asserts that non-PURPA sellers of power who burn fuel are higher risk than solar QFs because those sellers "seek a pricing structure that gives them the ability to push the risk of fuel price changes forward to the purchasing utility, which in turn pushes the risk forward to their retail

[5] NCSEA Witness Johnson Testimony, at 158 -59

customers." [6] To support his assertion that those non-PURPA contracts are higher risk than the solar QF contracts, Witness Johnson points to my testimony stating the energy payments to those non-PURPA sellers "are generally linked to a real-time fuel price index." Witness Johnson fails to recognize, however, that the linking to a real-time fuel price index helps to lower risk, rather than increase risk. The non-PURPA contracts to which he is referring are third-party owned dispatchable natural gas units. Their dispatchable nature allows for the economic optimization of dispatch based on prevailing gas prices. For example, if gas prices rise the unit will run less while, conversely, when prices fall the unit will run more. On the other hand, PURPA must-take generation is not dispatchable and is taken at a fixed price without consideration to real time price signals or the Companies' real time need for energy to serve load. As such, there is no ability to adjust the amount of generation received based on real time price signals. As a result, customers only benefit if realized gas prices over time are consistently above those used in establishing the original QF rate. Unfortunately the exact opposite has consistently occurred in recent years resulting in significant customer overpayments and significant future overpayment risk.

**Q. IS PUBLIC STAFF WITNESS HINTON'S SUGGESTION TO "LINK AVAILABLE ENERGY RATES TO A PUBLICLY AVAILABLE**

[6] NCSEA Witness Johnson Testimony, at 160.

**COMPOSITE FUEL INDEX" A REASONABLE ALTERNATIVE TO THE TWO YEAR RESET OF ENERGY PAYMENTS?**

A. Yes, as discussed above, linking energy rates to a publicly available composite fuel index could be a reasonable alternative to the two year reset of energy payments. The linking of energy rates to a fuel index accomplishes a similar goal of minimizing the risk of overpaying QFs for the energy that they provide. As discussed by Witness Bowman, the Companies plan to further evaluate incorporating this proposal into the standard offer rate design in the next biennial proceeding,

**Q. PLEASE EXPLAIN THE COMPROMISE PROPOSAL THE COMPANIES ARE PRESENTING AS AN ALTERNATIVE TO THE TWO YEAR RESET OF ENERGY PAYMENTS IN THIS PROCEEDING.**

A. As discussed by Witness Bowman, the Companies have determined that offering small standard offer QFs the option to "fix" the two year avoided energy rate for the full 10-year term is an appropriate compromise in response to the testimony offered by intervenors that small QF investors will view energy revenues in years beyond the proposed biennial update as risky and that a longer-term fixed rate (seemingly for both energy and capacity) is needed by smaller QFs in order to attract capital. Currently, the Companies' two-year fixed Schedule PP annualized energy rates are only slightly below the fixed 10-year Schedule PP-H annualized energy rates, which I view as an acceptable, albeit imperfect, allocation of longer-term forecast risk between

QFs and the Companies' customers at this time. Further, as noted by Witness Bowman, the Companies submit this compromise alternative as an interim solution to address concerns raised in this case. The Companies plan to reevaluate these concerns in the next biennial avoided cost proceeding, along with the fuel index proposal offered by the Public Staff.

## MARKET VS. FUNDAMENTAL FUEL PRICES

**Q. PLEASE EXPLAIN THE COMMISSION'S RECENT CONCLUSIONS RELATED TO FORWARD MARKET FUEL PRICES VERSUS FUNDAMENTAL FORECAST-DERIVED FUEL PRICES IN ESTABLISHING AVOIDED ENERGY COST RATES.**

A. .In Phase 2 of the Sub 140 proceeding, the Companies' proposed to continue a trend initially begun in recent integrated resource plans ("IRPs") of more heavily relying upon forward market price data as a more precise indicator of the near-term future commodity costs of natural gas for purposes of calculating the Companies' avoided energy cost rates. Specifically, the Companies proposed to rely upon 10 years of forward market price data as a more accurate indicator of the future commodity costs of natural gas and to then transition to fundamental forecast data starting in year 11. However, at the time the Companies filed their proposed avoided cost rates in Sub 140 Phase 2, the Companies' then pending 2014 IRPs had relied upon only five years of forward market price data before transitioning to reliance on

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fundamental forecast data for the remainder of the Companies' 30 year planning horizon. In its Sub 140 Phase 2 Order, the Commission recognized that changing market conditions supported the Companies' increased reliance on forward market price data, acknowledging "the changing nature of the natural gas market and the fact that lower natural gas prices in the short- and long-term will result in benefits to ratepayers in the form of lower-cost electricity rates."[7] However, the Commission declined to approve the Companies' forecasts, emphasizing the important relationship between the Companies' IRP planning process and the biennial avoided cost proceedings, including the objective of maintaining internal consistency between these proceedings.[8] The Commission directed that, to the extent the Utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in future avoided cost proceedings, those changes shall first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations."[9]

**Q. WHY HAVE THE COMPANIES RELIED UPON 10 YEARS OF FORWARD MARKET FUEL PRICE DATA TO SUPPORT PRUDENT, LEAST-COST UTILITY RESOURCE PLANNING IN THEIR MOST RECENT BIENNIAL IRPS?**

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[7] Sub 140 Phase 2 Order at 27.
[8] Sub 140 Phase 2 Order, at 27-28.
[9] *Id.* at 55.

A. By 2014, it became apparent that the natural gas market in the United States had changed with the rapid increase in natural gas production due to technology advancements. With this increase in natural gas production, longer range options for purchasing natural gas became more available, and as a result, the Companies began requesting quotes for 10-year purchases of natural gas from various brokerage firms. As a result, the Companies have developed both their 2015 IRP updates, filed September 1, 2015, in Docket No. E-100, Sub 141 ("2015 IRP Update") as well as their 2016 biennial IRPs filed September 1, 2016 in Docket No. E-100, Sub 147 ("2016 Biennial IRP"), based upon 10-years of forward market price data and transitioning to fundamental forecast-derived data in year 11.

**Q. HOW HAVE GAS PRICES USED IN THE COMPANIES' IRPS AND AVOIDED COST DOCKETS CHANGED OVER THE LAST SEVERAL YEARS?**

A. Confidential Figure 3 below depicts the 10-year fuel prices from DEC's IRPs and avoided cost filings dating back to 2012. The figure also includes the most recent 10-year fuel purchase. If avoided cost rates were filed today, these lower fuel prices would be used in the calculation the avoided energy rate calculation.

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The 10-year levelized fuel prices have dropped nearly 40% since 2012 compared to the most recent 10-year fuel price quote received by the Companies in early April 2017. In fact, since the avoided cost rates were filed in mid-November 2016, the 10-year levelized natural gas price has dropped 6%.

**Q. DO THE FUNDAMENTAL FORECASTS THAT THE UTILITIES HAVE USED IN THESE SAME FILINGS REFLECT A SIMILAR TREND?**

A. Partially. The Fundamental Price Forecasts are clearly lagging the market prices in terms of seeing a structural difference in the natural gas marketplace. As shown in Confidential Figure 4 below, the Fundamental Price Forecast used in the 2016 Avoided Cost filing is showing natural gas price estimates at least $1/MMBtu higher than the actual market prices starting in 2020. It should be noted that fundamental forecasts take significant time to develop and are often only released by research firms once or twice per year. Additionally, the preparation of avoided cost filings also takes months to prepare and then can be subject to an extended regulatory review. As a result fundamental price estimates can be well over a year old by the time rates go into effect.

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**Q. REFERRING TO THE LONG-DATED GAS PURCHASE PREVIOUSLY MENTIONED, PLEASE COMPARE THIS MARKET PURCHASE WITH THE AVOIDED COST FUEL PRICES USED TO ESTABLISH RATES IN THIS DOCKET AS WELL AS WITH THE FUNDAMENTAL FUEL FORECAST SUGGESTED BY PUBLIC STAFF WITNESS HINTON.**

A. On April 5th, DEP purchased forward gas contracts for 2,500 MMBtu/day for the period starting in May of 2017 and ending in December of 2026. This transaction demonstrates market liquidity and provides a tangible price point for the natural gas market over the equivalent period of the 10-year hydro rate. As shown in Confidential Figure 5 below, the natural gas was purchased at a price just below the market prices used in the 2016 Avoided Cost filing. The 10-year levelized price of this purchased gas is approximately 6% lower than the market prices used in establishing the rates filed in this docket in November of 2016, and approximately 20% lower than the 5 year Market plus 5 year Fundamental Forecast blend of 10-year prices as suggested by Public Staff Witness Hinton. This highlights the overpayment risk I spoke of earlier regarding the suggestion to recalculate rates based on a fundamental forecast.

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**Q. WITH THAT BACKGROUND, HOW HAVE THE COMPANIES INCORPORATED THE USE OF 10 YEARS OF FORWARD MARKET FUEL PRICE DATA IN THEIR BIENNIAL AVOIDED ENERGY COST RATES PROPOSED IN THIS PROCEEDING?**

A. Consistent with the Companies' recent IRPs, 10 years of forward market price data is used to develop the Schedule PP-H rates proposed in this proceeding. However, because the Companies' Schedule PP non-hydro avoided energy cost rates are based only on the Companies' near-term, two-year forecasted avoided energy rates, the issue of reliance on forward market price data versus fundamental forecast data ten years out is a non-issue. This is significant, as the Companies' proposal best assures that future avoided commodity costs that underlie the near-term avoided energy rate are most accurate. If the Commission approves the Companies' proposed Schedule PP rate design, as proposed, the longer-term forecasted energy costs, and the associated risks of over-estimating or under-estimating future commodity costs based upon forward market data versus fundamental forecast data simply does not impact the Companies' proposed rates. However, if the Commission disagrees with the Companies' Schedule PP rate design to biennially reset the energy rate then the market price versus fundamental fuel forecasts arguments are significant both for purposes of this proceeding as well as for the Companies' prudent, least cost resource planning in future IRPs.

**Q. WHAT ARGUMENTS DO THE INTERVENORS MAKE AGAINST THE USE OF 10 YEARS OF FORWARD MARKET NATURAL GAS DATA, AS USED IN THE COMPANIES' 2015 AND 2016 INTEGRATED RESOURCE PLANS?**

A. Public Staff Witness Hinton argues that "ten-year futures are relatively illiquid, meaning that the number of natural gas price investors willing to make buy and sell decisions on prices ten years out in the future is much smaller than the number of investors in the futures market for five years into the future."[10] Witness Hinton also argues that the use of Fundamental Prices, that are "developed by energy economists and gas analysts" are more appropriate for long-term price forecasts because they are based on future supply and demand projections and "involve a more measured and tempered response to expected changes in the natural gas market."[11]

**Q. PLEASE RESPOND TO WITNESS HINTON'S CONCERN OVER MARKET LIQUIDITY.**

A. Based on my experience, long-dated forward contracts are liquid and transactable and may be purchased over-the-counter directly with large financial institutions and other firms rather than traded on the New York Mercantile Exchange ("NYMEX"). If one is simply viewing contracts that trade on the NYMEX that could lead to the conclusion that long-dated gas markets are illiquid. Typically only actual market participants that purchase or sell gas forward positions engage these financial institutions. It is an incorrect perception that liquidity does not exist in the long-dated forward markets as demonstrated by DEP's 10-year purchase of a natural gas forward position.

**Q. PLEASE RESPOND TO WITNESS HINTON'S CONTENTION THAT USE OF FUNDAMENTAL PRICES ARE MORE APPROPRIATE THAN USE OF ACTUAL MARKET PRICES.**

[10] Public Staff Witness Hinton, at 33.
[11] Public Staff Hinton Testimony, at 32.

A. There are several issues with this assertion.

First, this approach results in an immediate and extremely significant overpayment risk for customers. QF transactions represent significant forward purchased power obligations on behalf of customers. Today those transactions total more than $3 billion dollars. Very simply, the Companies may either purchase fuel or purchase power, or both, to satisfy future customer energy needs. PURPA requires customers be indifferent between the two. Use of fundamental price forecasts, rather than a transactable gas price, leads to avoided energy rates that are inconsistent with this indifference standard that is a bedrock principle of PURPA. By extension, if the Commission accepted Witness Hinton's argument to transact forward power QF purchases based on fundamental gas prices over market prices, it logically follows that the utility would also be deemed prudent to purchase natural gas at above available market prices so long as they were at or below fundamental projections. This highlights the inconsistency of purchasing power at forward fundamental forecasts while purchasing gas at market prices.

Second, Witness Hinton implies that his approach is more consistent with the avoided cost approach taken in Sub 140 Phase 2. However, in the Phase 2 Order, discussed above, the Commission emphasized that, to the extent the Utilities utilized forward prices and long-term forecasts to calculate their avoided energy rates, they should use the same approach as used in their

IRPs filed the same year.[12] Consistent with the Commission's instructions in the Sub 140 Phase 2 Order, the Companies have used 10-year forward market prices in their last two IRPs.

Third, Witness Hinton's recommendation to use fundamental prices is seemingly in conflict with his alternative recommendation to consider offering QFs avoided energy rates based on a composite commodity price index. For example, assume a straight forward natural gas commodity indexed QF rate. Such a structure would pay the QF a market based real time natural gas price index multiplied by a calculated average marginal heat rate of the utility's system. While this rate structure does not fix an energy price for the QF it allows the QF to fix its energy price at any point by forward hedging the gas price upon which the variable rates are based. This allows the QF to choose whether or not to fix their price of power at their discretion. The inconsistency in Witness Hinton's two positions comes from the fact that under his proposed alternative index structure the QF could only fix their revenues at the prevailing forward market price for natural gas (they could not hedge at fundamental price levels). By definition if the QF believed fundamental forecasts were pointing to higher prices they could opt to not fix prices at current market levels and take the risk that future prices rose to fundamental price forecasted levels. In contrast, by recommending the Companies adopt fundamental prices to set long-term rates in this Docket,

[12] Phase 2 Sub 140 Order, at 27-28, 55,

Witness Hinton is essentially suggesting that North Carolina consumers take on this risk by providing a transactable forward market for the QF at rates above the prevailing natural gas market. This transfers significant price risk to the consumer. As a result North Carolina would be in the unique position of creating a transactable forward power market well above the equivalent gas market. This dislocation between power and gas markets would certainly not be equitable for consumers.

**Q. HOW DO YOU RESPOND TO THE PUBLIC STAFF'S CONCERN THAT MARKET FUEL PRICES ARE EXCESSIVELY CONSERVATIVE AND THAT FUNDAMENTAL FORECASTS ARE A BETTER INDICATOR?**

A. I disagree. The use of market prices better aligns forward power prices and forward gas prices. Since Sub 140 Phase 2, when the Companies first proposed 10 years of market data, the market prices for natural gas have continued to substantially fall, proving that the natural gas market has shifted, and the lower prices are not just temporary.

**Q. WHAT ADDITIONAL ISSUES ARISE WITH USING FUNDAMENTAL FORECASTS AS A BASIS FOR CALCULATING QF AVOIDED ENERGY RATES?**

A. At any point in time only a single forward market exists for natural gas prices. Conversely, at any point in time a wide range of fundamental price forecasts are available. This range is clearly shown by the deviation between DNCP's fundamental forecast and the Companies' fundamental forecasts, as presented in the graph on page 35 of Witness Hinton's testimony, which I have replicated below as Confidential Figure 6.

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**[END CONFIDENTIAL]**

[13] Public Staff Hinton Testimony, at 35

As an initial matter, the Companies disagree with Witness Hinton's observation that reliance on the DEC 2016 IRP fundamental forecast and the DNCP avoided cost forecast approach are "more comparable."[14] As the graph clearly shows, the DEC 2016 IRP fundamental forecast, instead of being "comparable" to DNCP's avoided cost forecast highlights the varying fundamental views in the industry. Confidential Figure 6 shows that DNCP and DEC have very different fundamental forecasts, and I question whether setting QF rates based on materially different assumed gas prices is appropriate. Moreover, the Public Staff's reliance on fundamental forecasts for calculating avoided cost rates raises several issues, including identifying the criteria that would be used to establish the reasonableness of a fundamental price forecast, and what the positions of the intervenors would be if the fundamental forecasts were below the transactable market data. The Public Staff's testimony also raises the question of whether, going forward, the Commission will required to adopt a "preferred price forecast" for IRP and avoided cost proceedings. In addition to the DNCP and DEC forecasts, I am aware that multiple fundamental price forecasts are available; thus, determining the reasonableness of any one single fundamental price forecast over another may be difficult.

In sum, disagreements over which fundamental price forecast may be more accurate or whether forward market data is more reasonable for use in

[14] *Id.*

calculating future avoided cost rates masks the significantly more important question, which is "Have the Companies engaged in a reasonable and prudent, least-cost IRP planning process and is there a compelling reason to force inconsistency between the Companies' IRP methodology and their avoided energy cost methodology?" The Companies believe their current IRP methodology is reasonable and appropriate both for resource planning and for setting avoided energy cost rates. The Public Staff and other intervenors have failed to sufficiently explain why at this time the Companies should depart from the Commission's directive in its Phase 2 Sub 140 Order and not remain consistent with their previous IRP filings with respect to their fuel forecasts.

Finally, I also would reiterate that the Companies' proposed Schedule PP rate design using updated two-year energy forecast data to biennially reset avoided energy rates best mitigates the potential for long-term risk of over-estimating or under-estimating risk of commodity forecasts that may be wrong or markets that may change over time. As the two year rate is based on forward market gas prices it also maintains the critical link between forward QF power prices and forward market gas prices.

## THE MERITS OF A SOLAR ONLY ENERGY RATE

**Q. DO PUBLIC STAFF WITNESS HINTON AND NCSEA WITNESS JOHNSON ARGUE IN SUPPORT OF A SOLAR-SPECIFIC TARIFF?**

A. Yes. Public Staff Witness Hinton argues that energy provided by solar facilities during off-peak daylight hours has value that is not currently being fully recognized and properly allocated in off-peak avoided energy rates under the current method. Witness Hinton argues that a solar facility's generation helps to avoid a utility's marginal production costs during daylight hours when the marginal costs are generally higher. By modeling a solar-specific profile, the solar facility would not be penalized for not being available during nighttime off-peak hours and this would serve to increase the off-peak rate that solar QFs receive.

NCSEA witness Johnson argues that the Utilities "should focus on improving the rate design in ways that are responsive to the specific concerns that have been identified [by the utilities]." [15] Witness Johnson is concerned that "if the utilities continue to resist adopting technology-specific rates" other small power producers (i.e. wind, methane from landfills, hog or poultry waste and non-animal biomass) could be "penalized for problems (or perceived problems) that are specific to solar energy." [16]

**Q. DO THE COMPANIES SUPPORT MOVING TOWARDS A SOLAR-SPECIFIC AVOIDED ENERGY RATE FOR LARGER QFs?**

A. Yes, as also discussed by Witness Bowman, given the significant increase in solar QFs in the Companies' territories, use of a solar-specific rate in the

[15] NCSEA Witness Johnson Testimony, at 199.
[16] NCSEA Witness Johnson Testimony, at 198.

context of larger negotiated QFs is appropriate. Additionally, I believe it may be appropriate in subsequent standard offer filings to advance solar-specific QF rates.

**Q. WHAT FACTORS SHOULD THE COMMISSION CONSIDER REGARDING A SOLAR QF'S SPECIFIC IMPACT ON ENERGY VALUE?**

A. Generic QF rates established under the "Peaker Method" apply to any PURPA QF eligible for the Standard Offer. The Peaker Method as applied in North Carolina calculates energy value assuming an equal amount of generic QF generation is available in every hour. Fundamentally, non-baseload generation must track customer demand. Generation must be available and dispatchable to meet the dynamic needs of the consumer, which change minute-to-minute, hour-to-hour and day-to-day. Any utility system can only accommodate a finite amount of intermittent generation that does not follow load. The net impact of a large amount of this type of generation on a given system results in the need for additional operating reserves and other operating adjustments. The Companies have stated that the cost of these additional operational adjustments are also a growing concern that should be identified for larger QFs, but that are not included in the calculation of the filed standard offer rates for small QFs in this proceeding.

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**Q. HOW WOULD THE COMPANIES SUGGEST IMPLEMENTING A SOLAR-SPECIFIC ENERGY RATE IF DIRECTED TO BY THE COMMISSION IN THIS PROCEEDING?**

A. To calculate the energy specific portion of the avoided cost rates for solar QFs, the Companies would simply perform two production cost runs; one with, and one without, 100 MW of free solar generation using a general diversified solar profile. Today QF energy rates are generated using the same approach but assuming the free 100 MW is flat baseload generation in every hour. The use of a solar-specific profile could provide a more representative view of the actual system marginal energy benefits associated with incremental solar QF generation as opposed to the generic energy rate that assumes equal production in all hours.

**Q. PUBLIC STAFF WITNESS HINTON SUGGESTS THAT SOLAR OFF-PEAK RATES WOULD INCREASE BETWEEN 8% AND 10% DUE TO THE DIURNAL PROFILE OF SOLAR COINCIDING WITH HIGHER COST OFF-PEAK HOURS. HOW DO THE COMPANIES RESPOND?**

A. In response to a request from the Public Staff in this proceeding, the Companies conducted an analysis to produce an avoided energy rate under the traditional peaker method, but altered to include only a daylight hours solar load shape rather than a constant 100MW as used in the development of the standard offer tariff. Because the alternative analysis calculated avoided energy value using a free 100MW solar load profile to generate the associated energy value (energy rate) as compared to the filed rate that included 100MW free baseload resource in every hour of the year, the Companies agree that it represents a more precise estimate of the value of incremental solar-specific energy for solar QFs as compared to the filed standard offer rates.

Based on this analysis, a solar-only energy rate that more precisely calculates the energy value of solar based on the load characteristics of a solar resource would result in avoided energy rates that on an annual average would be approximately 10% *lower* on average than the rates solar QFs are receiving under the generic small QF standard offer tariff that assumes constant energy production around the clock.

**Q. WHAT ARE THE DRIVERS THAT LEAD TO A LOWER AVOIDED ENERGY COST RATE USING A SOLAR-SPECIFIC PROFILE?**

A. Several factors influence this result.

First, the non-coincident nature of the solar shape with the Companies' load is a major contributor to the lower avoided cost rates with a solar-specific load profile. As shown in Figures 7 and 8 below, peak load typically occurs between 7 AM and 8 AM in the winter (using January as a representative data point) and between 4 PM and 5PM in the summer (using July as a representative data point). The peak for solar output typically occurs between 1PM and 2PM in the winter and between 2PM and 3PM in the summer. Additionally, and more importantly, on winter mornings solar generation starts providing energy to the system just as load is decreasing, and solar output begins to decline just as load is rebounding during winter evening hours. In the summer, solar aligns better with load, but again, solar output begins to decline as system demand is growing toward its afternoon peak.

As a simple example of solar's non-alignment with system load, consider that customers have varying needs over each of the 8,760 hours of a given year. Solar resources are available on a varying basis in approximately 55% of all the hours in the year. Of those hours in which solar is available, based on 2016 data, it only moved in the same direction as load about half of the time. The figures below also show that during critical peak hours is precisely when solar is moving the opposite direction of customer demand.

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**Figure 7: Average DEP Projected Load Shape for January Based on Forward 10-Year Load Forecast Overlaid with Average January Solar Shape**

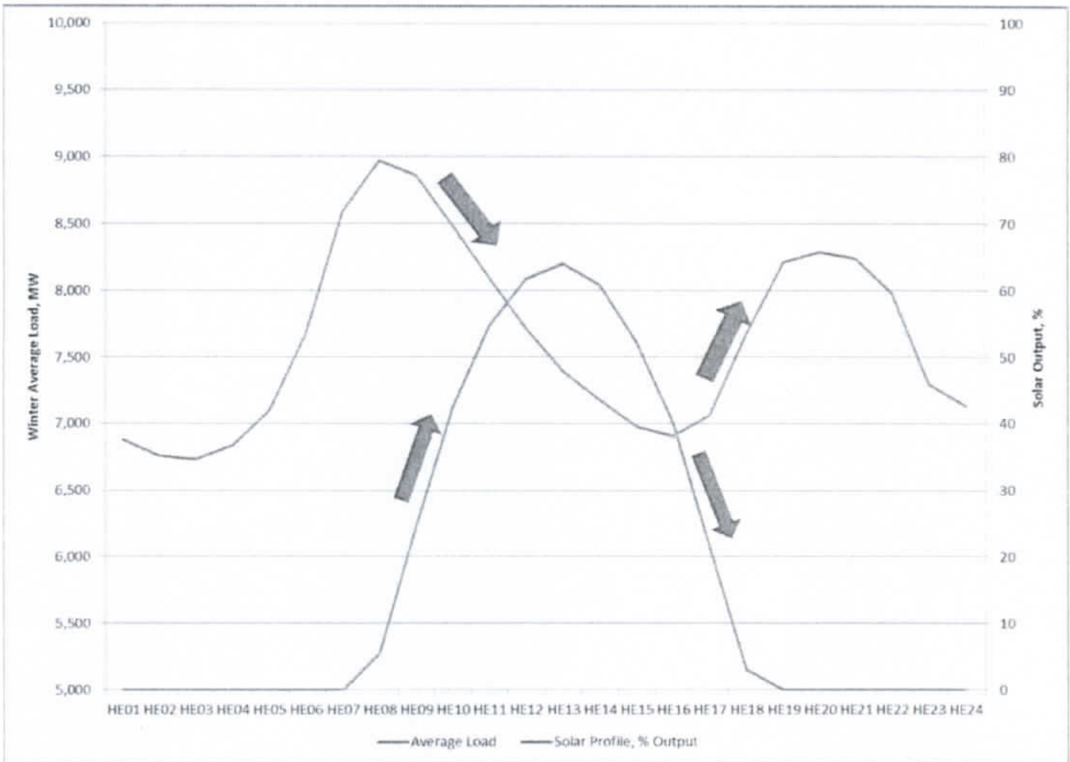

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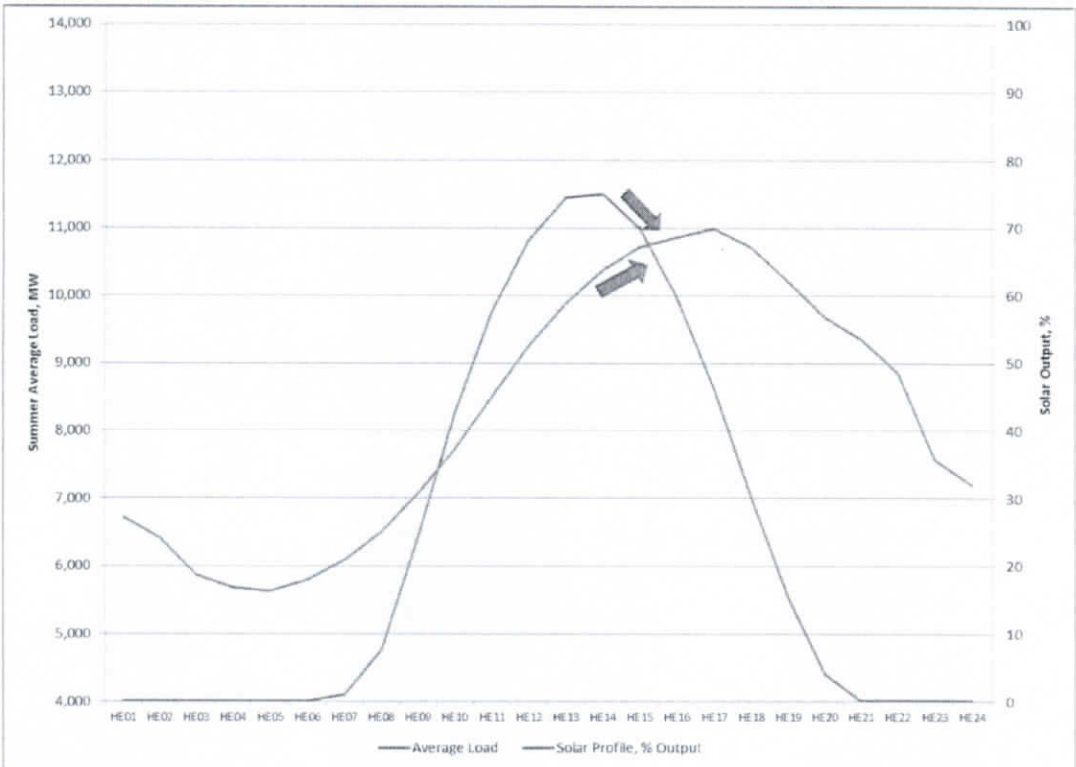
**Figure 8: Average DEP Projected Load Shape for July Based on Forward 10- Year Load Forecast Overlaid with Average July Solar Shape**




Further, as Figures 9 and 10 show below, as more and more solar is added to the system, the more non-coincident the solar shape becomes versus the load profile.

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**Figure 9: Average DEP Projected Load Shape for January with 1,000 MW Increments of Solar Generation**

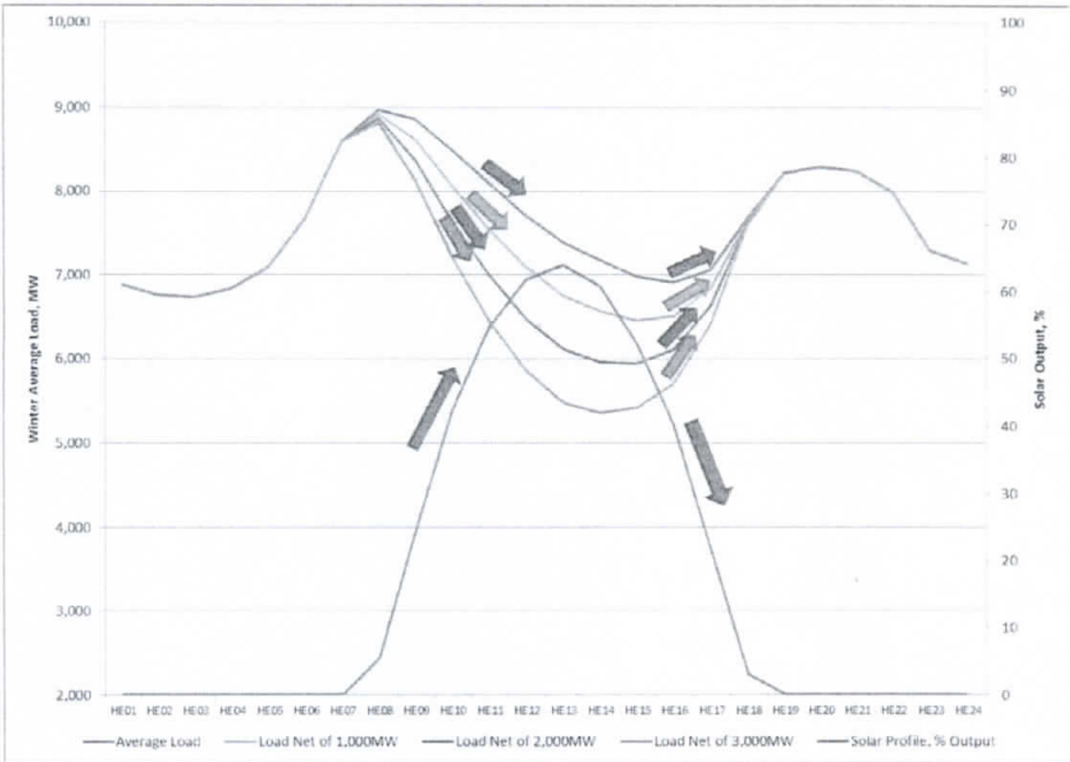

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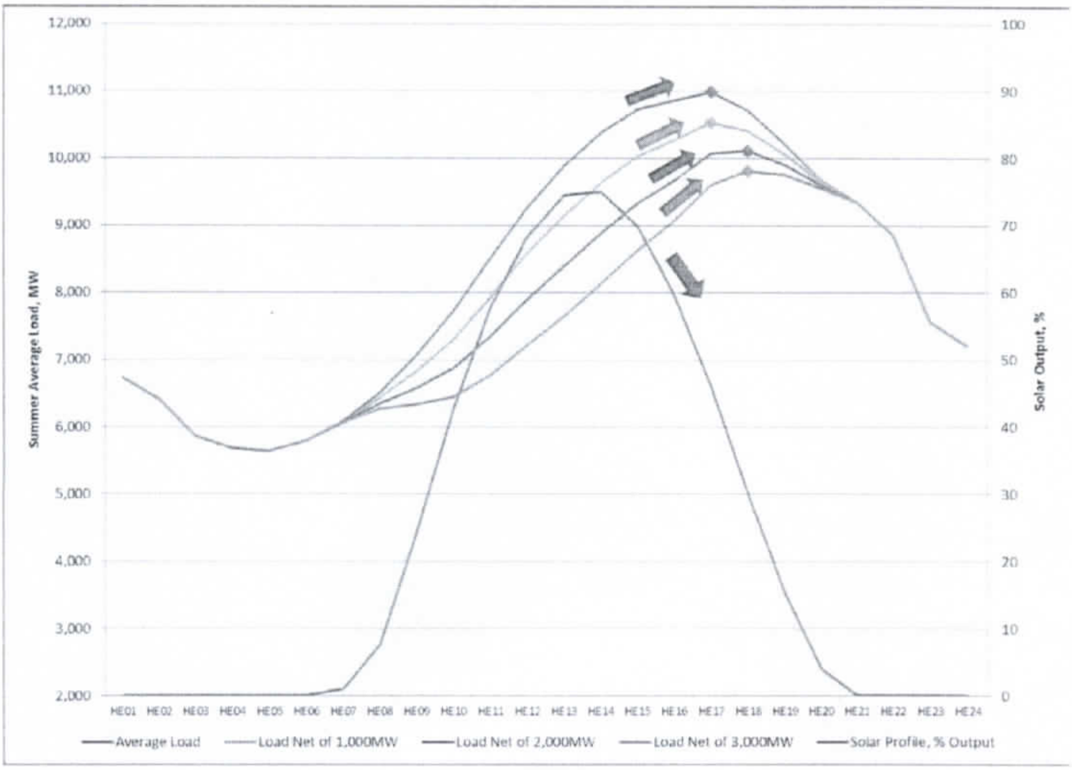
**Figure 10: Average DEP Projected Load Shape for July with 1,000 MW Increments of Solar Generation**




Because a solar profile is not coincident with load, it lacks coincidence with the Companies' highest marginal cost hours in both the winter and summer months. Figures 11 and 12 show an example of the system marginal costs overlaid with the solar load shape for both the winter and summer months using January and July averages respectively as representative data points. As the figures show, solar is not producing at high levels during the Companies' highest system marginal costs periods. As the figures also depict, solar is not fully available during the Option B on-peak hours for non-summer months (grey box). Under the current energy rate structure, which provides solar QFs with a rate based on a flat 100 MW load profile, QFs with solar generation profiles are being over-credited for energy during on-peak hours.

**<u>Figure 11: 10-Year Levelized DEP Projected Hourly Marginal Costs for January Overlaid with Average January Solar Shape</u>**

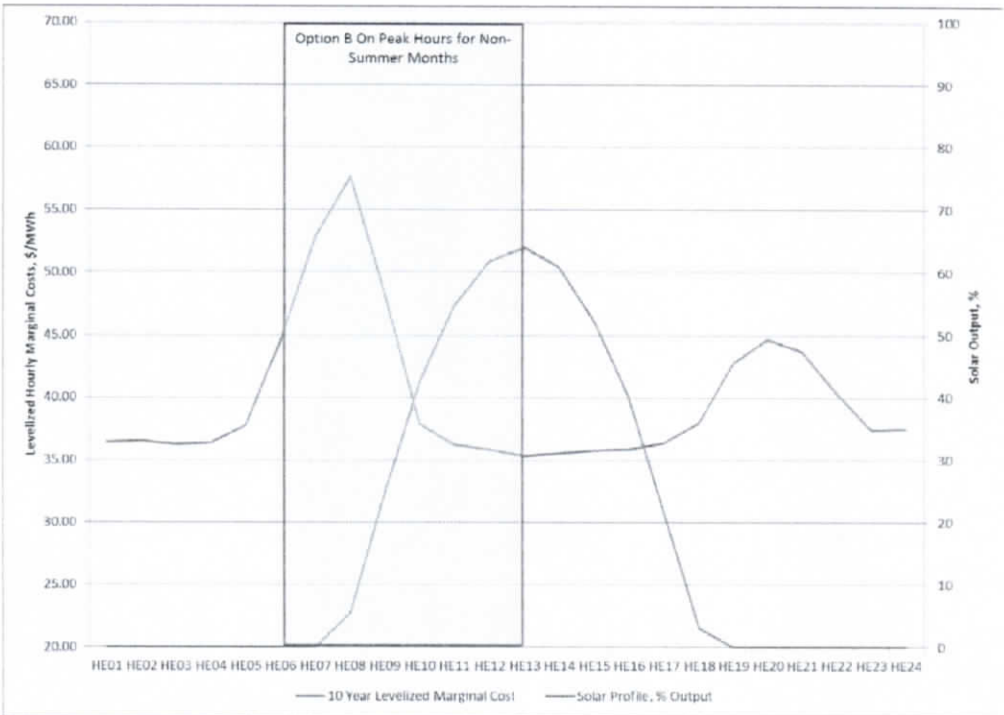
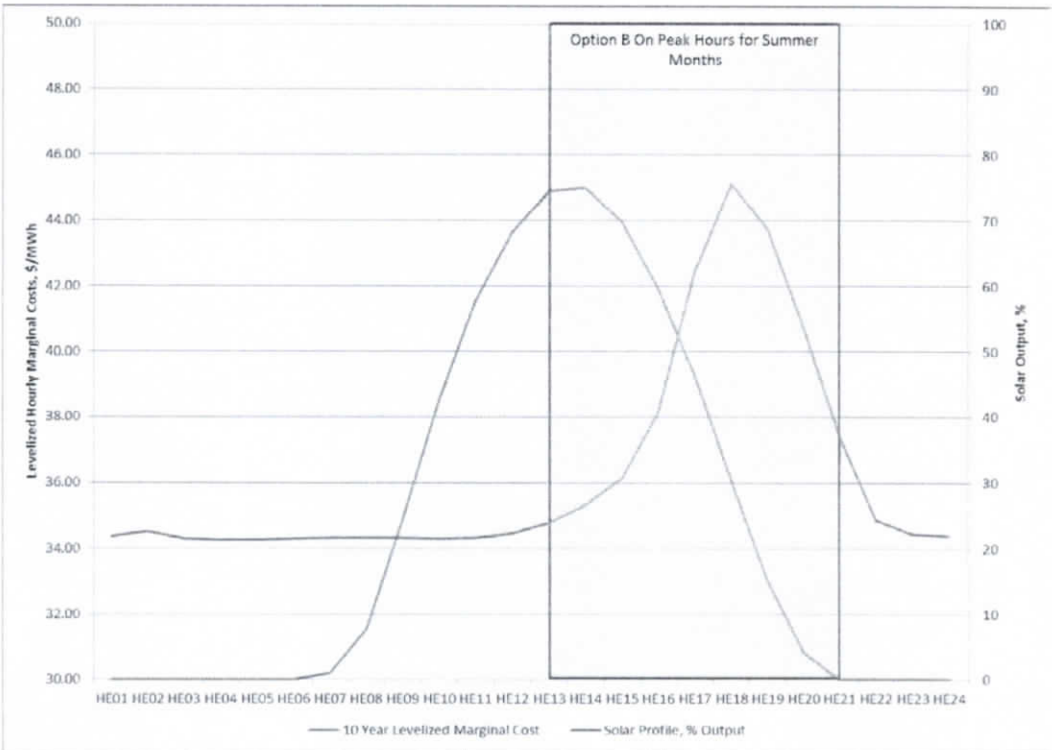


**Figure 12: 10-Year Levelized DEP Projected Hourly Marginal Costs for July Overlaid with Average July Solar Shape**




**Q. HOW DO THE COMPANIES SUGGEST VALUING THE AVOIDED CAPACITY RATE IN THE CONTEXT OF A SOLAR-SPECIFIC QF RATE?**

A. With respect to the capacity value of solar, the Companies would strive to align the capacity rate paid to solar with the amount of avoided capacity that solar resource will produce. As discussed by Witness Bowman, a large, utility-scale solar QF has unique characteristics that should be taken into account when considering the value of a solar-specific QF on the system outside of the standard QF rate offering. In particular, a solar QF is intermittent, it is non-dispatchable and, as such, not capable of following customer load. Importantly, its output profile is not coincident with system peak and, as I have mentioned, it is important to consider that during high demand periods, solar generation is ramping up when peak loads are declining and solar generation is falling off when customer demand is increasing. The culmination of these factors bring into question the appropriateness of ascribing significant capacity value to additional solar resources.

**Q. DO YOU BELIEVE THE CHANGES YOU ARE SUGGESTING FOR LARGER QFS ARE RESPONSIVE TO NCSEA WITNESS JOHNSON'S SUGGESTION THAT THE "COMMISSION INITIATE STEPS TO PROVDE STRONGER, MORE PRECISE PEAK AND OFF-PEAK PRICE SIGNALS IN THE QF TARIFFS" TO ENCOURAGE SMALL POWER PRODUCERS TO "PROVIDE MORE OF THEIR POWER WHEN IT IS MOST VALUABLE, AND LESS WHEN IT IS LEAST VALUABLE?"** [17]

A. Yes, as described above, the move towards using a solar-specific load profile to calculate negotiated QF rates along with potential changes in subsequent biennial avoided cost filings will provide price signals to QFs that reflect the specific characteristics of the QF as envisioned in PURPA.

[17] NCSEA Witness Johnson Testimony, at 197 – 98.

**LINE LOSSES IN CALCULATING STANDARD OFFER AVOIDED COSTS**

**Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS METZ'S SUGGESTION THAT IT MIGHT BE APPROPRIATE FOR DEP TO CONSIDER ELIMINATING THE LINE LOSS ADDER DUE TO REVERSE DISTRIBUTION TO TRANSMISSION POWER FLOWS IN FUTURE PROCEEDINGS?**

A. The Companies agree with Witness Metz's suggestion that DEP consider eliminating the line loss adder in future biennial avoided cost proceedings. Further, as discussed above, and further described by Witness Bowman, the Companies may also evaluate this issue as part of the specific avoided cost characteristics for larger distribution-connected QFs.

**ANCILLARY COSTS IN CALCULATING STANDARD OFFER AVOIDED COSTS**

**Q. ARE THE COMPANIES ADDRESSING THE NEED TO INCLUDE ANCILLARY COSTS ASSOCIATED WITH SOLAR QFS IN THIS FILING?**

A. From a system operations perspective, ancillaries are an additional issue that needs to be addressed with larger QFs and are dependent on the characteristics of the specific QF in question. The Companies have not included ancillary costs in deriving the standard offer avoided energy rates in this docket.

However, an ancillary decrement in future biennial avoided cost proceedings, particularly in the context of a potential future solar-specific standard offer rate, may be appropriate.

## III. ISSUES RELATED TO CALCULATING THE AVOIDED CAPACITY RATE

**Q. WITNESS HINTON REFERENCES THE MAIN FACTORS INFLUENCING CHANGES IN THE COMPANIES' AVOIDED CAPACITY RATES FROM THE PRIOR RATES AS FILED IN SUB 140. DO YOU AGREE WITH HIS SUMMARY OF THE FACTORS THAT HAVE BEEN ADJUSTED?**

A. I do agree with his summary of the factors that have been adjusted since the prior rates were filed in Phase 2 of Sub 140. In particular, the primary areas of adjustment that Witness Hinton refers to are:

i. Recognizing capacity value starting with the first year of actual need as shown in the Companies' respective IRPs;

ii. Changes to the Performance Adjustment Factor; and

iii. Changes to the weighting of capacity payments between the winter and summer peak seasons.

I will address concerns with changes to these components of the capacity rate valuation.

## RECOGNIZING CAPACITY VALUE STARTING WITH THE FIRST YEAR OF ACTUAL NEED

**Q. NCSEA WITNESS JOHNSON SUGGESTS THAT THE INCLUSION OF NO CAPACITY VALUE PRIOR TO THE UTILITY HAVING A NEED FOR CAPACITY IS DISCRIMINATORY TOWARD QFS. DO YOU AGREE WITH HIS ASSERTION? [18]**

A. I do not. Rather, I agree with Public Staff witness Hinton. The inclusion of capacity value that is not actually avoidable results in an overpayment by consumers, in violation of PURPA. Witness Johnson mistakenly assumes that utilities "overbuild" resulting in excess capacity that is fully recoverable. He ignores the critical point that utilities are not overbuilt due to the addition of larger resources. Instead, when a larger unit is selected in a resource plan, it is because that resource is the most economic resource option for consumers. When building larger units, the Companies achieve economies of scale and operating efficiencies that provide a more economic and efficient solution for consumers as compared to smaller increments of generation. Small increments of generation that put the utilities at their minimum reserve margin targets in every year are not economically optimal for consumers (especially when the utilities cannot control and dispatch the generating resource being built). This is a popular misconception, often advanced by proponents of

[18] NCSEA Johnson Testimony, at 183.

small scale generation over central station utility-owned generation. I recognize that the IRP and Certificate of Public Convenience and Necessity ("CPCN") processes often result in periods of reserves in excess of minimum reserve targets. Importantly, this selection of a larger scale resource is done after a careful consideration of all the costs and benefits of smaller scale generation versus larger scale generation. As a result, a QF can only provide capacity value if there is an avoidable capital investment that can actually be deferred. Under any circumstance, it harms consumers to pay for capacity that is not actually avoided. Adhering to this basic principle does not discriminate against a QF but rather complies with PURPA's fundamental mandate to ensure consumers are not paying more for QF generation than they otherwise would utility generation.

## PERFORMANCE ADJUSTMENT FACTOR (PAF)

**Q. PRIOR TO ADDRESSING CONCERNS RAISED WITH THE PAF, PLEASE EXPLAIN WHAT A PAF IS AND HOW IT IMPACTS THE CAPACITY RATE FILED IN THIS PROCEEDING.**

A. As I discussed in my prefiled direct testimony, the PAF is a simple multiplier that increases the avoided capacity rates paid by customers and received by the QF. The PAF included in the Companies' avoided capacity rates for small non-hydro QFs is 1.05. The 1.05 PAF represents a change from the PAF approved in Sub 140, which applied a 1.2 PAF to the avoided capacity rate.

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Mathematically, applying a 1.2 PAF essentially increases the capacity payment made by the Companies' customers to QFs by 20% while a 1.05 PAF increases the capacity payment by 5%.

**Q. DO YOU AGREE WITH THE RATIONALE FOR INCLUDING A PAF IN THE GENERIC CAPACITY PAYMENT TO QFS AS APPLIED IN NORTH CAROLINA?**

A. Yes, I do. In general, I agree that a generic QF should not be held to a standard that requires 100% availability during peak hours to receive payments equivalent to the utility's full avoided capacity cost. Because all generating facilities, including the facilities deemed avoided through QF purchases, experience some degree of unavailability, applying a PAF is reasonable. I believe that the objective of the PAF should be to ensure that a QF operating with a reliability equivalent to that of an avoided CT receives the full capacity value of the CT. As discussed later in my testimony, it is also reasonable under the peaker method to view the "on-peak" reliability of baseload generation resources on the Companies' systems as equivalent to a reasonable expectation of QF availability. Both metrics, when properly applied, support a PAF of 1.05 as an appropriate availability adjustment to the QF capacity rate.

**Q. WHAT DO YOU MEAN BY "RELIABILITY EQUIVALENT" TO THAT OF AN AVOIDED CT OR BASELOAD UNIT?**

A. In simple terms, the avoided unit has a forced outage rate that can impact its availability during on-peak periods and thus affect system reliability and the reserve margin needed by the Companies to provide reliable service. Thus, the purpose of the PAF is to place the QF and avoided unit on the same basis in terms of their impact on system reliability.

**Q. AS A SIMPLE MATTER OF COMPARISON, WHAT IS THE RELIABILITY OF A CT?**

A. As I have previously testified, the appropriate measure of reliability for a CT peaking unit is the starting reliability. The Companies' CT fleet performs at a starting reliability of approximately **[BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]**. Although a PAF of **[BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]** could be supported, my recommendation is to establish the PAF at 1.05 as a conservative measure to ensure that QFs receive fair capacity payment compensation. Further, it is my belief that no greater than a 1.05 PAF is warranted as anything greater would represent a subsidy given to smaller QFs and subject customers to unfair, unjust, and unreasonable rates that exceed the costs actually being avoided.

**Q. DO YOU BELIEVE THAT THE CT RELIABILITY EQUIVALENCE RATIONALE JUSTIFIES A 1.2 PAF, AS APPLIED TO SOLAR QFS UNDER THE RATES APPROVED IN SUB 140?**

**A.** No. A PAF of 1.2 effectively means that a QF must only be available 83% of peak hours to receive payments equivalent to 100% of a utility's full avoided capacity costs. As explained in my testimony, a 95% availability equating to a 1.05 PAF is a more appropriate representation of a unit's availability as explained subsequently.

**Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESSES HINTON'S AND METZ'S SUPPORT FOR A PAF OF 1.16 WHICH IS BASED ON AN AVERAGE BASELOAD AVAILABILITY FACTOR OF 86.33%?**

A. The Public Staff's focus on "availability" is approproiate, but their calculation has a critical flaw that leads to substantial overstatement of a just and reasonable PAF. Let me start by explaining a generator's "availability factor." The availability factor of a power plant is the amount of time that it is able to produce electricity over a certain period, divided by the amount of the time in the period. Apparently, the time period used in the Public Staff's calculations was based on annual data. Witnesses Hinton and Metz are testifying that the average availability factor for certain DEC, DEP, and DNCP baseload and intermediate units was about 86% during the period 2011-2016. Notably, the numerator of the availability factor reflects (i.e., is reduced by) the amount of time that a unit is out of service for planned maintenance. Thus, the annual availability factor measures how much a unit is available across an entire year which includes these planned outages such as nuclear refueling outages. Planned maintenance is typically conducted during off-peak shoulder periods when electricity demand is low. As such using the annual availability factor for the Companies' generating fleet is not relevant to the intended purpose of the PAF, which applies only to on-peak periods. By definition, off-peak periods have very low loss of load risk even with the planned maintenance outages. Of greater importance, QFs do not have to produce a single MWh in off-peak hours to receive their full capacity payment. While conversely, Public Staff is using off-peak planned maintenance from utility generation to effectively increase the proposed PAF they are recommending for QFs. By way of example, that would imply that an acceptable operational practice would be to schedule a nuclear unit refueling outage during peak demand periods. Obviously, that is not representative of prudent utility operating practice. In fact, the Companies strive to take outages, planned or not, during lower load or off-peak periods when capacity is not needed. In summary, any availability metric used to support a PAF must focus solely on the peak availability and not annual availability. It is simply mathematically incorrect to base a PAF on annual availability of utility generation which includes off-peak outages as a measure of on-peak performance for a QF

**Q. WHAT WOULD THE IMPLICATIONS BE IF THE COMPANIES' GENERATING FLEET OPERATED AT THE ON-PEAK PERFORMANCE THAT THE PUBLIC STAFF RECOMMENDS FOR SETTING A PAF FOR QFS?**

A. Since utility reserve margins are based on on-peak availability of greater than 95%, imposing an assumed 86% peak availability would result in a significant increase in the Companies' reserve margin requirement and significant increase in costs to consumers to build or buy greater amounts of capacity in order to provide reliable service.

**Q. NCSEA WITNESS JOHNSON CONTENDS THAT UTILITIES ARE NOT HELD TO THIS HIGH STANDARD OF 95% AVAILABILITY. HOW DO YOU RESPOND?**

A. Clearly the Companies manage their generation fleets to achieve a very high level of on-peak reliability. For example, the nuclear fleet, in the context of a utility fuel case, has the burden of proof to demonstrate high availability relative to industry peers as a matter of prudence. If you adjust for off-peak refueling outages, as described above, and solely examine the fleet's performance during peak summer and winter months you would see peak availability well in excess of 95%. Furthermore, consider that DEC and DEP combined operate over 36,000 MWs of capacity. Accepting the Public Staff's assertion that 86% availability is just and reasonable in setting a PAF implies that during peak periods, it would be reasonable for the Companies to have 5,000MW of generation unavailable during any given peak hour. With over 25 years of utility experience, I find it difficult to assume that Commission would find it acceptable for the Companies to average 5,000 MW of unit outages over the entire winter and summer period.

Q. **IF THE COMMISSION BELIEVES THAT THE PAF SHOULD BE BASED ON SYSTEM AVAILABILITY, AS THE PUBLIC STAFF RECOMMENDS, AS OPPOSED TO AVAILABILITY OF THE CT, WHICH SERVES AS THE BASIS FOR THE CAPACITY PAYMENT UNDER THE PEAKER METHOD, WHAT IS THE APPROPRIATE AVAILABILITY METRIC THAT SHOULD BE USED?**

A. If the Commission believes that the PAF should be based on a system availability metric, then it should be based on a metric that represents the reliability of the system during peak demand periods, and I would recommend using the Equivalent Forced Outage Rate ("EFOR"). EFOR represents the reliability of a unit or generating fleet during periods between planned maintenance intervals which means that it is a better indicator of the reliability of the unit or fleet during peak demand periods when performance is critical.

Q. **HAVE YOU CALCULATED A SYSTEM WEIGHTED AVERAGE EFOR VALUE FOR THE COMPANIES?**

A. Yes, a system weighted average EFOR value was calculated as part of the 2016 resource adequacy studies to give an idea of the total system EFOR performance. The annual system weighted average EFOR for DEC was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and for DEP was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

**Q. IF AN ON-PEAK EFOR WAS ADOPTED AS THE BASIS FOR ESTABLISHING THE PAF, WHAT VALUE OF PAF WOULD YOU SUPPORT?**

A. Similar to the CT starting reliability data, the EFOR data from the 2016 resource adequacy studies again supports a PAF less than, and certainly no greater than, 1.05.

**Q. WHAT IS YOUR RESPONSE TO NCSEA WITNESS JOHNSON'S ASSERTION THAT REDUCING THE PERFORMANCE ADJUSTMENT FACTOR TO 1.05 WOULD HAVE THE EFFECT OF REQUIRING A QF TO PRODUCE AT FULL CAPACITY DURING 95% OF THE ON-PEAK HOURS TO RECEIVE FULL AVOIDED CAPACITY COSTS?**

A. I agree with Witness Johnson's statement that a PAF of 1.05 would require a QF to operate 95% of on-peak hours to receive a full capacity payment. I further recognize that the rates filed are generic rates applying to all QFs, with origins dating back to non-dispatchable baseload gas co-generators. Notably, if a solar QF, or any other QF for that matter, was truly dispatchable, then the Companies would be open to a demand rate that would allow that dispatchable QF to receive capacity payments consistent with other dispatchable capacity resources the Companies purchase outside of PURPA. The dispatchability allows these resources to receive full capacity payments without producing in 95% of on-peak hours. It is the very non-dispatchable nature of QF power that requires the QF to operate across the peak to receive a full capacity payment. If the QF were dispatchable, capacity could be paid based upon dispatch performance like other generation outside of PURPA. This is a key point that is often lost in the comparison of non-QF capacity and QF capacity. In fact, PURPA specifically envisions issues like intermittency and dispatchability to be factored into the rate structure and valuation.

**Q. EXCLUDING APPLICATION OF THE PAF, APPROXIMATELY WHAT PERCENTAGE OF THE AVOIDED CT COST WOULD A TYPICAL SOLAR QF BE COMPENSATED FOR BASED ON THE COMPANIES' RATES IN THIS DOCKET?**

A. As I stated in my direct testimony, given the broad definition of on-peak hours in the current rate structure, under Option B of Schedule PP, a typical solar facility would be compensated for avoiding approximately 40% of its nameplate capacity in equivalent avoided "peaker" capacity while only providing an actual capacity value of 5% or less. This means that each MW of QF solar would be compensated for almost 40% of the cost of a CT while providing only 5% of the capacity value that a CT would provide.

**Q. DO YOU BELIEVE THAT YOUR RECOMMENDATION TO ADJUST THE PAF FROM 1.2 TO 1.05 IS FAIR TO THE QFS AND TO THE COMPANIES' CUSTOMERS?**

**A.** Yes, I do. While the precise method and basis for calculating a PAF can be debated, the reliability of a CT and the reliability of the Companies' entire generating fleet both support a PAF of no greater than 1.05. A PAF of 1.05 appropriately aligns the capacity payment adder to the correct reliability metric and thus fairly compensates a generic standard offer QF for the capacity value that they provide under the peaker method. Further, I believe the adder is reasonable and provides just and fair rates to the Companies' electricity consumers.

## SEASONAL WEIGHTING

**Q. HAVE ANY INTERVENORS QUESTIONED THE COMPANIES' CHANGE IN SEASONAL CAPACITY VALUE ALLOCATION FROM 60/40 SUMMER/WINTER TO 80/20 WINTER/SUMMER?**

A. Yes, based on testimony in this docket as well as comments in Docket No. E-100, Sub 147, there appears to be some misunderstanding regarding the fundamental findings and conclusions of the resource adequacy studies presented in the Companies' 2016 Biennial IRPs, the need for the Companies' shift to winter capacity planning, and the associated seasonal capacity value allocation. Although it is not entirely clear, intervenors seem to associate the need for winter capacity planning with winter peaking. For example, Witness Hinton states:

> As the Public Staff stated in its comments in the 2016 IRP Proceeding, the shift of DEC and DEP from summer to winter peaking should not diminish consideration of the summer peak, which remains significant. . . . Until a pattern of winter peaks is better understood and there is

> more confidence that the Company is a winter peaking utility, shifting to a predominantly winter-centric paradigm may be premature. [19]

**Q. WITNESS HINTON'S STATEMENT ABOVE REFERENCES THE PUBLIC STAFF'S COMMENTS IN THE 2016 IRP PROCEEDING (DOCKET NO. E-100, SUB 147). WHAT COMMENTS DID THE PUBLIC STAFF MAKE IN THE 2016 IRP PROCEEDING REGARDING WINTER PEAKING VERSUS WINTER CAPACITY PLANNING?**

A. The Public Staff's recent comments in the 2016 IRP proceeding provide:

> DEP and DEC's shift from being summer peaking systems to a winter peaking systems means that their reserve margins are designed to meet the winter peak. [20]

**Q. IS THE ASSOCIATION OF WINTER PEAKING AND WINTER CAPACITY PLANNING CORRECT?**

A. It is not.

**Q. PLEASE EXPLAIN WHAT YOU MEAN BY WINTER CAPACITY PLANNING.**

A. As I explained in my direct testimony, the load and resource balance has changed drastically in the past two-to-three years, driven primarily by the high penetration of solar resources as well as the significant load response to recent cold weather. Furthermore, winter peak demands are more sensitive to weather volatility than summer peak demands. Despite the fact that solar

[19] Public Staff Hinton Testimony, at 25-26.
[20] Comments of the Public Staff, 2016 Biennial Integrated Resource Plans and Related 2016 REPS Compliance Plans, at 42 Docket No. E-100, Sub 147 (filed Feb. 17, 2017)

output is declining going into the afternoon summer peak, solar resources still contribute significantly more to the summer afternoon peak periods than they contribute to the winter morning peaks. Even if the weather normal peak is in the summer DEC and DEP must still "plan" based on a winter peak reserve margin criteria as a result of existing and anticipated solar on the system. Definitively, a summer reserve margin target will no longer ensure adequate reserve capacity in the winter, as winter load and resources now drive the timing need for new capacity additions. This was described on page 31 of the 2016 DEC Biennial IRP and page 32 of the 2016 DEP Biennial IRP. The transition to winter capacity planning, via use of a winter reserve margin target is essential to ensure that adequate reserves will be available throughout the year as required to provide acceptable resource adequacy.

**Q. IN RECENT YEARS, HAVE THE DEC AND DEP ANNUAL PEAKS TYPICALLY OCCURRED IN THE SUMMER OR WINTER?**

A. As shown in Figures 12 and 13 below, during the last five years (2012-2016), DEC's annual peak has occurred in the winter in 2 out of the 5 years and DEP's annual peak has occurred in the winter in 4 out of the 5 years.

**<u>Figure 12: Historical DEC Winter and Summer Peaks</u>**

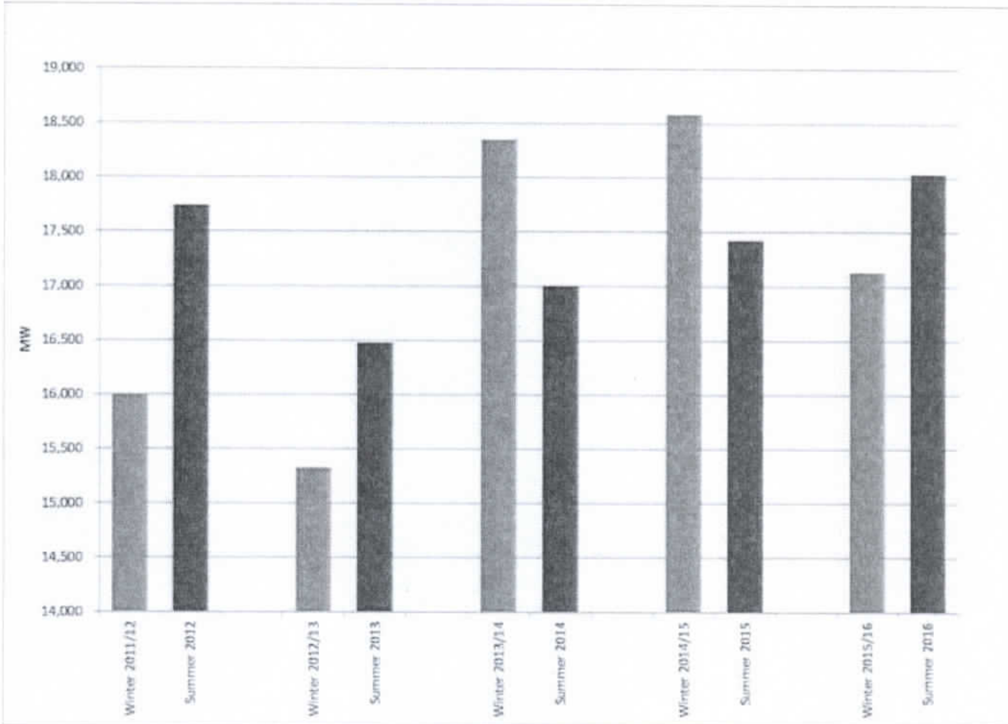
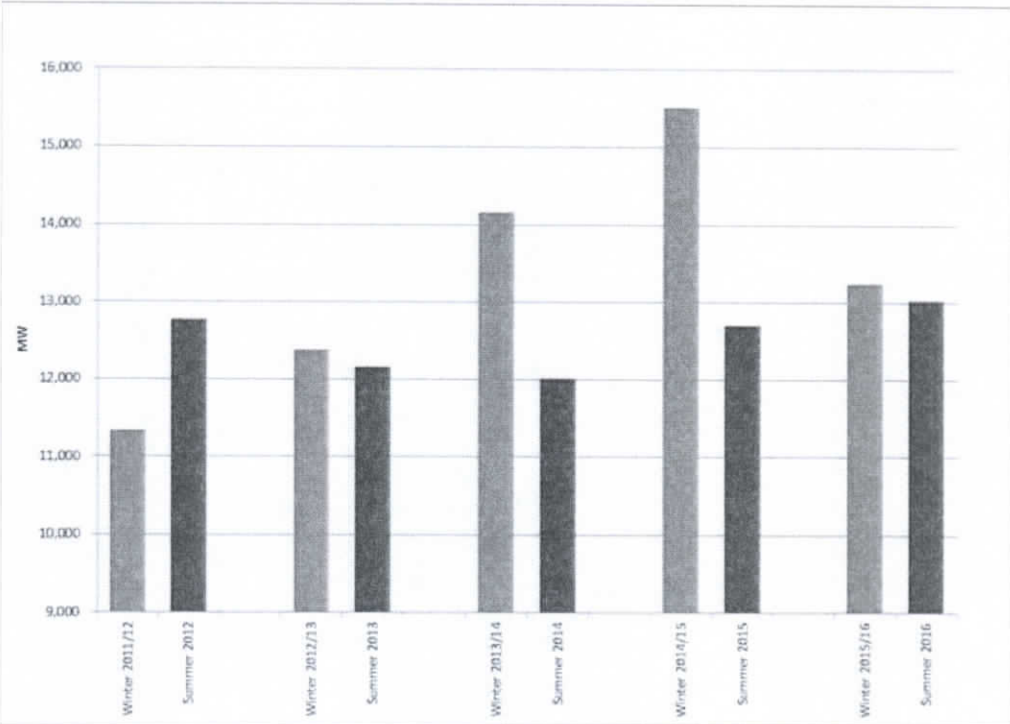



**Figure 13: Historical DEP Winter and Summer Peaks**




**Q. ON A PROJECTED BASIS, DO THE COMPANIES EXPECT THEIR ANNUAL PEAK DEMANDS TO OCCUR IN THE SUMMER OR WINTER?**

A. Based on the Companies' 2016 IRPs, the DEP annual peak is expected to occur in the winter for each year of the planning horizon. However, DEC is summer peaking until around 2027, at which time the annual peak is projected to occur during the winter. For both Companies, the winter peaks are projected to grow a greater rate than summer peaks. Notably, the Companies have experienced significant load response to recent winter weather and are continuing to refine the summer and winter peak demand forecasting process as part of the overall integrated resource planning process.

**Q. DO THE COMPANIES AGREE WITH WITNESS HINTON'S STATEMENT THAT DEC AND DEP WERE MODELED AS WINTER PEAKING IN THE 2016 RESOURCE ADEQUACY STUDIES?**

A. Witness Hinton states, "The third adjustment was to change the seasonal weighting of capacity for summer and non-summer months based on DEP's new reserve margin study that models the Company as winter peaking." [21] However, as I previously stated, based on the 2016 Biennial IRP, DEP's projected winter peaks exceed summer peaks; however, DEC's summer peaks exceed winter peaks until around 2027. The resource adequacy studies were based on study year 2019, when DEP is winter peaking and DEC is summer peaking. Irrespective of summer versus witner peaks, the resource adequacy study results clearly showed the need for both Companies to shift to winter capacity planning as a result of the impact of solar generation.

**Q. NCSEA WITNESS JOHNSON PRESENTS TESTIMONY REGARDING HISTORIC HOURLY LOAD DATA FOR DEC AND DEP FOR THE PERIOD 2006-2015. HOW DO YOU RESPOND TO HIS ASSERTIONS?**

A. Witness Johnson states, "The hourly load data indicates that approximately 86.5% of the most extreme system peaks (at or above 99% of the annual coincident system peak) occurred during the months of June through September, while the remaining 13.5% occurred during the months of

[21] Public Staff Hinton Testimony, at 16.

December, January and February. None of these extreme peaks have occurred during any other months."[22] He concludes that "This data is entirely inconsistent with Duke's proposal to allocate 80% of the capacity costs to a broadly defined non-summer period that starts in October and ends in May." [23]

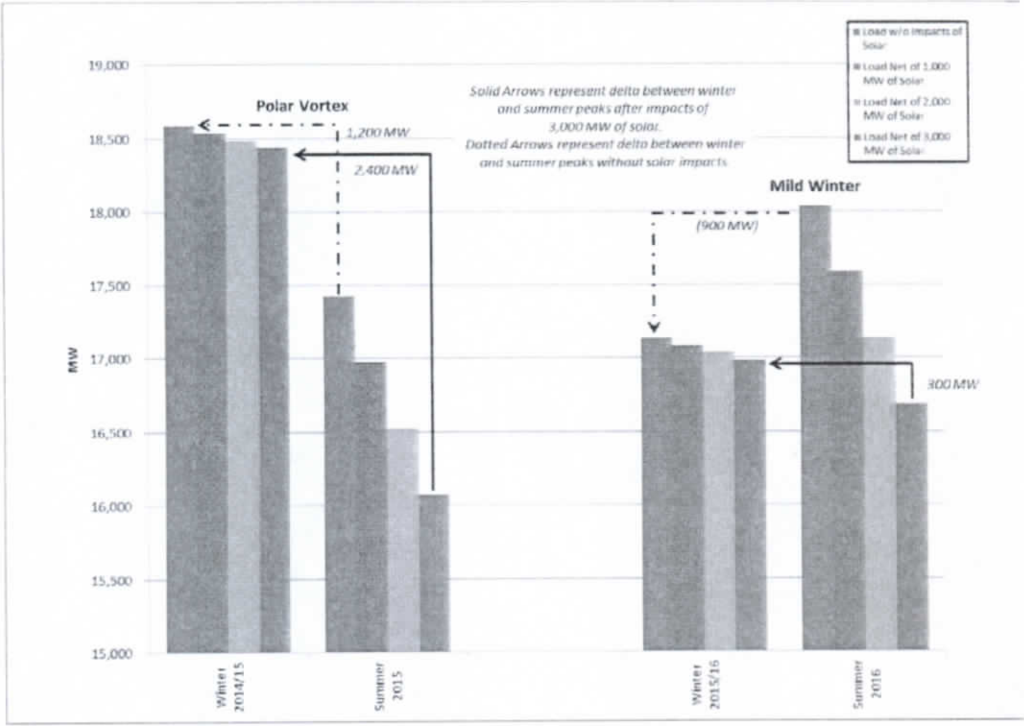
As Witness Johnson points out, the Companies do experience significant summer loads; however, summer peaks occur in late afternoon hours when solar has some energy contributions as compared to winter where very little solar is available at time of peak. Thus, the summer peak loads net of solar output are reduced relative to winter peak loads net of solar. Further, there is greater uncertainty in winter loads as demonstrated during recent winter periods, and these severe winter load and resource conditions have the greatest impact on system reliability and Loss of Load Expectation ("LOLE").

The Companies consider solar resources as supply-side resources in the IRP process. However, for purposes of better understanding the impact of solar on the Companies' summer and winter reserve margins it may be easier to think of solar capacity as a reduction to load. Consider Figure 14 below which shows the relationship of summer versus winter peaks for DEC for a cold winter (2015) and a mild winter (2016). The figure shows the impact on summer and winter peaks for 1,000 MW, 2,000 MW, and 3,000 MW blocks of hypothetical solar capacity. For the 2015 cold winter year, the Figure

[22] NCSEA Witness Johnson Testimony, at 199.
[23] NCSEA Witness Johnson Testimony, at 200.

shows that the winter peak was about 1,200 MW greater than the summer peak. However, 3,000 MW of solar capacity would result in a winter peak that exceeded summer peak by about 2,400 MW. For the 2016 mild winter year, the summer peak exceeded the winter peak by about 900 MW; however, 3,000 MW of solar capacity would actually result in a winter peak that exceeds the summer peak by about 300 MW.

**Figure 14: DEC Historical Peaks including Impacts of Solar Penetration**




The Figure demonstrates the dramatic impact that high penetrations of solar can have on summer versus winter loads (net of solar). This impact on peak demands can also be thought of as the impact on reserve capacity which is the primary driver for the Companies' need to shift to winter capacity planning.

Thus, Witness Johnson only evaluated historic load data and did not consider reserve capacity, which is key to understanding loss of load risk. As I stated, the most severe load and resource conditions typically occur in the winter and these events have the greatest impact on reliability. High solar penetration levels exist today, and evaluating only load data for past time periods is meaningless without consideration of the impact of solar on net reserves. Witness Johnson's argument should be rejected.

**Q. IF SOLAR MAKES SIGNIFICANT CONTRIBUTIONS DURING THE SUMMER, DOESN'T THAT MEAN THAT SOLAR HAS A CAPACITY VALUE?**

A. Existing solar does have capacity value and the impact of solar was captured in the resource adequacy studies that were conducted in 2016. In addition, solar capacity led to the shift to the Companies now planning for a winter reserve margin target that they must now maintain to ensure reliable service to our customers. However, incremental solar additions have little impact on the Companies' future resource needs for maintaining adequate winter reserve capacity. Simply stated, a balanced system only requires so much of a given capacity type. Like any other generation source in the utility's resource mix, the capacity value of incremental solar is less valuable than existing solar.

**Q. THE PUBLIC STAFF RECOMMENDS ADJUSTING THE SEASONAL WEIGHTING TO 40% FOR SUMMER AND 60% FOR NON-SUMMER. DO YOU AGREE WITH THIS RECOMMENDATION?**

A. No. The Public Staff did not directly challenge the rationale of using the loss of load risk in the Companies' resource adequacy studies as the basis to support the seasonal weighting; however, they did express concerns with the seasonal weighting factors of 80/20 winter/summer. Witness Hinton explains the Public Staff's position as:

> . . .the Public Staff does not believe that the significant shift of avoided capacity values to the winter periods should be made at this time. As the Public Staff stated in its comments in the 2016 IRP Proceeding, the shift of DEC and DEP from summer to winter peaking should not diminish consideration of the summer peak, which remains significant. Additionally, Duke is continuing to refine its load forecasting capabilities to better understand the growth and impact of DEC's and DEP's winter and summer peaks. Until a pattern of winter peaks is better understood and there is more confidence that the Company is a winter peaking utility, shifting to a predominantly winter-centric paradigm may be premature. [24]

As I have discussed, the Public Staff seems to base its reasoning incorrectly on the relationship between the Companies' summer versus winter peak demands. While it is true that the Companies have experienced significant peak loads in recent winter periods, and that the Companies continue to refine their load forecasting capabilities and evaluate the growth and impact of winter and summer peak demands, the load forecast (or summer versus winter peaking) is not a primary driver for the significant shift in seasonal loss of load risk. As previously discussed, the primary drivers for the seasonal shift

[24] Public Staff Hinton Testimony, at 25.

in LOLE are the high penetration of solar resources and winter load variability. Both factors can impact actual reserve levels and the resulting LOLE. Additional solar will only exacerbate the winter LOLE concentration. The 40% summer and 60% non-summer seasonal weighting recommended by witness Hinton would send the wrong price signal to developers, and thus the Commission should reject the Public Staff's recommendation.

**Q. SACE WITNESS VITOLO EXPRESSES CONCERN THAT THE RESOURCE ADEQUACY STUDIES OVEREMPHASIZED THE "ATYPICAL" RECENT WEATHER EXPERIENCED DURING THE 2014 AND 2015 WINTERS. WHAT IS YOUR RESPONSE TO WITNESS VITOLO ON THIS ISSUE?**

A. Witness Vitolo states that "... because including all 36 years of historical weather data the study team already had would have both ensured the inclusion of the Polar Vortex years without overly emphasizing them, something including only five years of data did." [25] Witness Vitolo seems to be under the mis-impression that the resource adequacy studies only included the past five years of weather and load data in the analysis. This is not true. In simple terms, the studies included the last five years of weather and load data to develop weather and load relationships that could be applied to all 36 historic weather years (1980-2015) that were included in the study. The resource adequacy studies purpose was to project what the hourly loads would

[25] SACE Witness Vitolo Testimony, at 36.

be for the study year 2019 if the same weather from a historic year was experienced. This modeling was done for all 36 historic weather years, not just the last five.

Load uncertainty due to weather is a key driver of resource adequacy study results. The Companies view the analytics and results produced by Astrape as reasonable and appropriate for utiity planning, and Witness Vitolo's comments should be rejected.

**Q. SACE WITNESS VITOLO ALSO EXPRESSES CONCERNS THAT BASING THE SEASONAL ALLOCATION ON RESULTS FROM STUDY YEAR 2019 MAY NOT BE REPRESENTATIVE OF OTHER YEARS. HOW DO YOU RESPOND?**

A. As Witness Vitolo's notes, the results from the resource adequacy studies conducted in 2016 may not be applicable to all future years since conditions may change that could impact system reliability. The potential for future changes was precisely why the Companies chose to conduct new studies in 2016 in order to account for the impact of significant levels of solar capacity that did not exist and were not foreseen at the time of the 2012 study, as well as the significant response to winter weather that was experienced in the years following the 2012 study. Further, the Companies will continue to commission new studies as significant changes occur that may impact study assumptions and results.

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The recommended 80/20 winter/summer weighting reflects the Companies' best estimates at this time. As I have noted, additional solar will only shift a greater concentration of LOLE to the winter period.

**Q. HAVE THE COMPANIES ASSESSED THE IMPACT OF THE CHANGE IN THE SEASONAL WEIGHTING TO 80% WINTER / 20% SUMMER TO SOLAR QFS?**

A. Yes, we have. This situation is similar to the issue with solar QFs receiving significantly higher capacity payments in relation to the capacity value they provide due to the broad range of on-peak hours defined in Option B. The Companies have determined that the net impact on capacity payments paid to solar QFs as a result of changing the seasonal weighting to 80/20 winter/summer (i.e. 80/20 non-summer/summer) is negligible. Depending on whether the DEC or DEP solar profile is used, the impact on capacity payments is about +/- 1%. Thus, while the change in seasonal weighting is significant, the impact on avoided capacity payments to solar QFs in this docket is quite small. Finally, for a baseload QF, such as a cogenerator, there would be no impact on capacity payments.

**Q. IF SOLAR PROVIDES A 5% CAPACITY VALUE RELATIVE TO ITS NAMEPLATE RATING, TO WHAT EXTENT ARE THE COMPANIES' STANDARD OFFER AVOIDED CAPACITY RATES DESIGNED TO COMPENSATE FOR THE NAMEPLATE CAPACITY?**

A. As I have noted, given the broad definition of on-peak hours in the current Schedule PP Option B rate structure, a typical solar facility would be compensated for avoiding approximately 40% of its nameplate capacity in equivalent avoided "peaker" capacity while only providing an actual capacity value of about 5%. This means that each MW of QF solar would be compensated for almost 40% of the cost of a MW of a CT beginning with the first need for new capacity while providing only 5% of the capacity value that a CT would provide. This result is also prior to any PAF adjustment.

**Q. DOES THE CHANGE IN SEASONAL CAPACITY VALUE ALLOCATION TO 80/20 WINTER/SUMMER HAVE A SIGNIFICANT IMPACT ON THE CAPACITY PAYMENT TO SOLAR FACILITIES UNDER THE COMPANIES' RATES IN THIS PROCEEDING?**

A. No, it does not.

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

A. Yes, it does.

BY MS. FENTRESS:

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

A (MR. SNIDER) Yes, I do.

Q Would you please present that for the Commission?

A Yes, thank you.

(WHEREUPON, the summary of **GLEN A. SNIDER** is copied into the record.)

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
Summary of Glen Snider's Direct and Rebuttal Testimony
NCUC Docket No. E-100, Sub 148

My Direct Testimony supports the Companies' filed avoided cost energy and capacity rates and the underlying calculation methodology. I provide an overview of the filed rates, as well as a comparison of rates in the two previous biennial avoided cost proceedings. With respect to avoided energy cost rates, I discuss relevant market developments since the 2014 proceeding, including the decreases in the cost of natural gas and coal. With respect to avoided capacity cost rates, I explain that they have decreased primarily because the Companies do not have an actual capacity need during the initial years of the proposed 10-year contract period. Finally I explain that a solar specific qualifying facility ("QF"), taking service under the Companies' general QF rates is overcompensated for capacity value when the specific attributes of a solar QF are taken into account. My Direct Testimony also addresses the financial impacts of existing Public Utility Regulatory Policy Act ("PURPA") contracts on our customers. As explained by the Companies' Witnesses Yates and Bowman, the Companies believe that the State is at a solar development crossroads. The recent, rapidly changing economic and market circumstances, which include the surging growth in long-term QF fixed price contracts, has been a primary driver of the Companies' proposed modifications to the standard offer rate structures in this proceeding. Focusing on only the 1,600 MW of existing solar QF purchase power agreements ("PPAs") for installed solar QFs of 1 MW and greater as of the end of 2016, I estimate an approximate $2.9 billion existing obligation for our customers over the remaining terms of these agreements. If those contracts were valued at current market conditions, as represented in the Companies' most recently filed avoided cost rates, they would have a value of only $1.9 billion, which puts our customers at risk for a potential long-term overpayment of $1.0 billion. I then discuss additional financial exposure from an incremental 1,100 MW of solar QF projects currently in the Companies' interconnection queues that have established Sub 136 or Sub 140 legally enforceable obligations ("LEOs"), making them eligible for now stale and significantly higher previously approved avoided cost rates.

I further explain how a maximum 10-year contract that provides fixed capacity rates over the 10-year term, with energy rates adjusted every two years, benefits our customers because a structure that adjusts energy rates at reasonable, periodic intervals through the duration of a long-term contract is an effective way to reduce customers' exposure to the risk of overpayment. With respect to avoided capacity, I explain how the filed 10-year rates provide a payment in each year of the QF contract utilizing a valuation methodology that ascribes value starting with the first year of an actual incremental need for capacity. The Companies' 2016 integrated resource plans ("IRPs"), indicate the first capacity needs occur in 2022 and 2023 for Duke Energy Progress ("DEP") and Duke Energy Carolinas ("DEC") respectively. I also support the utilization and justification of a 1.05 Performance Adjustment Factor ("PAF") which is an on-peak availability multiplier applied to the capacity rate. I demonstrate that lowering the PAF from the previous level of 1.2 to 1.05 is justified to ensure that a QF operating with an availability equivalent to that of traditional utility generation receives the full appropriate non-discriminatory capacity value without creating an overpayment for customers.

Finally, I address why it is essential for the Commission to recognize changing economic and market conditions and to adopt the Companies' filed rates in order to ensure that the central "but for" principle underpinning PURPA is upheld. The "but for" principle requires that avoided costs should reflect the costs of energy and capacity that would have otherwise been incurred by a utility *but for* the purchase from a QF. This is necessary to ensure that residents, businesses and industries in North Carolina do not pay more for future QF power than they would have if that power was delivered from traditional resources.

My Rebuttal Testimony addresses arguments of various parties that the Commission should raise both the avoided energy and avoided capacity rates, as well as extend the fixed price term of those rates. In my view, the magnitude of the risk of overpayment by our customers is a significant factor facing the Commission and the State. While I individually address the issues raised by these various parties, I believe it is critically important not to lose sight of the overall impact of the energy and capacity value of QF power, and QF solar power, in particular. I point out in my rebuttal testimony that the previous 10-year annualized energy rate that went into effect on March 1, 2016 pursuant to the Sub 140 order averaged \$42.80 per Megawatt-hour ("MWh") while the actual system marginal costs for the Companies dropped from \$33.65/MWh in 2015 to \$29.16/MWh in 2016. I go on to explain that the Companies' proposals in this proceeding are intended to mitigate the level of overpayment risks that ultimately get passed on to North Carolina consumers.

With regard to specific intervener issues impacting the avoided energy rates, I address the two-year reset of energy prices vs. 10-year fixed prices; the use of market prices vs. fundamental fuel prices; the merits of a solar only energy rate; and the impact of line losses and ancillary costs in calculating standard offer avoided cost rates.

First, in response to the argument that resetting energy prices every two years will not allow QF projects to obtain financing, I point out that nothing in PURPA requires states to approve price levels high enough to attract financing. To address concerns that small QFs may not be able to attract financing, however, the Companies present a compromise proposal that allows small QFs to "fix" the energy rate for the full 10-year term as described in Witness Bowman's rebuttal testimony.

With respect to arguments against the use of 10-year forward prices in the calculation of avoided energy rates, I explain that long-dated forward contracts are liquid and transactable, and that DEP was able to demonstrate this liquidity through a 10-year purchase of a natural gas forward position. Additionally, I point out that the use of fundamental forecasts in calculating the avoided energy rate would lead to an immediate and extremely significant overpayment risk for customers; and that the use of fundamental price forecasts rather than actual market prices would create an inconsistency between purchasing power using fundamental forecasts while purchasing gas at market prices. Finally I explain that the current IRP methodology is reasonable and appropriate for both resource planning and for setting avoided energy rates and complies with the Commission's order to ensure consistency in fuel price methodology between IRP and avoided cost filings.

With respect to a solar-only energy rate, the Companies support consideration of moving towards a solar-specific avoided energy rate for larger QFs. Such a move, using a solar-specific load profile to calculate negotiated QF rates, would provide price signals to QFs that reflect the specific characteristics of the QF, as PURPA envisioned. Further, the Companies agree that elimination of DEP's line loss adder and the inclusion of ancillary costs should be considered in future avoided cost proceedings.

I also address concerns about changes to components of the capacity rate valuation. With respect to recognizing capacity value starting with the first year of actual need, I agree with Public Staff Witness Hinton that to include capacity value that is not actually avoidable would result in overpayment by customers, in violation of PURPA. I disagree with NCSEA Witness Johnson, who mistakenly assumes that utilities overbuild generation. He fails to recognize that the selection of a generating resource is made after careful consideration of the costs and benefits of smaller versus larger units.

With respect to concerns about reducing the Performance Adjustment Factor, I explain that a PAF of 1.05 aligns the capacity payment adder to the correct reliability metric and thus fairly compensates a standard-offer QF for the capacity value it provides. I point out that the Public Staff incorrectly used an annual availability metric, rather than a peak period availability metric to support a recommended PAF of 1.16. I explain that QFs are not held to an annual availability standard but only a peak period availability standard. As such, a more appropriate availability metric for Public Staff to consider is the Equivalent Forced Outage Rate ("EFOR"), which better represents the on-peak reliability of utility generation. While reducing the PAF to

1.05 would require QFs, which are not dispatchable, to operate during 95% of their on-peak hours to receive the full capacity payment, the Companies' fleet operates at an availability level above 95% of its on-peak hours. Finally, with respect to the PAF, I explain an important distinction, pointing out that if QFs were actually dispatchable, a rate structure could be developed that would compensate for capacity based on a facility's ability to deliver power when called upon.

With respect to seasonal weighting, I clarify that "winter capacity planning" is not the same as "winter peaking" and explain that the 2016 resource adequacy studies clearly show the need for both Companies to shift to winter capacity planning as a result of the impact of solar generation. The most severe load and resource conditions typically occur in the winter, and these events have the greatest impact on reliability. Although existing solar resources have a capacity value, incremental solar additions will have little impact on future resource needs to maintain adequate winter reserve capacity.

In response to SACE Witness Vitolo's concerns that the 2016 resource adequacy studies over-emphasize the "atypical" winter weather in 2014 and 2015, I point out that 36 years of weather data were included in the studies' modeling. In fact, the Companies chose to conduct new studies to account for the impact of both severe weather and significant levels of solar capacity that were unforeseen in 2012. Further, the Companies have determined that the net impact on capacity payments paid to solar QFs as a result of changing the seasonal weighting is negligible under the current definition of on-peak hours.

Finally, throughout my Rebuttal Testimony I explain that although the QF rates filed by the Companies in this proceeding are just and reasonable for a generic QF technology, they overstate the value relative to a solar specific rate, because incremental solar generation is no longer coincident with the Companies' capacity needs nor is a solar QF producing power that is coincident with the Companies' highest cost marginal energy periods.

This concludes my summary.

MS. FENTRESS: Thank you, Mr. Snider. After presentation of the rest of the panel, Mr. Snider will be available for cross. I'd now like to move to Ms. Bowman.

DIRECT EXAMINATION

BY MS. FENTRESS:

Q Good morning, Ms. Bowman.

A (MS. BOWMAN) Good morning.

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

A My name is Kendal Bowman. My business address is 410 South Wilmington Street, Raleigh, North Carolina.

Q Ms. Bowman, by whom are you employed and in what capacity?

A I'm employed by Duke Energy and I am Vice President Regulatory Affairs and Policy for North Carolina.

Q Thank you. And did you cause to be prefiled in this docket on February 21st of this year 61 pages of direct testimony?

A Yes.

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.

MS. FENTRESS: Mr. Chairman, at this time I would move that the direct testimony of Ms. Bowman be copied into the record as if given orally from the stand?

CHAIRMAN FINLEY: Ms. Bowman's direct testimony filed on February 21, 2017, consisting of 61 pages is copied into the record as though given orally from the stand.

MS. FENTRESS: Thank you.

(WHEREUPON, the prefiled direct testimony of **KENDAL C. BOWMAN** is copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

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| In the Matter of<br>Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016 | )<br>)<br>)<br>)<br>) | **DIRECT TESTIMONY OF KENDAL C. BOWMAN ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC** |

## I. INTRODUCTION AND PURPOSE

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

A. My name is Kendal Crowder Bowman. My business address is 410 South Wilmington Street, Raleigh, NC 27601.

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

A. I am employed as Vice President Regulatory Affairs and Policy North Carolina for Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively the "Companies"), which are wholly owned subsidiaries of Duke Energy Corporation ("Duke Energy").

**Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A. I have a Bachelor of Science in Psychology from the University of Virginia and a Juris Doctor from Stetson University College of Law. I began my professional work experience in 1997 as an attorney for Florida Power Corporation in St. Petersburg, Florida. In 1999, I joined Carolina Power & Light Company as an associate general counsel. Shortly after I joined Carolina Power & Light Company, it merged with Florida Power Corporation and became Progress Energy. After the close of that merger, I was Progress Energy's attorney for Federal Energy Regulatory Commission ("FERC") matters for all regulated utilities and our unregulated merchant generation operations. Upon Progress Energy's exit from the unregulated merchant generation business in the early 2000s, I led Progress Energy's legal federal regulatory affairs group and was responsible for FERC legal, policy, and compliance matters for Progress Energy Carolinas and Progress Energy Florida. In 2010, I transitioned from FERC work to state regulatory legal work for Progress Energy Carolinas in both North Carolina and South Carolina. Following the merger between Duke Energy and Progress Energy, I became Deputy General Counsel supporting all legal state regulatory functions for North Carolina. In February 2013, I was named to my current role with Duke Energy Corporation.

**Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES AS VICE PRESIDENT REGULATORY AFFAIRS AND POLICY FOR NORTH CAROLINA?**

A. I am responsible for managing North Carolina regulatory matters and directing North Carolina energy policy for DEC and DEP.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. My testimony generally addresses the Companies' experiences with the implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA") in North Carolina up to the present. I explain how today's economic and regulatory circumstances necessitate a comprehensive review of PURPA implementation in North Carolina, due to the unprecedented growth of solar qualifying facilities ("QFs") in the Companies' service territories since the Commission's previous avoided cost proceeding in Docket No. E-

100, Sub 140 ("Sub 140"). In conjunction with Witnesses Lloyd M. Yates, Glen A. Snider, and J. Samuel Holeman, my testimony describes the impact that this recent rapid growth in QF solar development has had on the Companies and our customers.

I next testify about the Companies' proposals to evolve the Commission's current PURPA standard offer policies to reflect these evolving economic and regulatory circumstances and to assure the Companies' avoided cost rates are just and reasonable to our customers and consistent with the public interest and North Carolina's energy policies. These recommended modifications include:

- Lowering the eligibility limit for the Companies' standard avoided cost rate tariffs from 5 megawatts ("MW") to 1 MW for non-hydroelectric generators;
- Transitioning to a single, 10-year long-term standard contract with fixed, levelized capacity rates and energy rates that are adjusted by the Commission every 2 years to better mitigate the significant risks of overpayment by customers compared to current avoided costs, as recently experienced under the Sub 140 15-year fixed long-term contracts;
- Reducing the Performance Adjustment Factor ("PAF") from 1.2 to 1.05 to more precisely reflect the reliability of a Combustion Turbine, as addressed by Witness Snider;

- Amending the Companies' Terms and Conditions to include circumstance that requires action by the Companies to comply with North American Electric Reliability Corporation ("NERC")/SERC Reliability Corporation ("SERC") regulations as an "an emergency condition;"
- Amending the Companies' standard Power Purchase Agreements ("PPAs") to ensure that the Commission's eligibility threshold for the standard offer is not evaded by subsequent transfers of standard PPAs to a partner or affiliate of a developer of another QF of the same energy resource located within one-half mile; and
- Modifying the Commission's current implementation of the Legally Enforceable Obligation ("LEO") concept under PURPA by requiring QFs to make a legally enforceable commitment to sell in order to obligate customers to purchase from QFs, thereby more appropriately allocating the risk of non-performance to QFs and better aligning the avoided cost rates paid to the QF with the value received by our customers.

Finally, I discuss how the Companies' proposals represent an important and necessary first step in a transition to a more "well-planned and coordinated" process that balances PURPA's goal of encouraging QF development with the dual challenges of integrating solar into our system and aligning the costs our customers are ultimately paying for solar QF power with the value they are receiving.

## II. PURPA IMPLEMENTATION IN NORTH CAROLINA

**Q. PLEASE PROVIDE THE COMMISSION WITH AN EXPLANATION OF PURPA AND ITS PURPOSE.**

A. PURPA was enacted in 1978 in response to the mid-1970s energy crisis, to promote conservation of oil and natural gas by electric utilities, thereby lessening the country's dependence on foreign oil, and ultimately intending to control costs for consumers. Title II of PURPA, specifically Section 210, also established a new policy of encouraging development of non-utility owned cogeneration and small power production facilities. Section 210 of PURPA was largely driven by concerns that traditional electric utilities during the 1970s were reluctant to purchase power from and to sell power to these nontraditional facilities.[1] To encourage development of these new wholesale power generators, Congress mandated that they should have the right to sell power to and purchase back-up power from traditional utilities, and also should be exempt from certain financial and rate regulation burdens imposed on traditional public utilities, effectively exempting these generators from federal or state regulatory oversight of their books and cost of service. Thus, from PURPA's initial enactment, Congress provided significant "regulatory

[1] *FERC v. Mississippi*, 456 U.S. 742, 750 (1982).

encouragement" of cogeneration and small power production facilities compared to traditional fully-regulated public utilities. However, Section 210 was also expressly focused on controlling costs for consumers, requiring utilities to purchase power from cogenerators and small power production facilities at non-discriminatory rates that are just and reasonable to the utility's customers and in the public interest.

Congress directed FERC to develop regulations to implement PURPA, but, in doing so, explicitly forbade such rules from requiring a utility to pay a rate that would exceed the incremental cost of its alternative options of generating or purchasing electric energy, *i.e.*, the cost to the utility which "but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[2] In other words, it is the purchasing utility's incremental or "avoided" cost that PURPA requires to be paid, which ensures customers remain "indifferent" between the costs of utility or non-utility generation. Thus, on its face, Section 210's encouragement of cogeneration and small power production facilities provides QFs a right to sell at rates that are "just and reasonable to the electric consumers . . . and in the public interest" but has never expressed a legislative intent to subsidize this new class of non-utility generators.

[2] 16 U.S.C § 824a-3(b); (d).

**Q. IN ENACTING SECTION 210 OF PURPA, HOW DID CONGRESS PRESCRIBE FERC'S ROLE AND THE COMMISSION'S ROLE?**

A. Section 210 of PURPA established a program of "cooperative federalism"[3] under which Congress directed FERC to promulgate regulations to implement PURPA, while state regulatory authorities, such as the Commission, and non-regulated utilities are ultimately responsible for state-by-state PURPA implementation in conformance with FERC's regulations.

In 1980, FERC's Order No. 69 established regulations to implement PURPA.[4] Under FERC's regulations, cogenerators and small power producers, collectively called "Qualifying Facilities" were granted new rights to interconnect to the electrical grid and to sell their output to traditional utilities in the wholesale marketplace. Specific to the utility's obligation to purchase from QFs, FERC's regulations provide that rates for purchases from QFs shall be just and reasonable to the electric consumer of the electric utility and in the public interest; shall not discriminate against the QF, and shall not require the utility to pay more than its "avoided costs" for purchases. In implementing these requirements, FERC mandated that small QF generators of 100 kW or less be offered standard avoided cost rates, while leaving it to

[3] *See, e.g.,* Memorandum of Agreement between the Federal Energy Regulatory Commission and the Idaho Public Utilities Commission at 2 (Dec. 24, 2013) (explaining that PURPA established a program of cooperative federalism where State Commissions are responsible for implementing PURPA and may do so "in a manner that accommodates local conditions and concerns so long as the implementation is consistent with PURPA and the FERC's regulations implementing PURPA.").

[4] *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶30,128, (1980) ("Order No. 69").

the implementing State Commission to determine whether to offer standard avoided cost rates to generators greater than 100 kW.

As explained in Order No. 69 and subsequently in FERC's 1983 Policy Statement, PURPA delegates to State Commissions and non-regulated public utilities the responsibility of implementing PURPA's "must purchase" requirements, so long as the State's implementation is reasonably consistent with the regulations established by FERC.[5] State Commissions are afforded "great latitude" in determining State PURPA policies because they are best suited to consider and balance PURPA's goals with the "economic and regulatory circumstances [that] vary from State to State and utility to utility."[6]

**Q. PLEASE NOW DESCRIBE NORTH CAROLINA'S APPROACH TO IMPLEMENTING PURPA'S "MUST PURCHASE" REQUIREMENTS.**

A. In 1979, the General Assembly enacted N.C. Gen. Stat. ("G.S.") § 62-156 to implement PURPA for hydroelectric generators no larger than 80 MW. Since 1981, North Carolina has generally followed a hybrid approach to implementing the PURPA "must purchase" requirements, which includes biennial review of utility avoided costs for smaller QFs (both hydro and non-hydro) eligible for tariffed "standard offer" avoided cost rates and terms and conditions approved by the Commission, while allowing the State's electric utilities to negotiate with larger QFs not eligible for the standard offer to

[5] *Order No. 69* at 7; *see also, Policy Statement Regarding Comm'n's Enforcement Role Under Sec. 210 of the Public Utility Regulatory Policies Act of 1978*, 23 FERC ¶ 61,304, 61,644 (1983).

[6] *Order No. 69* at 93-94.

establish avoided cost rates. The current proceeding is the 16th biennial proceeding held by the Commission to implement PURPA's must purchase requirements and to establish avoided cost standard offer rates for smaller QFs.

**Q. HOW HAS THE COMMISSION EVOLVED ITS IMPLENTATION OF PURPA AS ECONOMIC AND REGULATORY CIRCUMSTANCES HAVE CHANGED OVER TIME IN NORTH CAROLINA?**

A. Over the past 35 years, the Commission has exercised the flexibility afforded by FERC's regulations in setting North Carolina's PURPA policies. Beginning with the Commission's initial proceeding implementing PURPA in 1981, the Commission has applied its expert judgment to balance encouragement of QF development with achieving the public interest and mitigating potential harm to ratepayers through setting just and reasonable PURPA rates and policies. In balancing these various interests, the Commission has considered changing economic and regulatory circumstances affecting each utility as well as North Carolina's energy policies, as set forth in the Public Utilities Act.[7]

The Commission has significantly evolved its standard contract policies since the 1980s. In its initial 1981 Order implementing PURPA's

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[7] *See, e.g., Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 10, Docket No. E-100, Sub 100 (Sept. 29, 2005) (explaining that offering long-term standard avoided cost rates is "an issue that the Commission must continually reconsider as economic circumstances change from one biennial proceeding to the next . . . [and] must balance the need to encourage QF development on the one hand and the risks of overpayments and stranded costs, on the other.").

avoided cost policies, the Commission required DEC (then Duke Power Company or "Duke") and DEP (then Carolina Power & Light or "CP&L"), to offer long-term, levelized standard contracts of up to 15-year terms for all QFs, regardless of size. In contrast, the Commission did not require Dominion North Carolina Power ("DNCP") to provide QFs above 100 kW with any long-term levelized standard contract offerings due to the significant ongoing development of cogeneration and small power production facilities in DNCP's service territory in the early 1980s.

In 1985, the Commission deviated from past practice and evolved its standard contract policies to require all three utilities – Duke, CP&L, and DNCP – to offer all non-hydro QFs of 5 MW or less with standard long-term levelized avoided cost rate options up to 15 years in length while allowing larger QFs to negotiate PURPA PPAs with the utilities based upon their respective avoided costs.[8] In balancing the interests of QFs, the utilities, and customers, the Commission adopted the 5 MW standard offer eligibility cap because the default risks associated with such smaller QFs was "relatively small in terms of dollar exposure and impact on supply" when compared to larger QF projects and because, at that time, these smaller QF projects would "probably not have the resources or the expertise to negotiate a contract with a utility if these standard options were not available."[9]

[8] *Order Establishing Levelized Rates for Cogenerated Power and Maintaining Interconnection and Wheeling Policies*, Docket No. E-100, Sub 41A (Jan. 22, 1985).

[9] *Id.*

Since 1985, the Commission has adjusted the utilities' PURPA rates and standard contract offerings on a number of occasions in response to evolving economic, regulatory, and policy developments. For example, in the late 1990s, the Commission limited the 5 MW cap on long-term levelized rates to only include trash, landfill gas, and animal waste fueled facilities in recognition of State policies supporting development of these technologies.[10] During this time, CP&L emphasized that its 15-year avoided cost projections from the early 1980s had "grossly overstated actual avoided costs, resulting in overpayments for the purchase of power from QFs" while Duke highlighted increased future risk of overpayment due to "the increasingly competitive nature of the utility industry."[11] In approving the continued availability of long-term 15-year standard contracts for certain QFs up to 5 MW in size, the Commission again emphasized in its 1996 biennial avoided cost order in Docket No. E-100, Sub 79, that future exposure to overpayments was limited because QFs "entitled to long-term rates are generally of limited number and size." From 1996 through the early 2000s, the Commission limited solar and wind QFs standard offer eligibility to a 5-year contract option for generators up to 3 MW in size.[12] In 2004, the Commission expanded the technologies eligible for the favored 5 MW 10- and 15-year standard term options to

[10] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 9, Docket No. E-100, Sub 79 (June 19, 1997).

[11] *Id.* at 10-11.

[12] *See, e.g., Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 8-9, Docket No. E-100, Sub 81 (July 16, 1999); *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 11-12, Docket No. E-100, Sub 96 (Oct. 29, 2003).

include solar, wind, and non-animal biomass, finding that encouraging development of QFs fueled by these technologies serves the public interest.[13] Since 2005, the Commission's implementation of the PURPA standard offer has remained relatively unchanged, continuing to significantly encourage QF development by offering renewable generators up to and including 5 MW standard rate options up to a 15-year term.

The history of PURPA implementation in North Carolina recognizes that the Commission has applied its broad authority to modify PURPA standard offer implementation in response to evolving economic, regulatory and policy developments.

## III. TODAY'S ECONOMIC AND REGULATORY CIRCUMSTANCES NECESSITATE COMPREHENSIVE REVIEW OF PURPA IMPLEMENTATION IN NORTH CAROLINA

**Q. PLEASE DESCRIBE THE CURRENT ECONOMIC AND REGULATORY CIRCUMSTANCES NECESSITATING COMPREHENSIVE REVIEW OF PURPA IMPLEMENTATION.**

A. As introduced in the Companies' Joint Initial Statement, North Carolina's utility-scale solar development success is driving the need for comprehensive review of the Commission's PURPA policies. While North Carolina's PURPA policies have remained relatively unchanged over the past decade, economic and regulatory circumstances – both in North Carolina and around

[13] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 11, Docket No. E-100, Sub 100 (Sept. 29, 2005).

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the country – have changed drastically in a very short period of time. Beginning in 2013, the Companies increasingly began to highlight the potential impacts of utility-scale solar on future operations and the need to carefully evaluate these new and potentially significant economic and regulatory circumstances in setting future just and reasonable PURPA policies for North Carolina. In joint comments filed in the Sub 136 Proceeding in March 2013, the Companies stated that

> . . . the integration of intermittent resources, such as solar and wind, is an issue of growing importance. The electric industry is only beginning to understand the costs, benefits, and challenges associated with these types of resources. A resource that is available on a limited and unpredictable basis has a much different impact on system operations and reserve requirements than one that it is dispatchable and generally available. For example, from the perspective of what capacity costs such resources allow a utility to avoid, traditional and intermittent resources have significantly different values. In light of the significant, ongoing upsurge in the amount of intermittent resources being proposed and recently certificated for construction in North Carolina, it may be the appropriate time for the Commission, the Utilities and other stakeholders to consider these issues.[14]

The Commission's February 21, 2014 Order in Sub 136 similarly recognized the need to evaluate "the potential magnitude of the impacts on generation, transmission, and distribution systems of both smaller distributed and utility-scale solar photovoltaic projects that are proposed to be constructed in North Carolina" including "the potentially disruptive implications, both positive and

[14] *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2012*, Duke Energy Carolinas and Progress Energy Carolinas Joint Reply Comments at 39, Docket No. E-100, Sub 136 (May 13, 2013).

negative, of this changing landscape."[15] In the Companies' view, these rapidly changing economic and regulatory circumstances have caused the Commission's continuation of its historic polices going forward to no longer be just and reasonable to the Company's customers or to serve the public interest.

The Companies believe the following economic and regulatory circumstances should now be considered by the Commission in this proceeding to begin a transition of North Carolina's energy landscape towards a smarter, more sustainable, and reliable future:

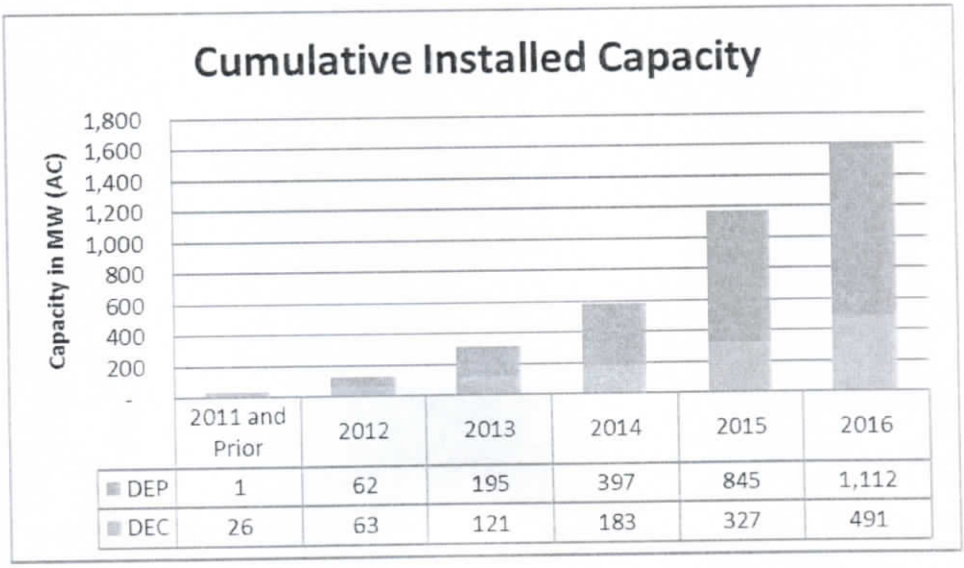
1) PURPA's role in the recent surging and uncontrolled growth of utility-scale solar, including the significant long-term financial obligations now being imposed on the Companies' customers;
2) The broader regulatory context of national PURPA implementation and the cost implications for customers should North Carolina continue to maintain the status quo in future PURPA standard offer implementation; and
3) The mandates of North Carolina's energy policies set forth in the Public Utilities Act should also be recognized in evaluating the public interest and balancing PURPA's goal of encouraging QF development with current economic and regulatory circumstances.

[15] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 31, Docket No. E-100, Sub 136 (Feb. 21, 2014).

**Q. PLEASE UPDATE THE COMMISSION ON THE CURRENT STATE OF SOLAR DEVELOPMENT IN THE COMPANIES' NORTH CAROLINA SERVICE TERRITORIES AS OF DECEMBER 31, 2016.**

A. In only five years, installed utility-scale solar capacity has increased dramatically in DEC and DEP from approximately 125 MWs in 2012 to 1,600 MWs (approximately 1,100 MWs installed in DEP and 500 MWs installed in DEC, respectively). Figure 1 depicts year-over-year growth in installed solar Photovoltaic ("PV") capacity in DEP and DEC between 2011 and December 31, 2016.

**Figure 1**



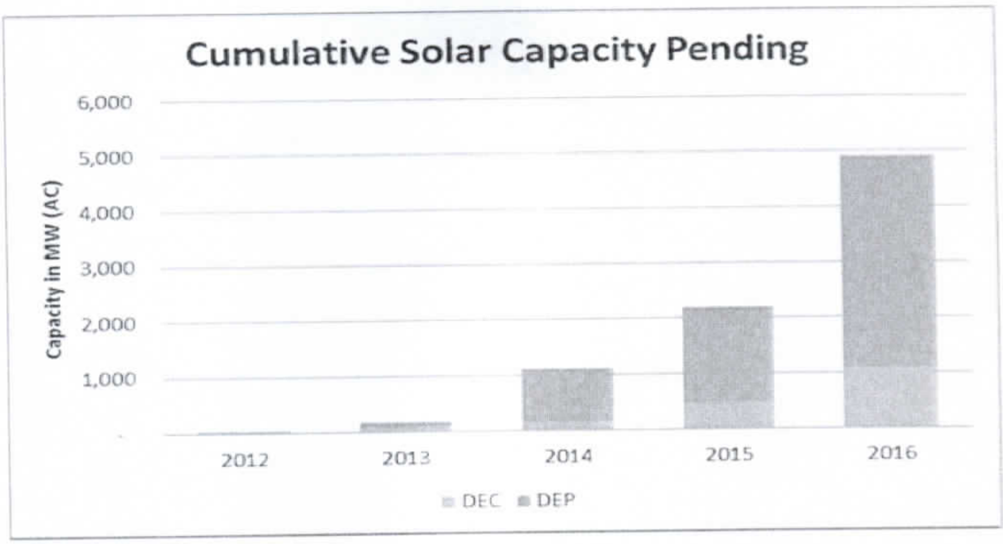

*Reflects 3rd Party-Owned Installed Nameplate (AC) Solar Capacity located in North Carolina only.*

The 2016 installed capacity growth presented in Figure 1 also reflects an additional 285 MWs of projects that have now been interconnected and have begun selling power to the Companies (approximately 150 MWs in DEP and

135 MWs in DEC, respectively) since September 30, 2016, as reported in the Companies' Joint Initial Statement.

Even more significant is the level of ongoing PURPA-driven solar development in North Carolina today. As of January 1, 2017, an additional approximately 4,900 MWs of proposed solar projects are either under construction or are in development and requesting to interconnect and sell power to the Companies (approximately 3,800 MWs in DEP and 1,100 MWs in DEC, respectively). The increase in the development of solar capacity is shown in Figure 2 below:

**Figure 2**




**Q. PLEASE DESCRIBE THE DRIVERS OF THIS SURGING SOLAR GROWTH IN NORTH CAROLINA OTHER THAN PURPA.**

A. As described in Section II.a of the Companies' Joint Initial Statement, a number of policy drivers have contributed to the surging solar growth in North

Carolina. In 2007, our State was first in the Southeast to enact a renewables portfolio standard. Senate Bill 3 contemplated that the Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") would be met through a diverse portfolio of traditional renewable resources, such as hydropower, biomass and landfill gas, as well as integration of new (and traditionally not cost-effective) renewable energy resource technologies, such as wind and solar. To help spur solar development in the State, the General Assembly also enacted a specific state policy, G.S. § 62-133.8(d), mandating that each electric power supplier should begin procuring solar for REPS compliance by 2010 and should meet at least 0.20% of their retail load using solar by 2018 (the "NC Solar Set-Aside"). This NC Solar Set-Aside was important at the time as the installed cost of utility-scale solar PV was significantly higher than other more mature renewable technologies.[16]

Federal and State tax credit policies supporting solar development have also been significant. In December 2015, Congress authorized extension of the 30% Federal solar investment tax credit incentive ("ITC"). The current Federal ITC now extends through at least 2019 before it steps down to 10% after 2021.[17] In North Carolina, in addition to REPS, the 35% Renewable Energy Tax Credit ("RETC") also provided significant additional financial

[16] *See* La Capra Associates, Inc., Technical Report: Analysis of a Renewable Portfolio Standard for the State of North Carolina, Prepared for the North Carolina Utilities Commission (December 2006) at 36 (solar PV deployment "is not limited by technical or practical considerations but rather by current levels of installed costs.").

[17] 16 U.S.C. § 48(a)(6).

incentive to promote solar development in the State.[18] Although the RETC expired at the end of 2015, the State enacted a "safe harbor" in April 2015 to provide projects in advanced stages of development until December 31, 2016, to complete development and be placed in service.[19]

Notably, as highlighted in Section II.a. of the Companies' Joint Initial Statement, the average installed cost of utility-scale solar has also declined nearly 80% in the last decade.

**Q. WITH THE EXPIRATION OF THE STATE'S RETC FOR NEW PROJECTS IN 2015, IS NORTH CAROLINA NOW ON A LEVEL PLAYING FIELD WITH OTHER STATES IN TERMS OF SOLAR POLICY SUPPORT?**

A. While each State has enacted their own energy policies, some of which include promoting solar and other renewable energy development in various ways, the RETC's expiration eliminated a significant financial incentive supporting solar development in North Carolina compared to other States. In contrast, Congress' extension of the Federal ITC as well as the significant decline in the installed cost of building utility-scale solar apply equally across all States.

Additionally, financial policy support of North Carolina solar development through REPS has also declined significantly over the past few

[18] G.S.§ 105-129.15 *et seq.*

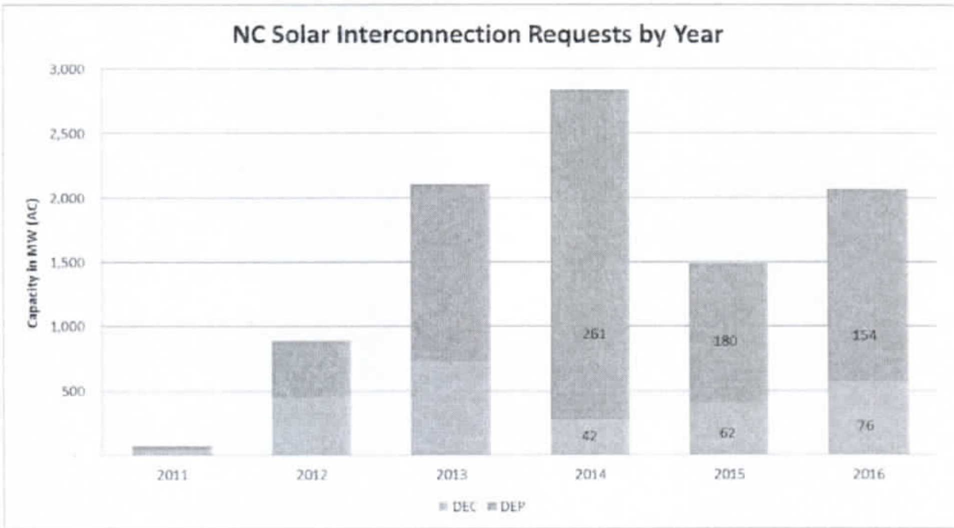
[19] *See* Session Law 2015-11, enacting G.S. § 105-129.16A.

years as the supply of solar renewable energy credits ("RECs") has increased significantly and is now outpacing electric power suppliers' demand for solar RECs. DEC and DEP both currently have enough solar RECs to meet the NC Solar Set-Aside compliance beyond 2030. These excess solar RECs are also helping both Companies meet their general REPS compliance obligations for the foreseeable future. DEP has currently contracted for sufficient RECs to meet its general REPS compliance obligations through 2028, while DEC will be able to meet its general REPS compliance obligations through 2019 (after including 300 MWs procured through DEC's 2016 RFP solicitation).

**Q. IF NORTH CAROLINA IS NOW ON A LEVEL PLAYING FIELD WITH OTHER STATES IN TERMS OF SOLAR POLICY SUPPORT, IS THE SURGING SOLAR DEVELOPMENT EXPERIENCED DURING RECENT YEARS SLOWING?**

A. No, it is not. Figure 3 shows that the number of new interconnection requests submitted in 2016 for utility-scale ground mounted solar generators above 1 MW declined by only 5%, compared to 2015, while the total MWs proposed to be developed increased by approximately 38%. Notably, twice as many requests and three times as many MWs were proposed in DEP as compared to DEC in 2016, continuing a trend seen in past years.

**Figure 3**



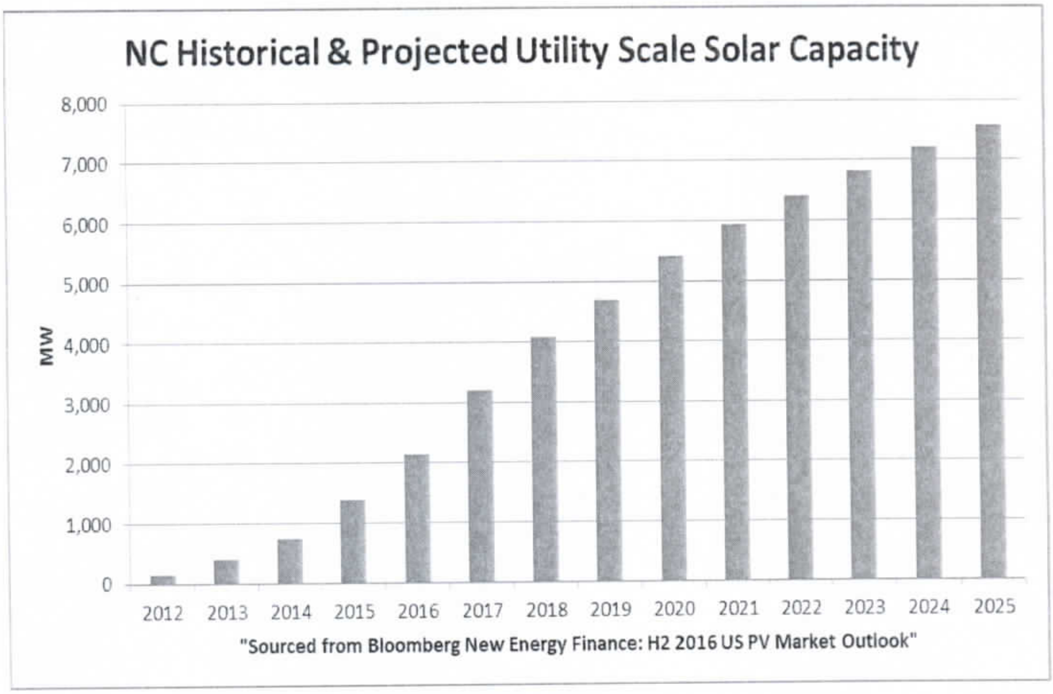

**New Interconnection Requests above 1 MWs to DEP and DEC in NC*

Despite the expiration of the RETC, and despite DEP and DEC having met the NC Solar Set-Aside requirement for at least the next decade, development of 5 MW and less QFs has not slowed. For comparison, in the last 5 years, DEC and DEP combined have interconnected more than 200 solar generators between 4 and 5 MWs, mostly to their distribution systems. In only the past two years, since January 1, 2015, the Commission has approved more than 350 applications for certificates of public convenience and necessity ("CPCN") to construct QF solar generators between 4 and 5 MWs within DEC and DEP, with most being developed in the DEP East service territory.

Looking ahead, Figure 4 presents Bloomberg New Energy Finance's projections that, under current policies, installed utility-scale solar in North

Carolina will exceed 10% of total installed solar capacity nationally in 2018, and will exceed 5,000 MWs of installed solar by 2020.

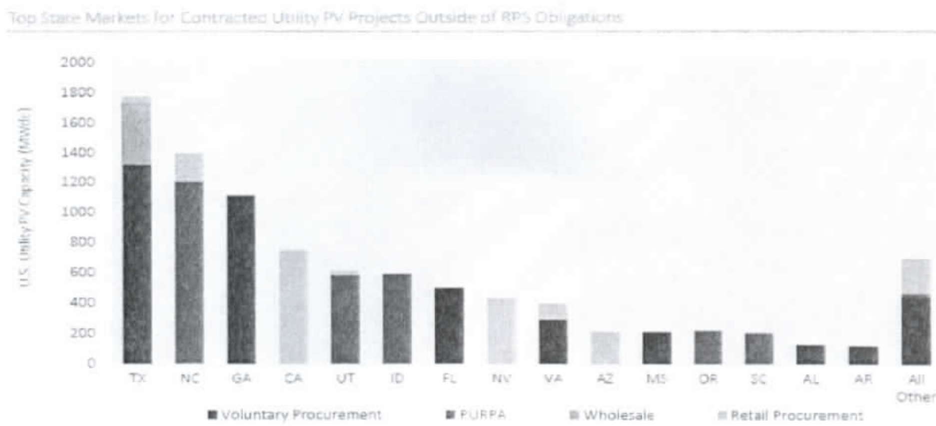
**Figure 4**




**Q. WHY IS NORTH CAROLINA CONTINUING TO EXPERIENCE SURGING SOLAR GROWTH?**

A. The Commission's PURPA policies are now the predominant driver of solar development in North Carolina. As highlighted in the Companies' Joint Initial Statement, an August 2016 report by the U.S. Energy Information Administration ("EIA") found that North Carolina is now leading all 50 states, including California, in PURPA-supported utility-scale solar installed capacity.[20] Another February 2016 report by the research firm Greentech Media ("GTM") similarly shows North Carolina's PURPA-driven solar growth compared to other states, and highlights that 60% of all installed PURPA solar is located in North Carolina.[21]

**Figure 5**




The price level and term of avoided cost rates calculated under the Commission's historic PURPA polices, the low threshold to establish a LEO commitment to sell QF power, as well as the current longer fixed terms for PURPA standard contracts for generators up to 5 MW has made North Carolina the fastest growing solar development marketplace in the Southeast and a leader in distributed utility-scale solar deployment nationally.

[20] U.S. Energy Information Administration, North Carolina has more PURPA-qualifying solar facilities than any other state, (August 23, 2016), accessible at http://www.eia.gov/todayinenergy/detail.php?id=27632.

[21] GTM Research, The Next Wave of U.S. Utility Solar, Procurement Beyond the RPS (February 2016) at 16, 28, accessible at https://www.greentechmedia.com/research/report/the-next-wave-of-us-utility-solar.

**Q. PLEASE DESCRIBE THE LONG-TERM FINANCIAL IMPACTS OF THIS SURGING SOLAR GROWTH ON CUSTOMERS.**

A. Surging QF development means that a growing percentage of our customers' cost of electricity will be attributable to must-purchase power from QFs. In theory, customers should be indifferent to such circumstances because of PURPA's avoided cost limit. In practice, however, customers may be economically disadvantaged if avoided cost rates do not accurately reflect the utilities' true cost of alternative power supply. When utilities compensate QFs at rates that exceed their avoided costs, it has a two-fold effect that harms customers. First, customers must bear the incremental costs from QFs that are higher than contemplated by both the letter and intent of PURPA. Second, these unjustifiable higher rates compound that effect by increasing QF growth as developers seek to take advantage of the avoided cost rates being offered above the utility's avoided costs (and above competing offers to sell power in other states). This is especially the case where long-term avoided cost rates result in locked-in PURPA contracts spanning 5-, 10-, or 15-year terms with no ability to modify the rates paid based upon future changes in commodity prices or other factors that drive the utility's cost of energy.

As described by Witness Snider, the projected financial impact of the existing, interconnected PURPA solar for DEC's and DEP's customers is approximately $2.9 billion over the next 12 to 14 years. Further, witness Snider has calculated the potential for approximately $1.0 billion in long-term overpayment to QFs by the Companies' customers when compared to the Companies' current calculation of its avoided cost rates proposed in this proceeding. As discussed by Witness Snider, this significant overpayment risk to our customers is a key driver supporting the Companies' proposed modifications to its avoided cost rates in this proceeding.

**Q. DOES THE CONTINUING PROJECTED GROWTH IN PURPA SOLAR AT LEAST HELP TO MEET THE COMPANIES' FUTURE REPS OBLIGATIONS?**

A. Not materially, for two reasons. First, as noted above, DEP has largely achieved long-term REPS compliance through 2028, while DEC's recent October 2016 RFP for solar/general resources will procure sufficient renewable resources to allow the Company to meet its solar-specific and total REPS obligation requirements through at least 2019.

Second, PURPA solar energy delivered to the Companies is no different than non-renewable "brown power," unless the solar generator also transfers the RECs and other environmental attributes to the Companies as part of the energy sales transaction. Under PURPA and current policies in North Carolina, a non-renewable PURPA PPA agreement to sell power represents only the sale of energy and does not transfer RECs to the Companies.

**Q. WHY ARE OTHER STATES NOT EXPERIENCNG THE SAME PURPA GROWTH THAT IS OCCURING TODAY IN NORTH CAROLINA?**

A. There are likely a number of reasons, some of which relate to how PURPA is being implemented in other jurisdictions across the country.

First, a significant portion of utilities across the country are now exempt from PURPA's must purchase requirements from larger QFs as a result of modifications to PURPA enacted by the Energy Policy Act of 2005 ("EPACT 2005"). More specifically, EPACT 2005 enacted Section 210(m) of PURPA, which provided for termination of a utility's obligation to purchase energy and capacity from QFs greater than 20 MW if, upon application to FERC, it is determined that QFs have non-discriminatory access to competitive wholesale energy and capacity markets and/or the utility is located in a regional transmission organization ("RTO") that manages a non-discriminatory transmission and interconnection process pursuant to an open access transmission tariff. Under this authority, utilities in RTOs, such as the Companies' affiliated utilities in Indiana, Ohio, and Kentucky, have generally been granted exemption from the PURPA must purchase requirements for QFs larger than 20 MW.[22] Notably, while the Section 210(m) exemption has largely been limited to terminating utility purchase obligations from larger QFs above 20 MW, the terms of PURPA standard tariff offerings to smaller

[22] *Duke Energy Shared Services, Inc.*, 119 FERC ¶61,146 (2007).

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QFs in these deregulated jurisdictions have often been limited to "market-based" offers as well. Thus, the result has been that QF development – both large and small – has seen a more modest growth in these jurisdictions.

Second, other states have adopted PURPA implementation policies that are not as favorable to QFs as North Carolina's policies. For example, most states in the Southeast do not require that utilities offer a maximum 15-year long-term fixed rate contract as part of a standard offer. Additionally, more recently, other state Commissions outside of RTOs and wholesale markets have taken steps to adjust their PURPA standard offer implementation, largely in response to significant growth of intermittent wind and solar QF generation that increasingly was causing PURPA over-supply and growing operational challenges. For example, in 2012, the Idaho Public Utilities Commission granted a joint request by its three regulated utilities to reduce the standard offer eligibility cap for wind and solar projects to the 100 kW floor.[23] In 2015, the Idaho Commission also evolved its standard offer by limiting the term of its standard PPA to a period of two years.[24] In March 2016, the Oregon Public Utility Commission reduced that State's eligibility cap for avoided cost pricing from 10 MW to 3 MW for the largest of its three

[23] *In re the Commission's Review of PURPA QF Contract Provisions Including the Surrogate Avoided Resource (SAR) and Integrated Resource Planning (IRP) Methodologies for Calculating Avoided Cost Rates*, Order No. 32697, Idaho Public Utilities Commission Case No. GNR-E-11-03 (Dec. 18, 2012), *reh'g denied*, Order No. 32737 (Feb. 5, 2013).

[24] *In re Id. Power Co.'s Petition to Modify Terms and Conditions of PURPA Purchase Agreements*, Order No. 33357, Idaho Public Utilities Commission Case Nos. IPC-E-15-01, AVU-E-15-01, and PAC-E-15-03 (Aug. 20, 2015), *reh'g denied*, Order No. 33419 (Nov. 5, 2015).

regulated investor-owned utilities, as part of more comprehensive efforts to manage QF growth.[25] In July 2016, the Montana Public Utilities Commission issued an Order approving an emergency motion for suspension of NorthWestern Energy's long-term avoided cost rates for QFs over 100 kW that had previously been set in 2013.[26]

**Q. ARE THE COMPANIES ADVOCATING THAT THE COMMISSION ADOPT PURPA POLICIES BASED ON APPROACHES FOLLOWED IN OTHER JURISDICTIONS?**

A. Not necessarily. The Companies' proposals in this case seek to strike a just and reasonable balance for North Carolina between continuing the standard offer for small QFs of 1 MW or less while better protecting customers from the growing PURPA overpayment risk associated with offering longer term contracts to larger QFs. The foregoing discussion is intended to highlight that as other States more finely tune their PURPA implementation and rebalance the justness and reasonableness of long-term avoided cost obligations on customers against the encouragement of QFs, the result for North Carolina may be an even greater interest in selling power to the Companies at the Commission-approved standard offer avoided cost rates. As the Commission has implicitly recognized in the past, when QFs entitled to long-term Standard

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[25] *In re PacifiCorp, dba Pacific Power, Application to Reduce the Qualifying Facility Contract Term and Lower the Qualifying Facility Standard Contract Eligibility Cap*, Order No. 16-130, Oregon Public Utility Commission Case No. UM-1734 (Mar. 29, 2016).

[26] *In re NorthWestern Energy's Motion for Emergency Suspension of Tariff Schedule QF-1*, Order No. 7500, Montana Public Service Commission Docket No. D2016.5.39 (July 25, 2016).

Offer rates are no longer "of limited number and size," the overpayment risk increases significantly for customers should the utility's actual avoided costs deviate from the approved standard offer rates. As I highlight above, this overpayment risk has grown to an unprecedented level – approximating $1.0 billion based upon PPAs for currently installed solar QFs, as calculated by Witness Snider, and will only increase in the future as PURPA-driven solar growth continues.

**Q. PLEASE EXPLAIN HOW THE STATE'S ENERGY POLICIES SHOULD BE RECOGNIZED IN BALANCING THE EVOLVING REGULATORY CIRCUMSTANCES YOU DISCUSS ABOVE.**

A. The Public Utilities Act is an integrated plan through which North Carolina has recognized its public policy interests in assuring an "adequate and reliable supply of electric power . . . to the people, economy, and government of North Carolina." G.S. § 62-2(a). To that end, the General Assembly through G.S. § 62-2(a)(3a) and (6), has declared that the Commission shall, amongst other actions, ". . . require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable . . ." as well as "foster the continued service of public utilities on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety and for the promotion of the general welfare . . . ."

As described by Witness Holeman, the recent rapid growth of utility-scale PURPA solar is increasingly challenging the Companies' ability to plan for and cost-effectively deliver electricity to our customers. This is especially the case as the number of long-term PURPA PPAs exceeding avoided costs continues to grow, as explained by Witness Snider. Recognizing these evolving economic and regulatory circumstances, the Companies submit that the broader purpose of the Public Utilities Act – to assure the delivery of reliable and least cost electricity to citizens and businesses of the State – should be considered in the Commission's assessment of the public interest under PURPA.

Additionally, the State enacted REPS to diversify the resources used to reliably meet the energy needs of consumers in the State. While REPS should continue to promote integration of a cost-effective mix of renewables and demand side resources to reliably serve customers, the State's renewable energy resource mix is now increasingly being driven by variable and intermittent PURPA solar. As shown in Figure 6 below, 1,600 MWs of the 1,684 MWs of renewable generation either on-line, under construction, or in development in DEC is QF solar, while that number exceeds 4,900 MWs out of 5,200 MWs in DEP.

## Figure 6

| DE Carolinas: | | |
|---|---|---|
| On-Line and Under Contract | MW | SubTotal |
| Biogas | 10.4 | |
| Biomass | 1.6 | |
| Hydroelectric | 16.8 | |
| Landfill Gas | 40.2 | |
| Solar | 505.6 | |
| | 574.6 | 574.6 |
| Under Contract, but not On-line | MW | SubTotal |
| Solar | 67.8 | |
| | 67.8 | 642.4 |
| Pending, Not Under Contract, Not On-Line | MW | SubTotal |
| Biogas | 1.1 | |
| Biomass | 7.1 | |
| Hydroelectric | 4.0 | |
| Landfill Gas | 3.0 | |
| Solar | 1,027.1 | |
| | 1,042.3 | 1,684.7 |

| DE Progress | | |
|---|---|---|
| On-Line and Under Contract | MW | SubTotal |
| Biomass | 236.0 | |
| Hydroelectric | 8.4 | |
| Landfill Gas | 34.8 | |
| Solar | 1,112.0 | |
| | 1,391.2 | 1,391.2 |
| Under Contract, but not On-line | MW | SubTotal |
| Solar | 494.4 | |
| | 494.4 | 1,885.6 |
| Pending, Not Under Contract, Not On-Line | MW | SubTotal |
| Biogas | | |
| Biomass | 5.8 | |
| Hydroelectric | | |
| Landfill Gas | | |
| Solar | 3,323.6 | |
| | 3,329.4 | 5,215.0 |

As the levels of QF solar continue to increase beyond the total renewable energy compliance obligations contemplated by the State's REPS policy, the Companies also submit that the broader purpose of enacting REPS – to integrate a diverse and cost-effective mix of renewables and demand side resources to reliably serve customers – should also be considered in the Commission's assessment of the public interest under PURPA.

## IV. RECOMMENDED MODIFICATIONS TO AVOIDED COST CALCULATION METHODOLOGY

**Q. ARE THE COMPANIES RECOMMENDING CHANGES IN HOW THEY CALCULATE THEIR AVOIDED COST RATES?**

A. Yes. As explained more by Witnesses Yates, Snider, Freeman, and Holeman, the current economic and regulatory circumstances, as well as the growing system operational challenges now confronting the Companies and their customers, require the Companies to request the Commission's reappraisal of several of its previously-approved PURPA policies. The proposed modifications are a first necessary step in a longer process towards optimizing DEC's and DEP's solar procurement to provide for continued long-term utility-scale solar development in North Carolina, while ensuring the Companies continue to deliver cost-effective and reliable power to our customers on a well-planned and coordinated basis.

**Q. PLEASE EXPLAIN HOW THE COMPANIES' PROPOSED MODIFICATIONS WILL APPLY PROSPECTIVELY.**

A. As explained by Witness Snider, approximately 1,100 MWs of proposed solar QFs in development and progressing through the Companies' respective interconnection queues are eligible for the standard offer avoided cost rates approved in the Commission's previous Sub 140 proceeding as well as the prior 2012 standard offer rates established in Docket No. E-100, Sub 136 ("Sub 136"). These QFs have not interconnected to the Companies and are not delivering power, so the Companies are not yet purchasing from them.

These QFs, however, have already "locked in" to avoided cost rates to be paid over the next 15 years that the Commission has approved in these past avoided cost dockets. Therefore, when I refer to the Companies' proposed modifications applying to future QF purchases, I want to be clear that I am referring to those QFs that will be selling to the Companies in the future, subject to the rates to be approved in this docket.

## A. PROPOSED STANDARD OFFER ELIGIBILITY LIMIT MODIFICATION

**Q. DO THE COMPANIES PROPOSE THAT THE COMMISSION LOWER THE CAPACITY ELIGIBILITY LIMIT FOR STANDARD AVOIDED COST RATES FROM 5 MW TO 1 MW?**

A. Yes. For the reasons discussed below, lowering the capacity threshold from 5 MW to 1 MW is appropriate and justified at this time, given current economic and regulatory conditions in North Carolina.

**Q. WHAT IS THE PURPOSE OF A CAPACITY ELIGIBILITY LIMIT FOR STANDARD CONTRACTS?**

A. In its Order No. 69, FERC recognized that while standard "one-size-fits-all" avoided cost rates cannot account for the differences between QFs of various sizes and types, smaller QFs could be challenged by the transactional costs of bilaterally negotiating individualized rates. Thus, FERC balanced those concerns by requiring States implementing PURPA to make standard rates and terms available to QFs with a design capacity of 100 kW and smaller.

The FERC also included in its regulations that States "may" put into effect standard rates for purchases for QFs with a design capacity above 100 kW, explaining "that the establishment of standard rates for purchases can significantly encourage cogeneration and small power production, provided that these standard rates *accurately reflect the costs* that the utility can avoid as a result of such purchases."[27] State-level implementation of the standard eligibility limit varies considerably from jurisdiction-to-jurisdiction. Utilities in at least 20 states have standard rates for QFs under 100 kW, while utilities in at least 33 states have eligibility caps at or under 5 MW. Notably, the Companies are not recommending that the Commission adopt the FERC minimum 100 kW as an eligibility threshold in this docket.

**Q. HOW HAS THIS COMMISSION IMPLEMENTED A CAPACITY ELIGIBILITY LIMIT FOR STANDARD CONTRACTS IN NORTH CAROLINA?**

A. As noted above, prior to 1985, standard avoided cost tariffs were available to all QFs up to 80 MW in Duke and CP&L, while DNCP's standard offer was capped at 100 kW due to the significant ongoing development of cogeneration and small power production facilities in DNCP's service territory in the early 1980s. In 1985, the Commission established a 5 MW eligibility limit for the Companies' as well as DNCP's standard tariffs. The small power production industry was in a nascent state at that time. Consequently, to help encourage

[27] *Order No. 69* at 53 (emphasis in the original).

the development of QFs, the Commission established eligibility criteria that ensured that smaller project developers, who may not have the resources or expertise to negotiate with a utility, still had access to the standard terms and conditions. Small, inexperienced QF developers could then avail themselves of a standard offer, without having to expend time and resources negotiating with large, experienced utilities.

**Q. HOW HAS THE 5 MW ELIGIBILITY LIMIT IMPACTED THE NORTH CAROLINA SOLAR MARKETPLACE?**

A. As highlighted in the Companies' Joint Initial Statement, North Carolina has become a national leader in distributed utility-scale solar development – 5 MWs at a time. In the last 5 years alone, distribution-level utility-scale solar generation development has exploded in North Carolina, particularly when compared with the rest of the United States. Figure 7 shows the significant level of development in North Carolina relative to the rest of the United States.

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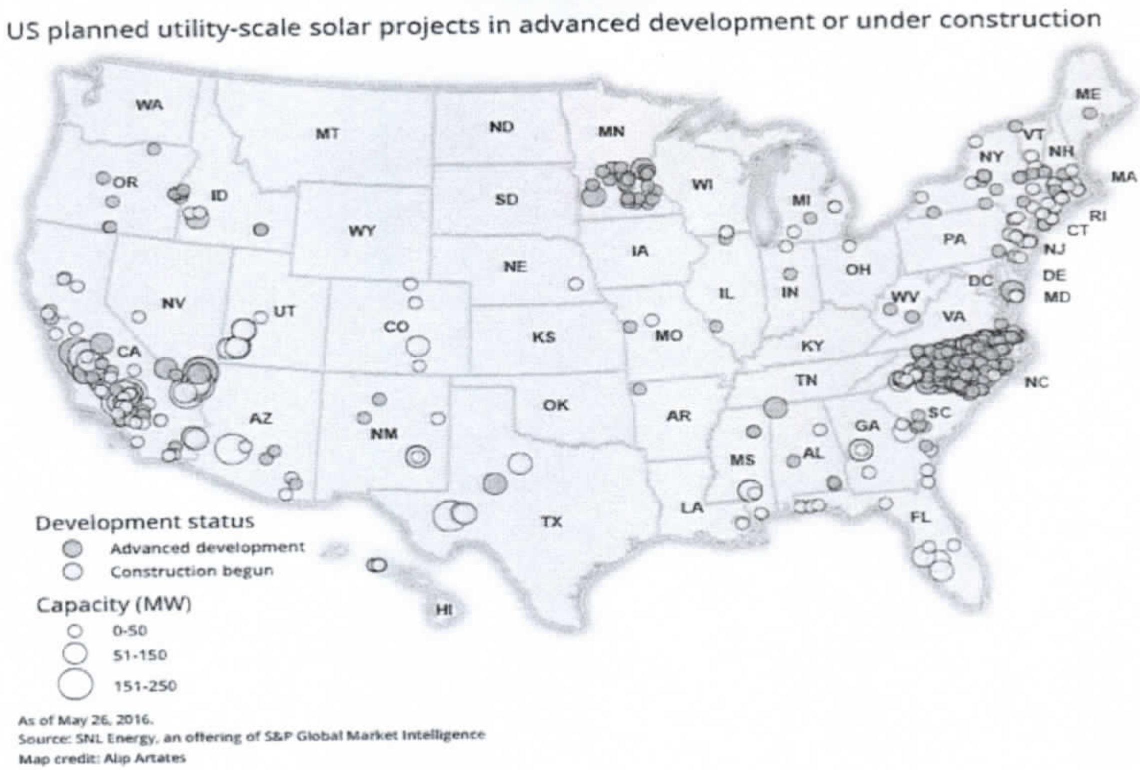
**Figure 7**




Focusing on the DEP service territory alone, DEP has been inundated with development of 5 MW and less solar generators. In 2011, DEP had only one installed solar generation facility with a nameplate capacity of 1 MW or more. The next year, DEP had 19 installed solar generators above 1 MW, totaling approximately 61 MWs. Five years later, that number has increased more than ten-fold, with more than 220 such projects, totaling approximately 1,100 MWs of installed solar as of December 31, 2016.

The recent significant development of hundreds of QF solar generators right at the current 5 MW standard offer ceiling is compelling evidence that

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the Commission's PURPA standard offer policies – not prudent utility planning or efficient solar development – is driving much of North Carolina's utility-scale solar growth. As solar developers "disaggregate" potentially larger and more cost efficient solar projects to meet the 5 MW standard contract threshold, numerous challenges have arisen, including the ongoing challenge of managing the interconnection of these generators to rural circuits on the Companies' increasingly saturated distribution systems. Notably, the "disaggregation" of QF projects qualifying for the Idaho standard offer led the Idaho Public Utilities Commission to suspend and ultimately permanently reduce the standard contract eligibility from 10 MW to 100 kW for wind and solar generators in 2011.[28] Moreover, even as DEC and DEP are seeing increases in the number of solar developers seeking to interconnect larger QFs with their systems, vigorous development of the 5 MW or less solar QFs continues.

**Q. HOW HAS THE 5 MW ELIGIBILITY THRESHOLD IMPACTED THE COMPANIES' CUSTOMERS?**

A. The surge of 1 MW to 5 MW QFs in North Carolina has exposed customers to hundreds of standard contract solar projects that have obtained LEOs, resulting in significant long-term financial commitments on behalf of DEC's and DEP's customers that are well in excess of the Companies' current system

[28] *In the Matter of Joint Petition of Idaho Power Company, Avista Corporation, and Pacificorp, DBA Rocky Mountain Power to Address Avoided Costs Issues and to Adjust the Published Avoided Cost Rate Eligibility Cap*, Idaho PUC Order No. 322262 (June 8, 2011).

incremental costs. As described by Witness Snider and highlighted above, the prices contained in existing PPAs (both standard offer and negotiated PPAs) with the Companies include prices that are more than 30% higher than the Companies' current avoided costs, creating an approximate $1.0 billion in above-market payments over the lifetime of those PPAs. Since March 2015, when the Companies' previous proposed avoided cost rates were filed, approximately 300 projects between 4 and 5 MWs have obtained CPCNs, thereby potentially establishing LEOs under the rates based on inputs to avoided cost calculations made two years ago. Because these 1 MW to 5 MW QFs are entitled to the standard offer, they are able to "lock in" to these standard, long-term fixed rates for likely the next 15 years on the day they establish their LEOs. This results in the same avoided cost rates being applicable to QFs even if they are put into service years apart. During that lengthy interval, factors affecting the purchasing utility's avoided costs, such as fuel costs, environmental regulations, and capacity needs, can change dramatically, affecting the utility's actual avoided costs.

**Q. WHY IS LOWERING THE ELIGIBILITY THRESHOLD CRITICALLY IMPORTANT AT THIS TIME?**

A. As recognized in Order No. 69, establishing standard avoided cost rates above 100 kW "significantly encourages" QF development, but also increases the risk that a standard offer rate could become stale or otherwise deviate from the

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utility's actual avoided cost.[29] Based on the level of utility-scale solar development in North Carolina, continued significant encouragement of solar development through the 5 MW threshold (and 15-year long-term fixed rate contracts) is increasingly causing unjust and unreasonable long-term PURPA purchase obligations on the Companies' customers. Lowering the eligibility limit for standard rates to 1 MW is in the public interest in light of the current PURPA solar marketplace in North Carolina and will allow rates offered to QFs above 1 MW to be more just and reasonable as they will be based on a more precise assessment of the costs that particular QFs allow the purchasing utilities to avoid.

The 5 MW threshold has served its purpose of encouraging the development of QFs, particularly solar QFs, in North Carolina. In a very short time, however, the 5 MW threshold evolved from a reasonable policy for encouraging development of relatively small QFs to a highly attractive solar development business model for sophisticated and well-capitalized entities from around the country. The majority of developers of solar projects 5 MW and less are no longer unsophisticated "mom and pop" developers, unable to manage negotiating a PPA with the utilities. To the contrary, in recent years, well-experienced, sophisticated, and well-capitalized solar developers have taken advantage of the guaranteed, long-term fixed rates of the standard contract by obtaining LEOs on multiple 5 MW and less solar facilities. Based

[29] *Order No. 69* at 23.

on the foregoing, the Commission's prior justification for the 5 MW threshold simply no longer exists.

**Q. WHY ARE THE COMPANIES RECOMMENDING 1 MW AS THE APPROPRIATE THRESHOLD VERSUS 100 KW, AS ALLOWED BY PURPA?**

A. Based upon current economic and regulatory circumstances, the Companies recommend 1 MW as a reasonable proxy to differentiate between small QFs seeking to install renewable or alternative energy facilities for primarily environmental or other non-commercial purposes (e.g., residential customers, retail stores, hospitals, or schools), as compared to larger sophisticated commercial enterprises (such as Apple or Walmart) or power generation developers in the business of owning or operating power generation facilities. Notably, the Companies' net energy metering tariffs are similarly available to customer-generators with a capacity of up to 1 MW in size. Further, since 2010, FERC has not required QFs below 1 MW to self-certify as a QF.[30] Finally, as discussed by Witness Freeman, the Companies' recent experience processing QF solar interconnection requests suggests that 1 MW solar projects are more likely to pass the Section 3 Fast Track process under the North Carolina Interconnection Procedures, which would mean both the PPA and Interconnection Agreement could be obtained in a more standardized and streamlined fashion.

[30] *Order No. 732*, 130 FERC ¶ 61,214 at pp. 33-41 (2010).

**Q. HOW DOES THE PROPOSED 1 MW ELIGIBLITY THRESHOLD ASSIST IN INTEGRATING SOLAR POWER INTO THE COMPANIES' SYSTEMS IN A MORE WELL-PLANNED, COORDINATED MANNER?**

A. In contrast to maintaining the current 5 MW eligibility threshold, lowering the eligibility limit for standard rates to 1 MW will allow the avoided cost rates offered to more QFs to be based on a more precise and timely assessment of the costs that a particular QF allows the utilities to avoid. An eligibility threshold based on more current circumstances will further help ensure that the Companies may begin to transition to a more "well-planned and coordinated" process of integrating solar into their systems, while protecting customers from the potential harm of paying rates above avoided costs. In its *Order on Clarification* in Docket No. E-100, Sub 140, the Commission required the utilities to use the most up-to-date data in determining inputs for negotiated avoided cost rates. Use of the more current avoided cost calculations helps ensure that customers are not forced to pay rates under a standard offer that are stale and, based upon recent experience, can greatly exceed the purchasing utility's actual avoided costs. Further, applying the most up-to-date data will ensure more QFs receive rates based on the most accurate assessment of the utility's avoided cost. Through aligning the avoided cost rates paid to the QF with the utility's avoided costs at the time of the purchase, the Companies' proposed eligibility threshold proposal meets

PURPA's objective of ensuring customers remain indifferent between purchasing utility generation and purchases from QFs at the utility's avoided costs and also protects both customers and QFs in periods of rising and declining energy costs. In addition, the Commission has previously provided guidance on what factors should be considered in bilateral negotiations between the utilities and QFs.[31] Accordingly, bilateral negotiations result in avoided cost rates that more accurately reflect the value that the QF provides to our customers, consistent with the goals of PURPA.

**Q. WILL QFS WITH A NAMEPLATE CAPACITY OF MORE THAN 1 MW STILL BE ENTITLED TO SELL POWER TO THE UTILITIES AT AVOIDED COST RATES?**

A. Yes. The Companies will still be required to purchase the output of these larger QFs, consistent with the requirements of PURPA. These larger QFs, however, would receive avoided cost rates through bilateral negotiations with the purchasing utility and not through the biennially-approved standard offer avoided cost tariff.

[31] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 12-13, Docket No. E-100, Sub 66 (July 16, 1993).

**Q. IN THE PREVIOUS AVOIDED COST DOCKET, THE COMMISSION DECLINED TO REVISE THE 5 MW ELIGIBILITY THRESHOLD, NOTING ALLEGATIONS BY QF DEVELOPERS THAT THE COMPANIES' QF PPA NEGOTIATION PROCESS WAS PROTRACTED. HAVE THE COMPANIES AND QFS GAINED MORE EXPERIENCE WITH THE PPA NEGOTIATION PROCESS?**

A. Yes. Since the commencement of the Sub 140 proceedings in 2014, the Companies have gained greater experience in negotiating PPAs with QFs larger than 5 MW, as QF developers are increasingly planning and developing projects both inside and outside the Sub 140 standard tariff parameters. The Companies have successfully negotiated more than 22 PURPA-only PPAs with large QFs since 2014, with 10 of those PPAs negotiated since January 1, 2016. Of those 10, 3 are with the same developer. Moreover, many of these negotiations have been with the same owner/developers of 5 MW and less QFs that avail themselves of the standard contract. Producing monthly avoided cost calculations for these negotiated PPAs has also become routine. Moreover, the negotiation process has also become more standardized and begins with a standardized set of Duke-proposed terms and conditions that are consistent from contract to contract. The use of these standardized terms and conditions means that negotiations do not have to begin anew with the larger QFs that have become accustomed to them, thereby reducing the costs and the time formerly associated with bilateral negotiations. In sum, the Companies have gained even more experience in negotiating PPAs since 2014 and are prepared to efficiently negotiate PPAs in good faith with QFs larger than 1 MW.

### B. PROPOSED ADJUSTMENTS TO LONG-TERM LEVELIZED RATES OPTIONS

**Q. WHAT DO THE COMPANIES PROPOSE AS THE MAXIMUM CONTRACT TERMS FOR STANDARD CONTRACTS?**

A. As explained in the Joint Initial Statement, the Companies propose eliminating the long-standing 5-year and 15-year standard contract term options and instead propose a single 10-year long-term avoided cost contract with fixed capacity rates. As further discussed by Witness Snider, energy rates included in the contract will be updated every 2 years as part of the Commission's biennial review of the Companies' avoided cost. In addition, the capacity component of the Companies' avoided cost rates recognizes the capacity value of the QF starting in the first year that the Companies' IRPs demonstrate an actual capacity need. The Companies moderate their near-term lack of capacity need by levelizing the capacity component over the 10-year term of the proposed standard contract. Witness Snider will explain in more detail how this proposal better reflects the utility's avoided costs, but I will explain how the proposal is consistent with PURPA's goals.

**Q. HOW DOES THE COMPANIES' PROPOSAL BALANCE THE NEED TO ENCOURAGE QF DEVELOPMENT WITH THE RISK OF OVERPAYMENTS BY THE COMPANIES' CUSTOMERS?**

A. The Companies have accounted for the current economic and regulatory circumstances in designing their proposed avoided cost standard offer. Significantly, the energy component will be reset in future biennial avoided cost proceedings, mitigating the significant forecast risk of over- or under-projecting long-term commodity prices. This will protect customers from over-paying for avoided energy in future years where fuel commodity forecasts are not as certain. At the same time, it will provide QFs a continuing stream of revenue and the potential upside benefit of increased rates if energy prices increase above forecasted levels during the 10-year contract term. In short, the biennial adjustment of the energy component will more closely align future avoided energy cost payments with the Companies' actual avoided cost of energy, whether that energy cost is increasing or decreasing. The avoided capacity component now recognizes the capacity value in years where the Companies' IRPs show an actual capacity need, while the proposed standard offer rate design addresses the impact of DEC's and DEP's near-term lack of capacity need by levelizing the capacity component over the 10-year term of the proposed standard offer.

**Q. IN PREVIOUS BIENNIAL AVOIDED COST PROCEEDINGS, THE COMMISSION HAS DECLINED TO ELIMINATE THE 15-YEAR LONG-TERM FIXED CONTRACT. WHY SHOULD IT DO SO IN THIS PROCEEDING?**

A. The Commission has consistently stated it must "continually reconsider" the requirement for 10-year and 15-year contract terms "as economic circumstances change from one biennial proceeding to the next."[32] In past proceedings, the Commission has concluded that the 15-year maximum contract struck a balance between encouraging QF development and reducing the utilities' exposure to overpayments because "the facilities entitled to long-term rates are generally of limited number and size." The significant proliferation of 5 MW solar QFs in the DEP and DEC service territories, however, has resulted in the number of QFs entitled to these long-term contracts no longer being of limited number and size. As the number of solar QFs requesting to sell power under standard avoided cost rates increases, the financial burden and "overpayment risk" increases for the Companies' customers. As highlighted earlier, Witness Snider provides more detail on the actually-experienced PURPA financial obligation to our customers and the significant overpayment risk for our customers in the future, which is no longer compatible with PURPA's mandate that avoided cost rates and policies

[32] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 10, Docket No. E-100, Sub 100 (Sept. 29, 2005)

be just and reasonable to utility customers and in the public interest. The Companies' proposal seeks to restore the balance between encouraging QF development and protecting customers from the risk of overpayments by aligning the avoided energy cost paid to QFs with the Companies' actual system incremental avoided costs, while at the same time providing the QF with a fixed, long-term revenue stream of capacity payments.

**Q. IS IT THE COMPANIES' EXPERIENCE THAT THE INCREASED IMPRECISION IN PROJECTING AVOIDED COST RATES FOR LONGER TERM CONTRACTS IS MITIGATED BY OVERPAYMENTS AND UNDERPAYMENTS TENDING TO BALANCE OUT OVER TIME?**

A. No, it is not. One assumption underlying FERC's statement in Order No. 69 is that "in the long run, 'overestimations' and 'underestimations' of avoided costs will balance out" in that QF development would remain essentially constant regardless of avoided cost rates and regulatory circumstances. The enormous recent surge in QFs developments in North Carolina disproves this assumption. Long-term avoided cost rates in excess of the utilities' actual avoided cost rates, long-term fixed rate contracts, and the low threshold to obtain a LEO have resulted in large numbers of solar QFs locking in avoided cost rates in North Carolina for the next 15 years. As discussed, these rates are well in excess of the Companies' actual current avoided costs. As the amount of solar QF energy and capacity having secured LEOs has grown exponentially over the past few years, the 15-year maximum contract term has resulted in significant overpayment commitments by customers, now approximating $1.0 billion, which far exceed the potential for counterbalancing underpayments for the foreseeable future.

**Q. IS THE COMPANIES' PROPOSAL TO ADJUST AVOIDED ENERGY RATES EVERY TWO YEARS CONSISTENT WITH PURPA?**

A. Yes. Through 16 U.S.C. § 824a-3(b), PURPA requires avoided cost rates that are just and reasonable to customers, in the public interest, and not discriminatory to QFs. This means that avoided cost rates should not exceed incremental costs of alternative energy that the utility would generate or purchase from another source. If contracts extend for many years, the forecasted avoided cost rates become increasingly inaccurate, no longer mirroring the utility's incremental costs. Thus, long-term contracts with forecasted rates shift the risks of those rates not aligning with avoided costs to the utilities' customers. This shifting of the growing risk to customers becomes increasingly unjust, unreasonable, and contrary to the public interest as greater and greater QF capacity avails itself of these longer-term rates. Moreover, FERC's regulations implementing PURPA do not prescribe a minimum or maximum term for a "long-term" contract. Different states have differing terms. For example, South Carolina requires a maximum 10-year fixed long-term contract.[33] In contrast, Georgia requires a maximum 5-year fixed long-term contract.[34] Other states such as Tennessee, Alabama, and Mississippi have all approved minimum standard offer terms of one year.[35] As noted above, the Idaho Public Utilities Commission recently approved a two-year term contract for wind and solar QFs larger than 100 kW. The Companies standard offer rate design attempts to reasonably encourage continued QF development under the current economic and regulatory circumstances, by balancing QFs' interest in longer term contracts with customers' interest in better controlling costs and managing the significant commodity price forecast risk associated with longer-term PPAs.

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[33] *Proceeding for Approval of the Public Utility Regulatory Policies Act of 1978 (PURPA) Avoided Cost Rates for Electric Companies,* Order No. 2016-349, Public Service Commission of South Carolina, Docket No. 1995-1192-E at 1 (May 12, 2016).

[34] Georgia Power, Electric Service Tariff, Solar Purchase Schedule SP-2 at 11.20.

[35] *See* Tennessee Valley Authority, Dispersed Power Production guidelines, Attachment A, Dispersed Power Price Schedule CSPP, Contract Requirement; Alabama Power, Rate PAE - Purchase of Alternate Energy at 4 (37th Rev.); Entergy Mississippi, Inc., Standard Schedule for Purchases from Qualifying Cogeneration and Small Power Production Facilities with Design Capacity of 100 kilowatts or Less, Schedule QF-17 at 2 (rev'd Dec. 30, 2016).

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**Q. WITH RESPECT TO THE COMPANIES' AVOIDED CAPACITY COSTS, HOW DO THEY RECOMMEND THE METHODOLOGY FOR CALCULATING THOSE COSTS BE IMPROVED TO RESTORE BALANCE TO PURPA IMPLEMENTATION IN NORTH CAROLINA?**

A. Based on the specific concerns outlined above, as further discussed in the testimony of Witness Snider, the Companies recommend the capacity credits in the standard tariffs account for their respective relative need for generating capacity. Simply put, the Companies' customers should not be obligated to pay for capacity value in years where there is no need for additional capacity.

**Q. WHY ARE THE COMPANIES PROPOSING TO ADJUST THE AVOIDED CAPACITY COST CALCULATION METHODOLOGY TO ACCOUNT FOR THE RELATIVE NEED FOR GENERATING CAPACITY?**

A. As discussed by Witness Snider, one principal aspect of PURPA was, and remains, that QFs should be fairly and reasonably compensated for the incremental capacity and energy costs that, *but for* capacity and energy provided by the QF, the utility would be forced to generate or purchase elsewhere to serve its customers. If the purchase of power from a QF does not, in part or in total, avoid the utility's need to incur incremental capacity and energy expense, then the QF should not be compensated for providing that benefit. PURPA was not intended to force a utility to pay for capacity

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that it does not otherwise need; *i.e.*, if the QF is not allowing the utility to avoid capacity that the utility would otherwise generate or purchase from another source, then there is no incremental capacity cost being avoided. Both Order No. 69 and subsequent FERC decisions have reinforced this point, specifically the FERC's decision in City of Ketchikan.[36] In that decision, the FERC stated that while the utility is legally obligated to purchase energy or capacity provided by a QF, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. North Carolina law also contemplates this concept in that "a determination of the avoided energy costs to the utility shall include . . . the expected costs of the additional or existing generating capacity ***which could be displaced***."[37] Witness Snider's approach to calculating avoided capacity merely seeks to effectuate this concept in practice by providing avoided capacity credits to QFs based upon the actual capacity being avoided by the purchase of power from the QF.

**Q. IN THE PREVIOUS AVOIDED COST PROCEEDING, THE COMMISSION DECLINED TO ACCEPT A SIMILAR PROPOSAL, WHY SHOULD IT DO SO IN THIS PROCEEDING?**

A. Witness Snider testifies about how the increasing levels of solar energy and capacity that the Companies must purchase under PURPA will not lead to

[36] *City of Ketchikan, Alaska*, 94 FERC ¶ 61,293 (2001).

[37] N.C. Gen. Stat. § 62-156(b)(2)(emphasis added).

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delaying or deferring future generating capacity needs required to reliably serve customer's loads. With respect to the Commission's previous decision in Docket No. E-100, Sub 140, I note that the Commission cited FERC's decision in Hydrodynamics[38] as supportive of its determination that the utilities should not include zeros in the early years when calculating avoided capacity rates. The Hydrodynamics decision, however, did not pertain to a utility's proposal to recognize a capacity value only in years where the Companies' IRPs showed a need. Instead, Hydrodynamics concerned a limit on installed capacity purchases by NorthWestern Energy from wind QFs. Upon review, FERC found that the 50 MW cap on QF-provided capacity prevented certain wind QFs from receiving any fixed, long-term compensation for capacity. Citing its decision in Ketchikan, FERC stated in Hydrodynamics that avoided cost rates need not include the cost for capacity when the utility's demand or need for capacity is zero. The FERC concluded, however, based upon the record before it, that the cap on installed capacity did not have "a clear relationship" to the utility's "actual demand" for capacity; therefore, the Ketchikan rationale did not apply.

In contrast, in this docket, the Companies have not proposed to cap capacity purchases from certain solar QFs at an arbitrary level. The Companies have instead proposed avoided cost rates that moderate the impact of DEC's and DEP's near-term lack of capacity need by levelizing the

[38] *Hydrodynamics*, 146 FERC ¶ 61,193 (2014).

capacity component over the 10-year term of the proposed standard offer. The Companies will continue to purchase capacity, but they request to do so at rates that have a clear and direct relationship to the Companies' actual capacity needs as reflected in their IRPs. As such, the Companies' proposal is consistent with FERC's decisions in both Ketchikan and Hydrodynamics.

### C. MODIFICATION TO PAF TO REFLECT RELIABILITY OF A CT

**Q. ARE THE COMPANIES PROPOSING TO MODIFY THE PAF?**

A. Yes. Consistent with the Companies' other proposals to better align the avoided cost rates that our customers will pay to QFs in the future with the value they provide, the Companies proposed to modify the currently approved PAF of 1.2 to 1.05 for QFs eligible for the standard offer. Witness Snider provides the rationale supporting this modification in his testimony.

**Q. DOES THIS PROPOSED MODIFICATION IN THE PAF ALSO APPLY TO SMALL HYDROELECTRIC QFS ELIGIBLE FOR SCHEDULE PP-H?**

A. No, it does not. The Companies entered into a Stipulation of Settlement ("Hydro Stipulation") with the North Carolina Hydroelectric Group ("NC Hydro"), which the Commission approved in the Sub 140 avoided cost proceedings. Consistent with the direction in G.S. § 62-156 to "encourage . . . [and] enhance the economic feasibility" of hydro QFs, the Hydro Stipulation, which expires December 31, 2020, provides that the Companies shall maintain certain pre-existing avoided cost policies, including a 2.0 PAF, when calculating the avoided capacity costs for run-of-river hydroelectric QFs that are 5 MW and less. In addition, and consistent with G.S. § 62-156 and other Commission orders, the Hydro Stipulation provides that the Companies shall continue to offer the option of 5-, 10-, and 15-year terms for contracts with the same hour options as provided under previously approved DEC and DEP rate schedules.

### D. PROPOSED MODIFICATIONS TO TERMS AND CONDITIONS

**Q. PLEASE DESCRIBE THE MODIFICATIONS THAT YOU HAVE MADE TO THE COMPANIES' STANDARD OFFER TERMS AND CONDITIONS.**

A. The Companies have amended their Schedule PPs, their PPAs and their Terms and Conditions to reflect the above proposals. In addition, the Companies have amended Paragraph 14 of their Terms and Conditions to provide the circumstances that are considered "an emergency condition." These circumstances expressly include any circumstance that requires action by the Companies to comply with NERC/SERC Reliability Corporation regulations or standards, the significance of which is further discussed by Witness Holeman.

The Companies have also amended Paragraph 1(e) of their Terms and Conditions to clarify that PPAs shall not be transferred and assigned by a

Seller QF to any person, firm, or corporation that is party to any other PPA under which it sells or seeks to sell power to the Companies as a QF, if that party is located within one-half mile of the original Seller QF. This clarification relates to the availability of the Companies' Schedule PPs. Schedule PP is not available to a QF owned by a customer or affiliate or partner of a customer who sells power to the Companies from another QF of the same energy resource located within one-half mile, as measured from the electrical generating equipment, unless the combined capacity is equal to or less than 1 MW. These amendments are intended to prevent evasion of this geographic restriction through subsequent consolidation of ownership to QFs after their PPAs under the standard offer have been executed.

## E. <u>LEGALLY ENFORCEABLE OBLIGATION</u>

**Q. PLEASE DESCRIBE THE CONCEPT OF A LEGALLY ENFORCEABLE OBLIGATION OR "LEO" UNDER PURPA.**

A. FERC's regulations implementing PURPA provide QFs the option to sell power to the utility on either an "as available" basis or pursuant to a "legally enforceable obligation." Under FERC's regulations, the LEO evinces a commitment by the QF to "deliver energy and capacity to a utility over a specified term" and thereby obligates the utility to purchase its power in the absence of a mutually-binding contract. FERC has explained that a QF's right to sell its output pursuant to a LEO was intended "to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility *merely by refusing to enter into a contract with the qualifying facility*."[39] Thus, the LEO concept created by PURPA protects the QF's right to sell power to the utility, as the QF and the utility can either negotiate and agree to a PPA or, where the utility refuses to enter into a contract, the QF can bind the utility to purchase power from the QF by establishing a non-contractual, but still binding, LEO.

**Q. WHO DETERMINES WHETHER A LEO HAS BEEN ESTABLISHED?**

A. The Commission and other state regulatory authorities (or a non-regulated utility) tasked with setting avoided cost rates under PURPA are responsible for determining whether and when a LEO is created, and the procedures for obtaining approval of such an obligation by the QF.[40] In the absence of – or upon the utility's refusal to negotiate – a PPA, the date upon which the QF makes a legally enforceable commitment to sell power to the utility is the date that the utility and its customers should become obligated under PURPA to purchase power from the QF.

**Q. WHY ARE DEC AND DEP RECOMMENDING THE COMMISSION REVIEW NORTH CAROLINA'S LEO POLICIES AT THIS TIME?**

A. The Companies recommend that the Commission reevaluate this aspect of North Carolina's PURPA implementation because the current "Sub 140 LEO standard" is increasingly imposing unjust and unreasonable purchase

[39] *Order No. 69* at 57-58 (emphasis added).

[40] *Order No. 688-A*, 119 FERC ¶ 61,305 at p. 139 (2007).

obligations on the Companies' customers without actually obligating the QF to sell to the utility. Because the LEO has recently been used in North Carolina to establish the date upon which the QF becomes eligible for the utility's avoided costs, allowing the LEO date to deviate significantly from the power delivery date is harmful to customers resulting in payments in excess of avoided costs. This issue also becomes significantly more important in light of the Companies' proposal to cap the biennially-established standard avoided cost tariff eligibility at 1 MW, thereby allowing the Companies to use more current and accurate avoided costs in the non-standard contract context for all larger and sophisticated QFs.

As discussed in the Companies' Joint Initial Statement, the Commission in the Sub 140 proceeding approved a clear and transparent process by which a QF may establish a LEO. Since December 2015, a QF can establish a LEO by (1) self-certifying with FERC as a QF; (2) obtaining a CPCN from the Commission to construct the generator; and (3) indicating its intent to make a commitment to sell the facility's output to a utility pursuant to PURPA via the use of an approved Notice of Commitment Form ("NoC Form"). While the Companies recognize that this standard, and specifically the NoC Form, provides the QF and the utility with clear guidance regarding the date upon which a LEO is alleged to have arisen, this new standard also has had the perverse consequence of making the QF's "commitment to sell" increasingly meaningless.

**Q. PLEASE EXPLAIN.**

A. North Carolina law has long required generator owners, including QFs, to obtain a CPCN prior to construction. The Commission has recognized that this CPCN requirement is imposed under North Carolina law, not PURPA. Importantly, while obtaining a CPCN may provide some basic indicia of a QF's intention to sell its output to the utility under PURPA, it does not in any way create an obligation on the QF to do so or provide the utility any assurance that a certificated QF will provide capacity and energy to the utility starting on a specified date or over a specified term. For example, Rule R8-64(d)(2) allows a QF to wait up to five years to begin construction without obtaining a CPCN renewal. Further, renewable QFs under 2 MW are exempt from the CPCN requirements under G.S. § 62-110.1(g), and now must only give notice of their planned construction under Commission Rule R8-65. Therefore, while obtaining a CPCN or filing a Report of Proposed Construction may provide some indication that a QF intends to sell power, it does not create any actual commitment to do so by the QF, as originally contemplated by FERC's PURPA regulations.

The QF's act of obtaining self-certification as a QF by filing a Form 556 also does not provide any additional indicia of commitment by the QF to sell to the utility. Currently, this leaves submission of the NoC Form as sole foundation upon which a QF theoretically makes a legally enforceable commitment to the utility to sell its power – thereby theoretically allowing the utility to avoid other plans to construct needed new generation or purchase alternative power over a specified term. Witness Freeman will explain more how this process can be improved to better align the QFs' commitment to sell with the Companies' actual avoided cost rates, thereby meeting PURPA's objective of only paying QFs the utility's actual avoided costs and protecting customers from the risk of overpayments.

## V. TRANSITION TO SMARTER, MORE SUSTAINABLE SOLAR INTEGRATION

**Q. YOU HAVE SUGGESTED SEVERAL REFORMS TO THE COMMISSION'S PURPA IMPLEMENTATION POLICIES. ARE THESE REQUESTED REFORMS SUFFICIENT TO TRANSITION NORTH CAROLINA TO SMARTER AND MORE SUSTAINABLE SOLAR INTEGRATION?**

A. No, not on their own. They do, however, represent a critically necessary first step in the transition away from the current uncontrolled PURPA standard offer-driven solar development business model and towards optimizing DEC's and DEP's solar procurement in a better managed and sustained way for the benefit of our customers. As noted in Section VI of the Companies' Joint Initial Statement, the Companies recognize that additional proceedings may be required to transition North Carolina towards a smarter renewable energy future. This includes continued refinement of the non-standard PURPA implementation process for generators above 1 MW, as well as a new

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solicitation process designed with the goal of transitioning solar development and utility-scale solar integration away from the uncontrolled PURPA process towards a more well-planned and coordinated competitive solicitation approach. The Companies specifically support a stakeholder-developed competitive solicitation procurement model for utility-scale renewable resources that would better align deployment with the Companies' IRP and potential future REPS compliance needs, as well as overcome the operational limitations imposed by PURPA on managing QF resources. As addressed in the Joint Initial Statement, the Companies support a procurement process that achieves the benefits of solar resources for DEC's and DEP's customers (1) at least cost through a managed bidding and procurement process; and (2) assures that solar resources can be operated as "effectively dispatchable" generators, similar to the Company's own solar generator resources.

**Q. HOW DOES PURPA IMPOSE OPERATIONAL LIMITATIONS ON THE COMPANIES' MANAGEMENT OF QF RESOURCES?**

A. As explained more by Witness Holeman, PURPA limits the ability of the utility to curtail its purchase of energy or capacity from a QF. Under the FERC's regulations, absent contractual agreement otherwise, a QF selling power pursuant to a long-term contract may be curtailed and purchases discontinued only in a "system emergency." Solar QFs project their energy onto the grid whenever the sun shines. Thus, without operational dispatch and contractual curtailment rights, system operators cannot readily manage the unconstrained solar power that they must take under PURPA. In contrast, the Companies' own solar facilities are subject to curtailment by the Companies' system operators, enabling them to cost-effectively integrate solar power from those facilities into operations without challenging reliable operations.

**Q. HOW WOULD A COMPETITIVE SOLICITATION SUPPORT SOLAR GROWTH IN A SMART, SUSTAINABLE WAY?**

A. The Companies believe that a competitive solicitation will lower costs for customers, provide improved operational controls, and open a new market for solar facilities outside of PURPA. As envisioned by the Companies, curtailment and dispatch capability will be incorporated into the PPAs, allowing system operators to better plan for, manage, and operate their systems. In addition, the Companies envision a process that allows DEC and DEP to plan where the new solar generation is located, while offering longer term contracts and procurement of an established amount of solar MW as an incentive to add additional new solar installations in a thoughtful and managed process overseen by an independent third party. For these reasons, the Companies have requested the Commission initiate a separate proceeding, with interested stakeholders, to collaborate on the development of a competitive solicitation process for North Carolina.

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

A. Yes, it does.

BY MS. FENTRESS:

Q Ms. Bowman, did you also cause to be prefiled in this docket on April 10th of this year 52 pages of rebuttal testimony?

A (MS. BOWMAN) Yes.

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

A No.

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.

MS. FENTRESS: Mr. Chairman, at this time I would move that the rebuttal testimony of Ms. Bowman be copied into the record as if given orally from the stand.

CHAIRMAN FINLEY: Ms. Bowman's rebuttal testimony of April 10, 2017, consisting of 52 pages is copied into the record as though given orally from the stand.

MS. FENTRESS: Thank you.

(WHEREUPON, the prefiled rebuttal testimony of **KENDAL C. BOWMAN** is copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

| | | |
|---|---|---|
| In the Matter of<br>Biennial Determination of Avoided Cost<br>Rates for Electric Utility Purchases from<br>Qualifying Facilities – 2016 | )<br>)<br>)<br>)<br>) | REBUTTAL TESTIMONY OF<br>KENDAL C. BOWMAN ON BEHALF<br>OF DUKE ENERGY CAROLINAS,<br>LLC AND DUKE ENERGY<br>PROGRESS, LLC |

## I. INTRODUCTION AND PURPOSE

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

A. My name is Kendal Crowder Bowman. My address is 410 South Wilmington Street, Raleigh, NC 27601.

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

A. I am employed as Vice President Regulatory Affairs and Policy North Carolina for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (collectively the "Companies"), which are wholly owned subsidiaries of Duke Energy Corporation.

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

A. Yes. I submitted direct testimony in this proceeding on behalf of the Companies on February 21, 2017.

**Q. ARE YOU INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?**

A. No, I am not.

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

A. The purpose of my rebuttal testimony is to address the arguments made by other parties pertaining to the Companies' recommendations to evolve North Carolina's implementation of the Public Utility Regulatory Policies Act ("PURPA") to reflect the current economic and regulatory circumstances in the State. Specifically, I rebut the arguments made by North Carolina

Sustainable Energy Association ("NCSEA") Witness Ben Johnson and Witness Carson Harkrader that the Commission should not revise its current PURPA policies as applied to the standard terms and conditions at issue in this docket. I also rebut the testimony of Southern Alliance for Clean Energy ("SACE") Witness Thomas Vitolo and NCSEA Witnesses Johnson and Harkrader pertaining to the eligibility cap for standard avoided cost contracts by explaining that the Companies' proposed 1 megawatt ("MW") eligibility cap is consistent with PURPA and in the best interest of our customers. Along with Witness Gary R. Freeman, I respond to the Public Staff's request for additional information on the Companies' current and proposed process for negotiating power purchase agreements ("PPAs") with qualifying facilities ("QFs").

I also address other parties' arguments that the Companies' proposed 10-year standard offer PPA rate design, including the biennial updating of the avoided energy rate, should not be adopted in this proceeding. Specifically, I explain why adjusting the Companies' avoided energy rates every two years as part of a longer, fixed-term purchase agreement appropriately balances the need to encourage QF development with the risk of overpayments by our customers. However, I also propose a compromise "alternative option" that would allow small QFs eligible for the Companies' standard offer to fix the two-year energy rate for the full 10-year term as an interim solution while the Companies continue to evaluate the alternative options proposed by Public

Staff Witness John R. Hinton to mitigate long-term forecast risk of overpayment by customers between now and the next biennial proceeding.

I also provide legal justification for recognizing the avoided capacity value only in the years in which the Companies' integrated resource plans ("IRPs") show an actual capacity need, as well as the Companies' proposed modification to its terms and conditions to allow for non-discriminatory curtailment of QF energy during system emergencies. Finally, I address the Public Staff's recommendation for the Commission to direct the Companies to develop a separate avoided energy rate for solar QFs as not appropriate in the current proceeding, but a reasonable directive for consideration in the next biennial avoided cost proceeding if all avoided costs and potential benefits of incremental solar QF generation on the Companies' systems are taken into account.

## II. THE RECORD IN THIS PROCEEDING DEMONSTRATES THAT NORTH CAROLINA IS AT A CROSSROADS WITH RESPECT TO CONTINUATION OF THE COMMISSION'S LONG-HELD PURPA POLICIES

**Q. PLEASE REINTRODUCE THE COMPANIES' POSITIONS WITH RESPECT TO EVOLVING THE STATE'S IMPLEMENTATION OF PURPA TO BETTER MEET THE PUBLIC INTEREST.**

A. The Commission's implementation of PURPA over the past decade has been designed to encourage development of QF generators, including utility-scale solar generators with a nameplate capacity of 5 MW or less, by requiring the Companies and Dominion North Carolina Power ("DNCP" and together with the Companies, the "Utilities") to offer standard 5-, 10-, and 15-year, long-term levelized fixed rate PPAs. In my prefiled direct testimony, however, I described the unprecedented surge in utility-scale solar QF generators, including hundreds of solar projects sized between 4 MW and 5 MW that have interconnected and are now selling energy to the Companies pursuant to Commission-approved long-term PURPA avoided cost rates. My prefiled direct testimony and the direct testimony of Companies' Witnesses Lloyd M. Yates, Glen A. Snider, John Samuel Holeman III, and Witness Freeman, detailed the Companies' experiences and challenges resulting from this explosive solar QF growth in North Carolina. We explained how this surge of solar development has resulted in, and will continue to result in, long-term financial impacts to our customers as solar QFs 5 MWs and less have "locked into" long-term fixed energy and capacity rates that are higher than the Companies' current avoided cost rates. Moreover, we discussed the Companies' growing experiences operating the DEC and DEP balancing authorities ("BA") in parallel with a rapidly-evolving PURPA-driven, increasingly solar-only, renewables environment and how the influx of intermittent solar QFs is challenging the Companies' ability to plan and operate their generation fleets, manage their transmission systems, and assure reliable power is delivered to our customers.

The Commission has recently stated that "the nature of these recurring, biennial proceedings has always required consideration of current economic conditions facing public utilities and QFs and whether changed conditions justify changes in avoided cost rates and/or PURPA implementation."[1] Today's economic and regulatory circumstances, which the Companies described in their Joint Initial Statement and prefiled direct testimony, justify a comprehensive review of the Commission's implementation of PURPA. The Companies' recommended modifications to the standard offer are a needed first step in a longer transition to a more "well-planned and coordinated" process that balances PURPA's goal of encouraging QF development with the dual challenges of integrating solar into our system and aligning the costs our customers are ultimately paying for solar QF power with the value they are receiving.

**Q. DO THE PARTIES FILING TESTIMONY IN THIS PROCEEDING GENERALLY AGREE THAT THE UTILITIES HAVE EXPERIENCED RAPID AND EXPLOSIVE GROWTH IN SOLAR QF DEVELOPMENT?**

A. Based upon my review of the testimony and comments filed in this proceeding, no party disputes that North Carolina has experienced a surge in solar QF development growth over the past few years. In addition to the Companies' experiences described in their testimony, DNCP Witness Scott Gaskill reported in his prefiled direct testimony that, since February 2014, distributed solar in DNCP's North Carolina service territory has also increased significantly.[2] The Public Staff, after its review and investigation into the

1 *Order Denying Motion* at 3-4, Docket No. E-100, Sub 148 (Jan. 18, 2017).

2 DNCP Gaskill Testimony, at 6-9.

Utilities' Initial Statements and direct testimony, similarly noted the recent "tremendous" and "unparalleled" growth in installed utility-scale solar capacity in DEC's and DEP's service territories.[3] NCSEA Witness Johnson also agreed that North Carolina has experienced "significant" growth in solar power production and highlighted that solar growth in North Carolina is occurring at a "substantial and more rapid" pace than in neighboring states.[4]

**Q. DID THE PUBLIC STAFF CONCLUDE THAT THE RAPID GROWTH IN PURPA SOLAR GENERATION HAS IMPACTED AND WILL CONTINUE TO IMPACT OUR CUSTOMERS AND OPERATIONS?**

A. Yes. As recognized by Public Staff Witnesses Hinton and Dustin R. Metz, the tremendous growth in "must take" energy from PURPA solar QFs in North Carolina has both: (i) increased the risk of potential overpayments by our customers; and (ii) posed challenges to meeting the Companies' obligation to provide safe, reliable, and economic service to customers, including complying with mandatory NERC BAL Standards.[5] As a result, the Public Staff agreed with several of the Companies' recommendations to evolve the Commission's long-held PURPA policies in light of the current economic and regulatory conditions.

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3 Public Staff Hinton Testimony, at 5, 7.

4 NCSEA Johnson Testimony, at 33, 34,

5 Public Staff Hinton Testimony, at 7; Public Staff Metz Testimony, at 6.

**Q. DO ANY OTHER INTERVENORS SUPPORT EVOLVING THE COMMISSION'S LONG-STANDING PURPA POLICIES TO MEET THE RISKS AND CHALLENGES POSED BY THE RECENT SURGE IN QF SOLAR FACILITIES IN NORTH CAROLINA?**

A. Notably, the North Carolina Electric Membership Corporation ("NCEMC"), a wholesale customer of the Companies that does not typically intervene in the Commission's biennial avoided cost proceedings, filed Comments in this proceeding. NCEMC is a generation and transmission cooperative responsible for the full or partial power supply requirements of 25 distribution cooperatives throughout North Carolina. According to its Comments, NCEMC serves more than 850,000 farms, homes, and businesses, and it purchases significant amounts of power from the Utilities. Because of these purchase arrangements with the Utilities, and the potential for "pass-through" to NCEMC of certain energy and capacity costs to comply with PURPA or to integrate QFs, NCEMC is concerned about the "undeniable" cost increases resulting from the influx of solar in North Carolina.[6] NCEMC also reported that it depends on the Utilities' bulk power services, especially their transmission services, to serve its customers in North Carolina. Thus, NCEMC also expressed concern that over-generation events in the DEP BA would potentially present significant reliability challenges, resulting in congestion at a transmission level that would threaten system reliability and

6 NCEMC Comments, at 7.

NCEMC's ability to reliably serve its customers' energy needs.[7] For these reasons, NCEMC urged the Commission to evolve its existing PURPA policies to avoid potentially allowing these increased costs and system impacts to continue.

**Q. DO NCSEA AND SACE SUPPORT THE COMPANIES' PROPOSALS TO EVOLVE THE COMMISSION'S PURPA POLICIES TO ADDRESS THE CURRENT ECONOMIC AND REGULATORY CIRCUMSTANCES RESULTING FROM THE SURGE OF QF SOLAR FACILITIES?**

A. No. While NCSEA Witness Johnson recognizes the recent, unprecedented solar QF development in North Carolina and acknowledges that North Carolina's PURPA experience is an outlier when compared to most other states, his testimony on behalf of NCSEA opposes nearly every aspect of the Companies' proposals to evolve the Commission's PURPA standard offer policies. SACE Witness Vitolo does not even mention the State's recent surge of solar QF development in his testimony. Instead, his testimony tends to urge the Commission to simply maintain the status quo by re-stating its previous avoided cost conclusions from the 2014 avoided cost proceeding.

7 NCEMC Comments, at 8.

**Q. DO YOU AGREE WITH WITNESS JOHNSON'S ASSERTION THAT THE COMPANIES' PROPOSALS TO EVOLVE THE COMMISSION'S PURPA POLICIES ARE INTENDED TO "SLAM ON THE BRAKES" WITH RESPECT TO SOLAR DEVELOPMENT IN THIS STATE?**

A. I do not agree at all. The Companies' proposed modifications to the standard offer in this proceeding are not intended to stop solar development in North Carolina, but instead are intended to be a necessary first step to continuing solar development in this State in a smarter, more sustainable way. Other longer-term steps may include the Companies' proposal to collaborate with interested parties to develop a competitive solicitation process to provide for sustainable growth in new solar resources, continuing to participate in the Interconnection Stakeholder discussions, and addressing additional PURPA policies for larger QFs in the near future.

The current PURPA policies, however, have resulted in uncoordinated and unrestrained growth of PURPA solar facilities in North Carolina in an unmanageable way. I discuss our specific proposed modifications in more detail later in my testimony, but I note here that the proposed modifications are specifically intended to address the two current and critical issues with respect to the continued surge in solar QFs that are 5 MWs and less: (i) the increased risk of overpayments for PURPA solar power by our customers; and (ii) the increasing challenges to reliably planning and operating the Companies' systems as additional QF solar is installed. As discussed in the

Companies' Joint Initial Statement, DEC and DEP have long-range PPAs with Commission-set avoided costs ranging from $55 to $85 per MWh, while the Companies' current avoided costs are closer to $35 per MWh. This disparity has resulted in our customers bearing an estimated $1 billion overpayment for PURPA power for the remaining lives of the applicable PPAs, which is the next 12-15 years. With respect to our systems' operations, PURPA requires the Companies to interconnect and purchase from QFs. The purchase is "must take," and the Companies currently have no ability to dispatch and only limited emergency rights to curtail QF generators under the PURPA construct. As Witness Holeman explains, this inhibits the Companies' ability to maximize the reliable and economic operation of the energy grid. In sum, as described in my direct testimony, the Commission has previously evolved its PURPA policies over the last 35 years in response to changing economic and regulatory circumstances. The Companies respectfully request that the Commission again exercise the broad discretion afforded to States under PURPA to assure the Companies' avoided cost rates are just and reasonable to our customers and the State's PURPA policies serve the public interest in light of the current economic and regulatory circumstances existing in North Carolina today.

**Q. DOESN'T THE COMMISSION HAVE AN OBLIGATION TO ENCOURAGE QF DEVELOPMENT THROUGH PURPA AS ADVOCATED BY NCSEA WITNESS JOHNSON?**

A. I agree that PURPA is intended to encourage QF development, but not at any and all costs. QF advocates often stress that the purpose of PURPA is to encourage development of QFs, as Witness Johnson has done in this proceeding, while downplaying PURPA's specific directive that the tariffs under which QFs sell power must also be "just and reasonable to the electric consumers of [the purchasing utility] and in the public interest."[8] Furthermore, PURPA is not intended as a means to make any and all QFs viable. Instead, as this Commission has previously recognized, PURPA specifically requires the Commission *to balance* the goal of encouraging QF development and the interests of the State's electric customers when it implements PURPA.[9] Moreover, PURPA is not intended to be an unlimited source of subsidy for QFs. Contrary to Witness Johnson's assertion, the Commission is not expected to treat avoided costs as a pricing "*floor*" for QF purchases.[10] Congress has made clear that rates paid to QFs under PURPA must be capped at the utility's respective avoided cost, and be just and reasonable to the utility's customers.[11] Thus, avoided costs provisions should

8 16 USC § 824a-3(b)(1).

9 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 11, Docket No. E-100, Sub 136 (Feb. 21, 2014).

10 NCSEA Johnson Testimony, at 21.

11 16 USC § 824a-3(b), (d).

operate as *a ceiling*, not an open-ended entitlement for QFs. As the U.S. Supreme Court has found, public service commissions implementing PURPA may even authorize payments to QFs that are below full avoided cost if the lower rate is still sufficient to encourage QF development.[12] The Companies are not suggesting that the Commission adopt rates below full avoided costs, however, this permitted result underscores Congress' intent and the legal limitations of PURPA. PURPA supports QF developers by ensuring they can interconnect and sell all of their output to utilities, but only if they can do so efficiently, i.e., at no incremental cost to the utility's customers.

**Q. DO YOU AGREE WITH WITNESS JOHNSON'S OPINION THAT THE IDENTIFIED OPERATIONAL RISKS AND CHALLENGES DO NOT NECESSITATE THE COMPANIES' PROPOSED MODIFICATIONS IN THE COMMISSION'S PURPA POLICIES FOR THE STANDARD OFFER?**

A. No, I do not. Although Witness Johnson appears to at least acknowledge the operational issues caused by the influx of intermittent and unconstrained solar energy confronting our system operators, he effectively dismisses these challenges as mere "growing pains" in integrating more solar energy in North Carolina, and he rejects the Companies' proposed solutions.[13] As discussed above and further described by Witnesses Yates and Holeman, it is important

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12 *Am. Paper Inst. v. Am. Electric Power Serv. Corp.*, 461 U.S. 402, 416 (1983) ("[A]ny state regulatory authority . . . may apply to [FERC} for a waiver of the rule. A waiver may be granted if the applicant demonstrates that a full-avoided-cost rate is unnecessary to encourage cogeneration and small power production 18 C.F.R. Sec. 292.403.").

13 NCSEA Johnson Testimony, at 209.

for the Commission to understand how the State's implementation of PURPA will impact the rates customers pay and the way the Companies manage and operate their generating fleets and transmission and distribution systems for decades to come.

**III. <u>REDUCING THE ELIGIBILITY CAP FOR STANDARD RATES, TERMS, AND CONDITIONS TO 1 MW WILL MAKE AVOIDED COST RATES MORE ACCURATE AND WILL NOT BURDEN THE PARTIES OR THE COMMISSION</u>**

**Q. PLEASE EXPLAIN THE PURPOSE OF THE COMPANIES' PROPOSAL TO LOWER THE SCHEDULE PP STANDARD OFFER TARIFF ELIGIBILITY CAP FROM 5 MW TO 1 MW.**

A. As stated in my direct testimony, the purpose of this proposal is to ensure that the avoided cost rates offered to larger "utility-scale" QFs above 1 MW are based on a more precise and timely assessment of the costs that a particular QF allows the Companies to avoid. By lowering the eligibility threshold to 1 MW, the Commission will balance two competing objectives under PURPA. First, it enables the Companies to negotiate more precise avoided cost rates with more solar QFs, based on the most up-to-date data and taking the specific characteristics of the particular QF into consideration to mitigate the risk of customer over-payment for QF power. At the same time, however, this proposal also ensures that the standard tariff rates are available to smaller "non-utility scale" QFs that may not be able to justify the cost and effort of negotiating avoided cost rates with the Utilities. Notably, a standard offer capped at 1 MW still "significantly encourages" small QF development over

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and above the standard offer requirements set forth in the Federal Energy Regulatory Commission's ("FERC") regulations.[14]

The record in this proceeding shows that the 5 MW threshold has served its intended purpose and has significantly encouraged QF development in North Carolina. As I generally described in my direct testimony, and as confirmed in the direct testimony of Public Staff Witness Hinton, more than 750 QF generators at or just below 5 MWs have obtained certificates of public convenience and necessity ("CPCN") in North Carolina since 2013, the vast majority of which are solar QFs desiring to sell power to the Utilities under PURPA.[15] Based on this unprecedented level of utility-scale solar, continued significant encouragement of solar development through this 5 MW threshold will cause unjust and unreasonable long-term PURPA purchase obligations on the Companies' customers. Transitioning to 1 MW at this time is necessary and reflects the current economic and regulatory circumstances.

**Q. IS DECREASING THE MAXIMUM CAPACITY ELIGIBLE FOR STANDARD TARIFF RATES CONSISTENT WITH PURPA?**

A. Yes. Neither NCSEA Witness Johnson nor SACE Witness Vitolo contend that the Companies' proposal violates PURPA or FERC's regulations implementing PURPA, which only require that standard contracts be offered

14 18 C.F.R. 292.304(c)(2); *Order No. 69, FERC Stats. & Regs., Preambles 1977-1981* P30,128 at 30,865. ("Order No. 69") (In approving subsection (c)(2) providing the option for standard offer purchase rates above 100 kW, FERC explained that "establishment of standard rates for purchases can significantly encourage cogeneration and small power production, provided that these standard rates accurately reflect the costs that the utility can avoid as a result of such purchases.").

15 Public Staff Hinton Testimony, at 41 (aggregating approved CPCNs for 4 to 5 MW QFs from 2013 to 2016 equates to 753 new generators being certificated during this period.)

to QFs of 100 kW or less.[16] Moreover, as discussed in my direct testimony, the Commission has modified the eligibility threshold in the past, based on the economic and regulatory circumstances present at the time.[17] When the Commission first implemented the 5 MW eligibility threshold in 1985, the small power production industry was in its infancy in North Carolina. As discussed above, this significant encouragement is no longer required or appropriate.

**Q. DID THE OTHER PARTIES FILING TESTIMONY IN THIS DOCKET AGREE WITH THE COMPANIES' PROPOSAL TO REDUCE THE ELIGIBILITY THRESHOLD?**

A. The Public Staff agreed with both the Companies' and DNCP's proposals to adjust the eligibility threshold to 1 MW, based on the current economic and regulatory circumstances. NCSEA Witness Harkrader opposed the adjustment. NCSEA Witness Johnson, however, recommended only a slight adjustment to the threshold, and SACE Witness Vitolo recommended that the Commission simply maintain the status quo.

**Q. WHAT WAS NCSEA WITNESS JOHNSON'S RECOMMENDATION?**

A. Witness Johnson recommended adjusting the threshold from 5 MWs downward "perhaps to 3.75 or 4 MW" on the grounds that the Commission should be cautious and see how the market reacts before adjusting the

16 18 C.F.R. 292.304(c).

17 DEC-DEP Bowman Direct Testimony, at 10-13, 34.

threshold further or, alternatively, simply postponing this decision for another two years.[18]

**Q. WHY IS A 1 MW ELIGIBILITY THRESHOLD MORE APPROPRIATE THAN A 3.75 MW OR 4 MW ELIGIBILITY THRESHOLD, AS WITNESS JOHNSON RECOMMENDS?**

A. In the Companies' experience, a 1 MW eligibility threshold is a reasonable proxy to differentiate between utility-scale developer-sponsored solar and smaller QFs seeking to install renewable or alternative energy facilities for primarily environmental or other non-commercial reasons. Furthermore, as discussed by Witness Freeman, the Companies' experience has been that solar projects at or below 1 MW are more likely to pass the Section 3 Fast Track process, which means that both the PPA and interconnection agreement could be obtained in a more standardized and streamlined fashion. Therefore, the Companies do not find Witness Johnson's limited support for this proposal credible and anticipate that this proposal would be more likely to perpetuate the unconstrained development of large numbers of QFs by well-capitalized, sophisticated solar developers under the Companies' standard offer tariff and PPAs, which is no longer in the public interest and would impose unjust and unreasonable costs on our customers.

18 NCSEA Johnson Testimony, at 219.

**Q. PLEASE RESPOND IN GENERAL TO WITNESS VITOLO'S RECOMMENDATIONS TO MAINTAIN THE STATUS QUO WITH RESPECT TO THE ELIGIBILITY THRESHOLD.**

A. Witness Vitolo makes his recommendations without reference to, or acknowledgement of, the current economic and regulatory circumstances resulting from the tremendous surge of solar QFs in North Carolina. These current economic and regulatory conditions, however, drive the Companies' proposals to modify the standard offer. As Public Staff Witness Hinton provides in his direct testimony, at this time, a 1 MW threshold better reflects current conditions and better protects the ratepayers from the risk of overpayment.[19]

**Q. PLEASE RESPOND TO WITNESS VITOLO'S ASSERTION THAT ADJUSTING THE ELIGIBILITY THRESHOLD TO 1 MW WILL CAUSE SOLAR QFs TO FOREGO ECONOMIES OF SCALE AND BUILD SMALLER PROJECTS TO AVOID THE RISKS AND COSTS OF NEGOTIATION.**

A. Witness Vitolo urges the Commission to retain the 5 MW threshold because it will allow QF developers to retain the economies of scale associated with developing a larger (5 MW) QF project and avoid the risk and cost of negotiations.[20] This will result in "lower costs overall," according to Witness Vitolo. I note, however, that the lower costs of QF development highlighted

19 Public Staff Hinton Testimony, at 44.

20 SACE Vitolo Testimony, at 9.

by Witness Vitolo refer to lower costs for QF developers and not our customers. Our customers do not benefit from these cost savings, because the rates paid to QFs (and borne by the Companies' customers) are based on the Companies' avoided costs, and not the cost incurred by the developers to construct the QF facility.

I would also propose that the Commission view Witness Vitolo's argument in the inverse as actually supporting the Companies' proposed reduction in the standard offer to differentiate between relatively small projects up to 1 MW and utility-scale developer-sponsored solar projects, which have, to date, been developed at 5 MWs to avail themselves of the standard offer. As I explained in my direct testimony, "disaggregating" potentially larger and more cost efficient utility-scale solar projects to meet the 5 MW standard contract threshold has caused numerous challenges, including the ongoing challenge of managing the interconnection of these generators to rural circuits on the Companies' increasingly saturated distribution systems as well as paying stale avoided cost rates to numerous larger QFs up to 5 MWs during a period of declining energy costs.[21] Eliminating the incentive to arbitrarily develop 5 MW solar projects may, in fact, improve economies of scale if solar developers transition to developing larger projects.

21 DEC-DEP Bowman Direct Testimony, at 37.

**Q. HOW DO YOU RESPOND TO WITNESS VITOLO'S CONTENTION THAT THERE IS A SIGNIFICANT POWER IMBALANCE IN QFs' NEGOTIATIONS WITH UTILITIES?**

A. As I stated in my direct testimony, utility-scale solar QFs are no longer being developed by small, fledgling project developers or "customer-owned QFs." Witness Vitolo does not acknowledge that the majority of utility-scale solar project developers are no longer unsophisticated, small developers. For example, my Figure 1 below demonstrates that six large power generation developers, which are participants in the energy supply industry across the United States, account for more than 65% of the standard offer projects in the Companies' combined interconnection queues between 1 MW and 5 MWs.

**Figure 1**

| Upstream Project Developer Name | Projects under Development in DEP | Projects under Development in DEC | Total Projects under Development in Duke Interconnection Queues |
|---|---|---|---|
| Cypress Creek Renewables (includes legacy FLS Energy) | 59 | 24 | 83 |
| Strata Solar | 53 | 8 | 61 |
| ESA Renewables | 25 | 15 | 40 |
| Sunlight Partners | 32 | 1 | 33 |
| Headwaters Solar | 17 | 13 | 30 |
| GreenGo Energy (formerly NARENCO) | 22 | 5 | 27 |
| **Total Top 6 Developers** | **208** | **66** | **272** |

**Q. DO YOU AGREE THAT ADJUSTING THE ELIGIBILITY THRESHOLD WILL RESULT IN PROTRACTED AND COSTLY NEGOTIATIONS BETWEEN QFs AND THE UTILITIES?**

A. No, I do not. As I stated in my direct testimony, the Companies have significant experience negotiating PPAs with solar QF developers, as developers are increasingly planning and developing larger QF projects up to 80 MWs in size over the past few years.[22] The Companies have developed more standardized PPA terms and conditions for larger QFs, effectively streamlining the process. The use of standardized terms means that negotiations do not have to start from scratch and ensures that QFs receive consistent treatment. Additionally, producing updated monthly avoided cost calculations for these negotiated PPAs has become routine. As Witness Vitolo states, the Companies require 25 hours, or just three business days, of staff effort to develop an updated avoided cost calculation and to negotiate an uncontested PPA.[23]

**Q. HOW DO YOU RESPOND TO WITNESS VITOLO'S ASSERTION THAT NEGOTIATIONS WITH THE COMPANIES FOR A PPA CAN TAKE MONTHS?**

A. Two parties are involved in every negotiation, and delays are not always caused by the Companies. Witness Vitolo supports his assertion by referring to a data request response that the Companies provided to SACE, asking for

22 DEC-DEP Bowman Direct Testimony, at 43.

23 SACE Vitolo Testimony, at 8.

the Companies to identify the dates of the legally enforceable obligations ("LEOs") and the execution dates for negotiated PPAs for QFs larger than 5 MWs. The request did not reflect, however, that under the Notice of Commitment form approved by the Commission in Docket No. E-100, Sub 140, "large" QFs have up to six months to execute a PPA after the Companies submit it to the QF for signature.[24] My understanding is that large QFs sometimes wait until that six months is close to expiring to execute a PPA with the Companies.

I would also emphasize, as noted by Public Staff Witness Hinton,[25] that the Companies intend to further streamline and standardize the PPA negotiation process to reduce the transaction costs and the time for negotiating PPAs with QFs. In Witness Freeman's direct testimony, the Companies have proposed contracting procedures that will foster transparency and efficiency in negotiating contracts with QFs, providing clear steps that the QF and utility will follow throughout the negotiation process towards execution of a PPA. Witness Freeman is now providing draft contracting procedures for the Commission's review and approval in his rebuttal testimony. The Companies believe that these procedures can be implemented quickly – with appropriate input from Public Staff and other interested parties – after the Commission issues a final order in this proceeding.

24 Notice of Commitment to Sell the Output of a Qualifying Facility to Duke Energy Carolinas, LLC, or Duke Energy Progress, LLC ¶ 6 (c).

25 Public Staff Hinton Testimony, at 46, 47.

**Q. WHAT ADDITIONAL DETAILS CAN YOU PROVIDE TO THE COMMISSION WITH RESPECT TO CALCULATING AVOIDED COST RATES FOR LARGE QFs THAT ARE NOT ELIGIBLE FOR THE STANDARD OFFER RATES?**

A. The Companies intend to continue to follow FERC and Commission guidance in negotiating PPAs with large QFs. FERC's regulations specifically provide that the following factors can be considered in setting avoided cost rates: (i) the ability of the utility to dispatch the QF; (ii) the expected or demonstrated reliability of the QF; (iii) the terms of any contract or other LEO, including the duration of the obligation; (iv) the extent to which scheduled outages of the QF can be usefully coordinated with scheduled outages of the utilities' facilities; (v) the usefulness of the energy and capacity supplied from the QF in emergencies; and (vi) the individual and aggregate value of energy and capacity from QFs on the electric utility's system.[26] In addition, the Commission has directed the Utilities to negotiate with QFs in good faith and has listed specific issues to be addressed in negotiations with large QFs and QFs not otherwise eligible for the standard offer. These issues include:

- The appropriate contract and the parties' best forecast of avoided capacity and energy credits over the duration;

26 18 C.F.R. 292.304(e).

- Capacity credits that reflect the need (or lack of need) for additional capacity at the time of deliveries under the contract are actually to be made;
- The availability of capacity during the utility's daily and seasonal peaks;
- The utility's ability to dispatch the QF;
- The expected or demonstrated reliability of the qualifying facilities;
- The terms and provisions of any applicable contract or other LEO, including the termination notice requirement and sanctions for noncompliance;
- The extent of which the scheduled outages of the QF during system emergencies, including its ability to separate its load from its generation;
- The individual and aggregate value of the capacity from the QFs on the utility's system;
- The smaller capacity increments and shorter lead times that might be available with the additions of capacity from QFs;
- The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from the QF;
- The alternative of long-term rates that are not levelized or only partially levelized;
- The alternative of long-term rates that include levelized capacity payments and variable energy payments;

- Appropriate notice prior to the expiration of the contract term, the renewability of the contract, and the provisions for setting the appropriate rates for each renewed contract; and
- The appropriate security bond or other protection for the utility if levelized or partially levelized payments are negotiated.[27]

In addition to this long-established guidance, the Commission has also more recently addressed the Companies' requirements when negotiating with large QFs in its *Order on Clarification* in Docket No. E-100, Sub 140 ("*Clarification Order*"). In the *Clarification Order*, the Commission directed that in the course of bilateral negotiations, the Companies are expected to use the most up-to-date data to determine inputs for negotiated rates and that any party "is free to identify specific characteristics of a particular QF that merit consideration in the calculation of negotiated avoided cost rates."[28] By taking into account the factors listed in the FERC's regulations and prior Commission orders, the Companies can more precisely tailor their avoided cost rates for QFs greater than 1 MW to the value that the individual QFs are providing to our customers, which will result in more accurate avoided costs and well-planned and coordinated integration of PURPA solar into the Companies' systems.

27 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 12-13, Docket No. E-100, Sub 66 (July 16, 1993).

28 *Order on Clarification*, at 3, Docket No. E-100, Sub 140 (March 6, 2015).

**Q. DO THE COMPANIES INTEND TO INCLUDE THE COSTS OF ANCILLARY GENERATION SERVICES OR OTHER SOLAR INTEGRATION COSTS IN THEIR CALCULATIONS OF AVOIDED COST RATES FOR QFs THAT ARE NOT ELIGIBLE FOR THE STANDARD OFFERS?**

A. The Companies believe that inclusion of these costs to calculate avoided cost rates for use in bilateral negotiations with QFs is appropriate and consistent with the FERC and Commission decisions discussed above. As part of bilateral negotiations with the Companies, the QFs may always request to review the inputs to DEC's or DEP's calculated rates; if a QF disagrees with the Companies' calculation of its avoided costs, the Commission has long provided that the parties are to negotiate in good faith and a QF may always file a complaint or petition the Commission to arbitrate the matter.

**Q. WOULD THE COMPANIES OPPOSE THE COMMISSION ESTABLISHING A NEW PROCEEDING TO EVALUATE THE MANNER IN WHICH THE COMPANIES DETERMINE THEIR AVOIDED COSTS FOR LARGE QFs?**

A. As discussed above, both FERC's regulations and prior Commission Orders have provided relatively clear guidance for the Companies to follow in developing their avoided cost rates for larger negotiated QFs. At this time, the Companies do not anticipate such a proceeding is required, as the Companies agree to identify the inputs to their avoided cost calculations for QFs as part of the negotiation process. However, if future arbitrations or complaints arise or the Commission otherwise determines that an additional formal or informal proceeding would be beneficial to resolve concerns regarding how the Companies calculate their avoided cost rates for large QFs, the Companies do not object.

## IV. <u>THE COMPANIES' PROPOSED LONG-TERM LEVELIZED SCHEDULE PP RATE STRUCTURE PROTECTS CUSTOMERS FROM THE GROWING RISKS OF OVERPAYMENTS</u>

**Q. PLEASE REINTRODUCE THE COMPANIES' PROPOSAL TO MODIFY THE SCHEDULE PP STANDARD OFFER CONTRACT TERM.**

A. As discussed in the Companies' Joint Initial Statement and in my pre-filed direct testimony, the Companies' proposed Schedule PP has been modified to a single 10-year long-term avoided cost standard contract with fixed capacity rates, but with energy rates to be updated every two years as part of the Commission's biennial review of the Companies' avoided costs. As I, along with Witness Snider, explained in direct testimony, this proposal has been designed in light of current economic and regulatory circumstances to pay small QFs eligible for the standard offer a levelized capacity value over the full 10-year term, while mitigating the significant forecast risk of over- or under-projecting long-term commodity prices. Specifically, the biennial adjustment of the energy component will more closely align future avoided energy cost payments with the Companies' actual avoided cost of energy, whether that energy cost is increasing or decreasing, and is designed to protect customers from over-paying for avoided energy in future years where fuel commodity forecasts are not as certain.

**Q. DOES THE PUBLIC STAFF SUPPORT THE COMPANIES' PROPOSED REDUCTION OF THE SCHEDULE PP TERM TO 10 YEARS?**

A. Yes. Public Staff Witness Hinton discusses this issue at pages 52-57 of his testimony and supports the Companies' proposed reduction of the Schedule PP term to 10 years, explaining "Due to the continued rapid pace of QF development in North Carolina, the Public Staff believes it is appropriate at this time for the Commission to consider a shorter-term structure for avoided cost rates."[29] Witness Hinton supports this recommendation by explaining that reducing the contract term will "serve to reduce the risk borne by ratepayers for overpayments over a longer term."[30] Indeed, Witness Hinton highlights the growing overpayment risk to customers multiple times throughout his testimony, emphasizing the "sheer volume of QF projects currently being developed in North Carolina from which the utilities are obligated to purchase the energy and capacity at avoided cost rates."[31]

**Q. DO OTHER INTERVENORS SUPPORT THE COMPANIES' PROPOSED REDUCTION OF THE SCHEDULE PP TERM TO 10 YEARS?**

A. NCSEA Witnesses Harkrader and Strunk, Cypress Creek Witness McConnell, and SACE Witness Vitolo all oppose the proposed reduction in the standard offer term to 10 years preferring the status quo be maintained. These

29 Public Staff Hinton Testimony, at 56.

30 *Id.*

31 Public Staff Hinton Testimony, at 7.

witnesses all generally allege that financing and development of QF projects will be more challenging under the Companies' proposal to reduce the standard offer term to 10 years. SACE Witness Vitolo also argues that the Commission should consider mandating the Companies to offer solar QFs fixed contracts of 20/25 years to match the recovery period of the respective utility's own solar PV assets.[32]

**Q. DOES THE PUBLIC STAFF SUPPORT THE COMPANIES' PROPOSAL TO RESET THE AVOIDED ENERGY RATE EVERY TWO YEARS IN FUTURE COMMISSION AVOIDED COST PROCEEDINGS?**

A. No. Public Staff Witness Hinton expresses concern that "resetting energy rates every two years for facilities eligible for the standard offer rates adds an additional element of uncertainty to their ability to reasonably forecast their anticipated revenue, which may make obtaining financing difficult or impossible."[33]

**Q. DO OTHER PARTIES SUPPORT THE COMPANIES' PROPOSAL TO RESET THE AVOIDED ENERGY RATE EVERY TWO YEARS IN FUTURE COMMISSION AVOIDED COST PROCEEDINGS?**

A. Consistent with their opposition to reducing the standard offer to a 10-year term, NCSEA, SACE, and Cypress Creek also oppose the Companies' proposal to biennially reset the avoided energy rates in future Commission avoided cost proceedings.

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32 SACE Vitolo Testimony, at 17.

33 Public Staff Hinton Testimony, at 58, 60.

NCSEA Witness Johnson raises concerns that QFs' revenue stream will become "highly unpredictable" and will depend not only on "the future course of volatile fuel prices" but also on "the outcome of litigated proceedings every two years."[34] NCSEA Witness Strunk and Cypress Creek Witness McConnell present similar views arguing that biennially resetting avoided energy rates every two years does not provide QF developers a reasonable opportunity to attract capital from potential investors. Witness Strunk suggests that "the proposed two-year energy price reset leads to a situation where lenders and equity investors will only be able to count on two (2) years of known energy revenues" such that "[a]ll energy revenues after the second year will be regarded by lenders and equity sponsors as risky and will be discounted accordingly."[35] Witness McConnell similarly argues that "[f]inancing parties would view a ten-year contract with a two year readjustment no more favorably than they would a two-year contract" which he alleges is not currently financeable.[36] Finally, SACE Witness Vitolo alleges that the Companies have not evaluated potential adverse impacts on the ability of solar QFs to obtain financing with energy rates recalculated every two years.

34 NCSEA Johnson Testimony, at 158.

35 NCSEA Strunk Testimony, at 15.

36 Cypress Creek McConnell Testimony, at 7.

**Q. PLEASE RESPOND.**

A. As discussed extensively in my direct testimony and the Companies' Joint Initial Statement, the combination of surging solar QF development and the recent deviation in market-based commodity costs compared to prior forecasts have resulted in customers being obligated for significant long-term over-payments compared to the Companies' current forecast of avoided costs. Witness Snider highlighted in our direct case that this overpayment could be as much as $1.0 billion over the term of existing PPAs for installed QFs, even before taking into account the approximately 1,100 MWs of proposed solar QFs in development that are eligible for the Commission's previous 2014 Sub 140 or 2012 Sub 136 standard offer avoided cost rates. Continuing existing policy or increasing the standard offer term, as proposed by SACE Witness Vitolo, would exacerbate the already significant overpayment risk for our customers in the future, which is no longer compatible with PURPA's mandate that avoided cost rates and policies shall be just and reasonable to utility customers and in the public interest.[37]

The Companies appreciate the Public Staff's recognition that reducing the standard offer term to 10 years, especially when combined with other modifications supported by the Public Staff, is reasonable and will serve to mitigate some overpayment risk in light of the current evolving economic and regulatory circumstances of surging solar QF development in North Carolina. However, the Companies continue to be concerned that long-term

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37 16 U.S.C. §824a-3(b)(1).

overpayment risk associated with forecasted commodity pricing may result in payments in excess of the Company's future incremental cost of alternative energy, which is inconsistent with PURPA.[38] Mandating that customers be assigned this risk is simply not just and reasonable to customers and in the public interest based upon recent levels of QF development.

**Q. HOW DO THE COMPANIES RESPOND TO ARGUMENTS THAT THEY DID NOT EVALUATE THE FINANCEABILITY OF THE PROPOSED STANDARD OFFER FOR SMALL SOLAR QFs?**

A. The Companies appreciate the Public Staff's and other parties' concerns that small QFs and their potential investors require certainty in terms of the avoided cost rates to be offered in order to determine whether to develop a project. As discussed in my prefiled direct testimony, the fact that North Carolina has experienced 60% of installed PURPA-driven solar generation nationally is clear evidence that continuing the status quo PURPA policies in North Carolina can result in significant additional QF solar development. Based upon current economic and regulatory circumstances, however, the Companies designed the Schedule PP avoided cost standard offer to provide reasonable encouragement of small QFs through a 10-year fixed avoided capacity rate while mitigating the risk of potential overpayment associated with long-term commodity forecasts. In presenting this proposal to the Commission, the Companies' focus was on mitigating the recently-experienced long-term overpayment risks to customers. Biennially resetting

38 16 U.S.C. §824a-3(d).

avoided energy cost rates based upon future avoided energy rates approved by the Commission every two years is a just and reasonable mechanism to accomplish this objective.

Further, as highlighted in my direct testimony and recognized by Public Staff Witness Hinton, the Companies evaluated the standard offer rates approved in other southeastern states, as well as reviewed how other states such as Idaho have responded to significant PURPA development in those jurisdictions.[39] Notably, only NCSEA Witness Johnson commented on how PURPA is being implemented across the country and throughout the southeast, effectively recognizing that North Carolina's implementation of PURPA has significantly encouraged unprecedented QF development compared to other states.[40] The other Intervenor witnesses have largely focused only on maintaining status quo policies in North Carolina.

Finally, I also note that FERC's PURPA regulations have long provided a method through 18 C.F.R. 292.302 for QF investors to evaluate the utility's longer-term need for capacity and forecasted cost of energy. This section of FERC's regulations requires the utilities to biennially file forecasted electric utility system cost data for both energy and capacity with the Commission. As explained by FERC in Order No. 69, this data can then be

39 Public Staff Hinton Testimony, at 58.

40 NCSEA Johnson Testimony, at 25-26.

used by QFs and their investors in evaluating the utility's future avoided costs.[41]

**Q. DOES A STANDARD OFFER THAT INCLUDES BIENNIALLY RESETTING AVOIDED ENERGY RATES EVERY TWO YEARS PROVIDE QF DEVELOPERS A REASONABLE OPPORTUNITY TO ATTRACT CAPITAL FROM POTENTIAL INVESTORS?**

A. In my current role at Duke Energy, I have not had occasion to become an expert on the contract terms and conditions that the financial community would deem "reasonable" or that are otherwise minimally necessary to allow for attraction of the capital needed to encourage QF development. My general understanding is that numerous factors including a QF developer's balance sheet, management team experience and creditworthiness, as well as avoided cost-specific considerations including price, contract tenor, the cost of capital, and the risk of the investment, amongst others, all come into play in determining whether an investment can attract debt and/or equity capital. Witness Hinton's comments that smaller QFs eligible for the standard offer may need greater certainty with regard to securing capital and return on investment than larger QFs seems reasonable.[42] I would also highlight that, unlike the cost-of-service-based rates of electric utilities like DEC and DEP, PURPA largely exempts QFs from state regulatory authority oversight of their rates and business operations so that neither the Companies, the Public Staff,

41 *Order No. 69, supra* note 14, at 19 (discussing 18 C.F.R. 292.302).

42 Public Staff Hinton Testimony, at 59-60.

nor the Commission has any clear insights into a QF developer's business or the level of profit deemed "reasonable" to attract equity capital.[43]

I am, however, aware that FERC recently issued a declaratory Order[44] in response to an enforcement petition by 26 solar QFs ("Windham Solar QFs") presenting its view (but not taking enforcement action) that the Connecticut Public Utility Regulatory Authority's ("PURA") implementation of PURPA was inconsistent with FERC's regulations because the purchasing utility's approved avoided cost tariff offered QFs only the ISO-New England real-time energy price. The Windham Solar QFs argued that offering this single real-time pricing energy-only rate was inconsistent with the QFs' right under 18 C.F.R. 292.304(d)(2) of FERC's regulations to commit to deliver power pursuant to a legally enforceable obligation based upon a forecasted avoided cost rate. In determining that the Windham Solar QFs had a right under PURPA to elect to sell power pursuant to a legally enforceable obligation at a forecasted avoided cost rate, the *Windham Solar Order* made three findings (only one of which is cited by intervenors in this case),

- FERC's regulations provide that a state regulatory authority may establish lower avoided cost rates for purchases from intermittent QFs than for purchases from firm QFs, recognizing factors which include, among others, the availability of capacity, the QF's dispatchability,

43 *See* 18 C.F.R. § 292.601 (2017) (exempting QFs under 30 MW from most sections of the Federal Power Act); 18 C.F.R. § 292.602 (exempting QFs under 30 MW from the Public Utility Holding Company Act of 2005, 42 U.S.C. 16,451-63 and state laws and regulations on electric utility rates and financial and organizational regulation of electric utilities).

44 *Windham Solar, LLC*, 157 FERC ¶ 61,134 (2016) ("Windham Solar Order").

the QF's reliability, and the value of the QF's energy and capacity. (P. 6);

- QFs may be able to provide capacity to utilities in restructured power markets, such as ISO-New England, including the possibility of the utility offering QF capacity into the market. (P. 7);
- Given the QF's need to enter into contractual commitments based upon estimates of future avoided costs and the need for certainty with regard to return on investment, PURPA's directive to "encourage" QFs suggests that a legally enforceable obligation should be "long enough to allow QFs reasonable opportunities to attract capital from potential investors." However, FERC reiterated that its regulations do not specify a particular number of years for such legally enforceable obligations, meaning that the term and structure of forecasted avoided cost rates is left to the discretion of the implementing State Commission. (P. 8, Fn. 13).

**Q. SHOULD THE *WINDHAM SOLAR ORDER* MATERIALLY CHANGE THE COMMISSION'S ANALYSIS OF THE COMPANIES' PROPOSED STANDARD AVOIDED COST RATES OFFERED IN NORTH CAROLINA UNDER PURPA?**

A. No, it should not. The Commission's mandate under PURPA continues to be focused on ensuring that DEC's and DEP's avoided cost rates are just and reasonable to consumers and in the public interest, not discriminatory against QFs, and do not exceed the cost of the energy the utility would have incurred through self-generation or otherwise, but for the purchase from the QF.[45] Notably, this decision arose based upon Connecticut's implementation of PURPA within the organized ISO-New England wholesale power market, where that State's purchasing utilities offered only a real-time energy avoided cost rate and did not recognize that QFs could meet future capacity needs (or offer to pay the QF for capacity). In contrast, the Companies' Schedule PP rate is designed to pay QFs for capacity during the 10-year Schedule PP term where DEC's or DEP's biennial IRP identifies that a future capacity need can be avoided by QF power. Specific to avoided energy value, the *Windham Solar Order* does not suggest that the ISO-New England market-based value of energy is not an appropriate methodology to establish the future avoided energy value of QF power in Connecticut.

The Companies are also aware of only one other jurisdiction outside of an organized wholesale market that has considered FERC's recent guidance in the *Windham Solar Order* in setting forecasted avoided cost rates to implement PURPA. In early March, the Alabama Public Service Commission approved Alabama Power Company's ("Alabama Power") standard offer rate for QFs with a design capacity above 100 kW, which offers Alabama Power's forecasted avoided energy and capacity rate over a one-year term with an "evergreen provision" under which avoided cost pricing "updates annually consistent with the updated avoided energy pricing submitted by the

45 *See* 16 U.S.C. §§ 824a-3(b), (d).

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Company."[46] The Alabama PSC held this rate structure continued to be consistent with PURPA and the FERC's prior guidance that a "long-term contract" in the context of PURPA is "one year or longer."[47]

In light of the distinguishable facts and circumstance underlying the Connecticut PURA's implementation of PURPA in ISO-New England as well as limited regulatory developments outside of an organized wholesale market since the *Windham Solar Order*, the Companies do not view FERC's guidance as materially affecting the Commission's analysis of whether the Companies' proposal is a reasonable implementation of DEC's and DEP's obligation to purchase from QFs under PURPA.

**Q. DO THE COMPANIES SUPPORT THE PUBLIC STAFF'S "ALTERNATIVE PROPOSALS" TO MITIGATE FUTURE AVOIDED ENERGY FORECAST RISK FOR CUSTOMERS WHILE PROVIDING ADDITIONAL CERTAINTY FOR SMALL STANDARD OFFER QFs?**

A. Potentially. While Witness Hinton does not support the Companies' proposal to biennially reset avoided energy cost rates for small QFs, he does signal that the Public Staff would be open to "other options" to mitigate the potential overpayment risk for customers such as "linking available energy rates to a publicly available composite fuel index or establishing a band or collar on the amount of adjustment that energy rates could vary from some indicative

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46 *Alabama Power Company, Petition: For approval of Rate CPE -- Contract for Purchased Energy*, Docket No. U-5213 (March 7, 2017).

47 *Id. Citing See New PURPA Section 210(m) Regulations Applicable to Small Power Production Facilities and Cogeneration Facilities, Order No. 688-A*, 119 FERC P 61,305, at P 27 & n.17 (2007).

pricing."[48] NCSEA Witness Johnson similarly seems to support Public Staff Witness Hinton's alternative concept of linking the future avoided energy rate to "a published fuel price index," further agreeing with Witness Snider that this approach is "inherently less risky and more predictable [than the outcome of biennial litigation] and is typical practice in the industry."[49]

The Companies have not had sufficient opportunity to fully analyze these alternative proposals, but believe there is merit in evaluating whether linking avoided energy rates to a publicly available composite fuel index could mitigate future energy commodity cost risk for customers while also providing additional certainty to small QFs and their investors. Such proposals may also be reasonable for larger negotiated QF agreements to the extent a fuel index-based contract structure could mitigate the inherent inaccuracy in long-term commodity price forecasts. The Companies plan to evaluate these potential alternative proposals for small QFs between now and the next biennial avoided cost proceeding. During this period, the Companies may also gain additional experience as larger QFs seek to negotiate longer contract tenors, and the Companies continue to evaluate the most appropriate rate structures that accurately values QF energy, thereby mitigating the long-term overpayment risk for customers.

48 Public Staff Hinton Testimony, at 60.

49 NCSEA Johnson Testimony, at 159.

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**Q. FOR PURPOSES OF THIS PROCEEDING, DO THE COMPANIES RECOMMEND IMPLEMENTING ANY "ALTERNATIVE PROPOSALS" TO MITIGATE FUTURE AVOIDED ENERGY FORECAST RISK FOR CUSTOMERS WHILE PROVIDING ADDITIONAL CERTAINTY FOR SMALL STANDARD OFFER QFs?**

A. Yes. The Companies have determined that offering small standard offer QFs the option to "fix" the 2-year avoided energy rate for the full 10-year term is an appropriate compromise in response to the testimony offered by Public Staff Witness Hinton, NCSEA Witness Strunk, and Cypress Creek Witness McConnell that small QF investors will view energy revenues in years beyond the proposed biennial update as risky and that a longer-term fixed rate (seemingly for both energy and capacity) is needed by smaller QFs in order to attract capital. As explained in my direct testimony, the biennial reset of the avoided energy component was designed to – and will remain an available option to – more closely align future avoided energy cost payments with the Companies' actual avoided cost of energy, whether that energy cost is increasing or decreasing. Selecting this option could provide QFs the potential upside benefit of increased rates if energy prices increase above the proposed 2-year rate during the 10-year contract term. However, to the extent QF developers prefer to "fix" current energy commodity prices for the full 10-year contract term, the Companies believe such an option is reasonable at this time and will protect customers from long-term forecast risk by relying on near-term energy commodity pricing underlying the 2-year avoided energy rate. The Companies propose to modify their Schedule PP tariffs within 10 business days of a Commission Order approving this additional option.

**Q. DO THE COMPANIES VIEW THIS ALTERNATIVE OPTION AS A LONG-TERM SOLUTION?**

A. No. As discussed above, the Companies commit to reevaluate this rate design option in the next biennial avoided cost proceeding along with the alternative options identified by the Public Staff.

**Q. PLEASE RESPOND TO SACE WITNESS VITOLO'S ARGUMENT THAT THE COMMISSION DENIED A SIMILAR BIENNIAL RESET OF THE AVOIDED ENERGY RATE FOR DNCP IN THE 2010 SUB 127 PROCEEDING.**

A. SACE Witness Vitolo suggests that the Commission previously addressed a similar proposal by DNCP in the 2010 avoided cost proceeding, E-100 Sub 127, and states that the Commission held that DNCP's proposed biennial reset of its energy rate was inconsistent with a QF's right to a long-term rate under FERC's *J.D. Wind* Orders.[50] As an initial matter, the Companies note that DNCP had used the biennial reset method from 1989 to 2010 prior to the Commission directing that company to transition to fixed, levelized avoided energy rates for the full contract term in the next biennial avoided cost proceeding.[51] For reasons similar to those argued by DNCP in that

50 SACE Vitolo Testimony, at 22, *citing J.D. Wind 1, LLC*, 130 FERC ¶ 61,127 (2010), *denying reh'g*, 129 FERC ¶ 61,148 (2009) (*J.D. Wind*).

51 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 127 at 9-10 (July 27, 2011) ("Sub 127 Order").

proceeding, the Companies do not believe that PURPA or FERC's regulations prohibit a biennial energy rate reset as a fixed-formula rate.[52]

Further, the Companies have developed the proposed Schedule PP rate design in light of current economic and regulatory circumstances to balance a QF's desire for long-term capacity payments with mitigating the significant energy commodity price forecast risk through a biennially re-established energy rate. Precluding such alternative formula-fixed rate options will not serve the public interest under PURPA, and will inevitably lead to shorter "fixed-rate" capacity and energy contract structures in the future. It also continues to cause North Carolina to be an outlier that significantly encourages QF development compared to other southeastern states, including "Alabama, Arkansas, Florida, Kentucky, Louisiana, Maryland, and Virginia [which] offer variable, rather than fixed long term rates" as discussed by NCSEA Witness Johnson.[53]

The Companies also note that while the Commission ultimately directed DNCP to begin forecasting a 15-year levelized rate in the next

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52 *Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities*, FERC 1988-1998 Proposed Regulation Binder ¶ 32,457 at 32,171 (as quoted in *Reply Comments of Dominion North Carolina Power* at 9-10, Docket No. E-100, Sub 127 (Apr. 4, 2011)) (holding that a "fixed price contract" may include "any legally enforceable obligation wherein the rates for purchase by a utility of the power produced by a QF are established in advance of the purchase. The fixed price may be a single, uniform rate for kilowatt or kilowatt hour for all power, including a fixed formula rate, or a complex schedule of time-differentiated rates and other payments. The contracts term may range from decades to months."); *see also Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities,* Notice of Proposed Rulemaking, at 65 Docket No. RM88-6-000 (March 16, 1988) ("…a contract could provide QFs with a price floor applicable to all the power supplied to the utility, but still provide for higher variable unit prices reflecting daily or seasonal periods. The price floor would provide the revenue stream necessary for the QF to secure financial support … ***a contract could provide for a two-part price—a fixed payment for capacity and an energy price for power delivered***. The QF would be assured a minimum revenue stream based on the value of its capacity.") (emphasis added).

53 NCSEA Johnson Testimony, at 25.

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biennial proceeding, the *Sub 127 Order* approved DNCP's continued use of a 2-year fixed energy rate for the Sub 127 vintage standard offer.[54] Accordingly, approval of the Companies' alternative option discussed above to fix its 2-year energy rate for purposes of this proceeding seems equally as "fixed" as DNCP's avoided cost rates in effect from 2010-2011 pursuant to the *Sub 127 Order*.

**Q. FINALLY, IS SACE WITNESS VITOLO'S COMPARISON OF QF FIXED CONTRACTS AND UTILITY GENERATING ASSETS REASONABLE?**

A. No. As noted above, SACE Witness Vitolo argues that the Commission should consider mandating the Companies to offer solar QFs fixed contracts of 20/25 years to match the longer recovery period of the Companies' own solar PV and other generating assets.[55] However, QF contracts are distinct from utility-owned generation in multiple ways. First, utility generating resource additions are driven by need: the Companies are not compensated by customers for energy produced from generating facilities until they establish the need for new generation through an extensive IRP process and the Commission approves a CPCN determining the facility is the least-cost resource to fill the need. In contrast, the PURPA must-purchase requirement mandates QFs must be reimbursed for selling power to the Companies whether or not the power is needed. Further, because utility load-following generating resources are dispatchable, they can be backed down when more

54 Sub 127 Order, at 10.

55 SACE Vitolo Testimony, at 17.

economic alternatives are available. Also, because utilities are not locked in to long-term fixed contracts, they can pass lower fuel and other operating costs savings to customers. In contrast, a utility cannot dispatch or back down a QF when more economic alternatives are available, so customers ultimately pay for potentially higher-cost QF energy produced by a QF. This inefficiency is exacerbated when long-term QF contracts are in effect. Finally, the full avoided cost rates that QFs are entitled to receive are not related to the cost of the PURPA project, whereas capital costs of utility generating assets are determined based upon cost and recovered over their depreciable useful lives. I do not anticipate that QFs would actually advocate for a longer cost recovery period based upon their cost of service; only to extend the period of guaranteed revenue (and profit) out into the future.

## V. THE COMPANIES' CALCULATION OF ITS AVOIDED CAPACITY COSTS APPROPRIATELY ACCOUNTS FOR THEIR RELATIVE NEED FOR CAPACITY

**Q. PLEASE EXPLAIN THE COMPANIES' PURPOSE FOR RECOMMENDING CAPACITY CREDITS THAT ACCOUNT FOR THE RELATIVE NEED FOR GENERATING CAPACITY.**

A. Witness Snider will discuss this issue in more detail, but, as I noted in my pre-filed direct testimony, the Companies propose this adjustment to the avoided capacity cost calculations because our customers should not be required to pay for capacity in years in which the Companies have already built or procured sufficient capacity to serve customers, and, therefore, have no need for additional capacity. PURPA was not intended to force a utility to pay for capacity that it otherwise does not need.

**Q. DO THE OTHER INTERVENORS AGREE WITH THE COMPANIES' POSITION?**

A. Public Staff Witness Hinton agreed with the Companies' position on this issue, explaining "[b]y restricting the payment until the IRP has established a capacity deficiency will minimize the overpayment risk to ratepayers, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market."[56] NCSEA Witness Johnson and SACE Witness Vitolo again urge the Commission to maintain the status quo. They both cite the Commission's previous decision in the Sub 140 proceeding as support of their arguments that the Companies' avoided capacity cost rates should not be reduced when the utility shows no need to acquire QF capacity.[57]

**Q. IS THE COMPANIES' PROPOSAL CONSISTENT WITH PURPA?**

A. Yes. FERC has long held that "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity . . . [the purchase] obligation does not require a utility to pay for capacity that it does not need."[58] FERC has also expressly stated that "there is no obligation under PURPA for a utility to pay for capacity that

56 Public Staff Hinton Testimony, at 14.

57 NCSEA Johnson Testimony, at 183; SACE Vitolo Testimony, at 29-30.

58 *City of Ketchikan,* 94 FERC ¶61,293 (2001) ("*Ketchikan") citing Order No. 69, FERC Stats. & Regs., Preambles 1977-1981* P30,128 at 30,865.

would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for that capacity.[59]

More recently, in *Hydrodynamics*, FERC reiterated that "when the demand for capacity is zero, the cost for capacity may also be zero"[60] but, based upon the specific facts of that case, held that a state rule which precluded QFs from receiving "forecasted avoided cost rates" once the utility's QF capacity purchases reached an arbitrarily set 50 MW cap was inconsistent with FERC's avoided cost regulations.[61] FERC distinguished its criticism of this state rule from the factual circumstances at issue in the prior *Ketchikan* decision because the 50 MW limit in *Hydrodynamics* was not related to the utility's actual capacity needs.[62] As Public Staff Witness Hinton notes in this proceeding, DEC's and DEP's next actual capacity needs under the Companies' respective IRPs are in 2022/2023 and 2021/2022 timeframes.[63] Accordingly, DEC and DEP should not be obligated to pay for capacity during this "capacity sufficient" period before the need arrives.

**Q. PLEASE RECONCILE THE COMPANIES' PROPOSAL WITH THIS COMMISSION'S DECISION TO PAY QFs FOR AVOIDED CAPACITY IN THE SUB 140 PROCEEDING.**

59 *Id.*

60 *Hydrodynamics, Inc.*, 146 FERC ¶ 61, 193 at P 35 (2014).

61 *Id.* at P. 34.

62 *Id.* at P. 35.

63 Public Staff Hinton Testimony, at 14-15.

A. In the Sub 140 proceeding, the Commission exercised its discretion in setting avoided cost rates not to authorize a capacity rate reduction based on a utility's near-term lack of capacity need "as a generic principle." However, as Public Staff Witness Hinton notes, "the sheer volume of QF projects currently being developed in North Carolina . . . is unparalleled."[64] Thus, the Public Staff supports the Companies' proposal to limit capacity payments until their respective IRPs identify a capacity need.[65] The Companies, likewise, request that the Commission reconsider this determination and approve its proposal in light of these evolving economic and regulatory circumstances.

## VI. CIRCUMSTANCES WHERE VIOLATIONS OF NERC/SERC STANDARDS ARE IMMINENT ARE "SYSTEM EMERGENCIES" THAT JUSTIFY EMERGENCY CURTAILMENT

**Q. PLEASE DESCRIBE THE COMPANIES' AMENDMENT TO THEIR STANDARD OFFER TERMS AND CONDITIONS WITH RESPECT TO BEING ABLE TO CURTAIL QF GENERATION IN A SYSTEM EMERGENCY.**

A. The Companies have proposed to amend paragraph 14 of their Terms and Conditions to provide notice that an emergency condition justifying curtailment of QF generation includes any circumstance that requires action by the Companies to comply with mandatory NERC/SERC regulations, such as the BAL standards, which Witness Holeman discusses in more detail.

**Q. WHAT IS THE PUBLIC STAFF'S POSITION ON THIS ADDITION TO THE COMPANIES' TERMS AND CONDITIONS?**

64 Public Staff Hinton Testimony, at 7.

65 Public Staff Hinton Testimony, at 14.

A. After discussing in detail the unique challenges from increasing amounts of PURPA "must-take" and non-dispatchable generation that the Companies face, Public Staff Witness Metz agreed that potential imminent violation of a BAL standard is an emergency that would justify curtailment of QF purchases and recommends that the Commission make explicit findings to that effect.[66] The Public Staff further recommended that the Companies file its curtailment guidance with the Commission, along with requirements on how curtailment events would be reported, and what information would be included in each report. As noted by Witness Holeman, the Companies agree with these recommendations and are currently in the process of refining their processes with respect to QF curtailment. The Companies also intend to continue their discussions on our non-discriminatory processes and procedures for curtailing both Companies' facilities and QFs in system emergencies with the Public Staff as soon as they are complete.

**Q. IS THE COMPANIES' PROPOSED CLARIFICATION OF SYSTEM EMERGENCIES CONSISTENT WITH PURPA AND IN THE PUBLIC INTEREST?**

A. Yes. As discussed in my direct testimony and identified by Public Staff Witness Metz, FERC's regulations permit a utility to discontinue purchases during system emergencies if such purchases would contribute to such

66 Public Staff Metz Testimony, at 13-14 (recommending the Commission "affirm that utilities have the authority to curtail QFs during system emergencies, explicitly find that imminent violations of the NERC BAL Standards constitute system emergencies, and further investigate how to provide stakeholders clarity on curtailments made due to system emergencies.").

emergencies.[67] This curtailment must be done on a nondiscriminatory basis. Second, the Companies agree with Public Staff Witness Metz that an imminent violation of a BAL standard is a system emergency that could result in significant service disruptions to our customers. Therefore, the proposed clarification serves the public interest.

**Q. IS NCSEA WITNESS JOHNSON'S RECOMMENDATION FOR "TAKE OR PAY" CONTRACTS A VIABLE ALTERNATIVE TO CURTAILING QFs IN AN EMERGENCY?**

A. No, it is not. The Companies strongly disagree that the Commission should adopt a recommendation that results in our customers paying for QF solar power that is simply "discarded" or not used to meet system load. Witness Johnson provides no evidence that any other public service commission has ever approved such a contract in its implementation of PURPA, and it seems completely unjust and unreasonable to mandate such a proposal in North Carolina based upon current economic and regulatory circumstances. Further, nothing in PURPA requires customers to pay QFs for unused or unneeded energy or capacity, as FERC confirmed in establishing its regulations in Order No. 69:

> "A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, ***the purchase rate should only include payment for the energy or capacity which the utility can use to meet its total system load***. These rules impose no

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67 18 C.F.R. 292.307(b).

> requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale."[68]

## VII. THE COMPANIES DO NOT SUPPORT DEVELOPING A STANDARD OFFER SOLAR SPECIFIC RATE IN THIS PROCEEDING, BUT AGREE THAT SUCH A PROPOSAL MAY BE REASONABLE IN THE FUTURE

**Q. HAVE OTHER PARTIES RECOGNIZED THAT THE COSTS AVOIDED BY SMALL SOLAR QFs MAY BE DIFFERENT THAN OTHER QF GENERATORS, AND SUGGESTED THAT IT WOULD BE APPROPRIATE TO DEVELOP SOLAR QF-SPECIFIC AVOIDED COST RATES?**

A. Yes. Both Public Staff Witness Hinton and NCSEA Witness Johnson recommend that the Utilities should be required to establish solar QF-specific avoided energy rates. Witness Hinton focuses on a single issue – limiting the off-peak avoided energy profile of solar QFs to daytime hours – to suggest that a separate avoided energy rate for small solar QFs should be developed.[69] Witness Johnson more generally recommends "the Commission initiate steps to provide stronger, more precise peak and off peak price signals in the QF tariffs" and identifies that price signals may be used to better address the Companies' growing concerns about operationally excess energy.[70]

**Q. PLEASE RESPOND.**

A. Consistent with prior biennial avoided cost proceedings, the Companies have developed "generic" standard offer rates that would be available to all non-

68 Order No. 69, *supra* note 14 at 25-26. (emphasis added).

69 Public Staff Hinton Testimony, at 63-64.

70 NCSEA Johnson Testimony, at 197-98.

hydroelectric small QFs now capped at 1 MW or less. In designing the Schedule PP rates, the Companies relied upon traditional application of the peaker methodology and did not focus on either the specific energy-related or capacity-related characteristics of a small solar QF or other type of small QF generator. As I explained earlier and as further discussed by Witness Snider, capping eligibility for the standard offer at 1 MW will allow the Companies to more precisely determine the avoided energy and capacity value attributable to larger utility-scale QFs, including solar QFs, in the future based upon a QF's specific characteristics. FERC's regulations have long recognized that the specific characteristics of a QF's power may be considered in setting rates for individual QFs (18 C.F.R. 292.304(e)). FERC also recently reiterated that "the availability of capacity, the QF's dispatchability, the QF's reliability, and the value of the QF's energy and capacity" may be taken into account in setting avoided cost rates.[71] Importantly, however, the Companies do not believe it is appropriate in this proceeding to consider only one individual aspect of a small solar QF's avoided energy value without considering other specific characteristics of a QF technology.[72] Notably, the Public Staff identified other considerations, including integration costs and line losses that are not being taken into account, among others, in the Schedule PP rate design. To the extent a small solar QF believes it has greater value in off-peak

71 *Windham Solar Order*, *supra* note 36, at P. 6.

72 *Order Setting Avoided Cost Input Parameters*, Docket No. E-100, Sub 140 (recognizing that "proposal isolates one potential benefit of solar generation but fails to account for any of the potential costs inherent in such intermittent resources.").

hours than currently being recognized in the Schedule PP rate, that QF can request to negotiate a PPA that more accurately and completely reflects its current avoided costs. The Companies also agree that it may be reasonable in the next avoided cost proceeding to consider a small solar-specific QF avoided cost rate design if all avoided costs and potential benefits of incremental solar QF generation on the Companies' systems are taken into account.

## CONCLUSION

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

A. Yes, it does.

BY MS. FENTRESS:

Q Ms. Bowman, do you have a summary of your direct and rebuttal testimonies?

A Yes.

Q Would you please present that for the Commission?

A Sure.

(WHEREUPON, the summary of **KENDAL C. BOWMAN** is copied into the record.)

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
Summary of Kendal Bowman's Direct and Rebuttal Testimony
NCUC Docket No. E-100, Sub 148

My Direct Testimony supports the Companies' proposed standard offer avoided cost rates and tariffs presented in the November 15, 2016 Joint Initial Statement. I address how the unprecedented growth of solar qualifying facilities or "QFs" in the Companies' service territories is driving the need for a comprehensive review of the Commission's policies implementing the Public Utility Regulatory Policies Act ("PURPA"). My Direct Testimony provides a brief narrative on the history and requirements related to avoided cost rates and also provides an overview of the economic and regulatory circumstances requiring the Companies' proposed modifications to the approved avoided cost calculation methodology.

Since its enactment in 1978, PURPA has granted QFs the right to interconnect to the electrical grid and to sell their electrical output to the interconnecting public utility. This mandate includes a requirement that utilities offer to purchase the QF's output – either through a Standard Offer rate (which is the focus of this proceeding) or negotiated contract – at its "incremental cost of alternative electric energy," more generally referred to as the electric utility's "avoided cost." Over the past 35 years, the Commission has exercised the flexibility afforded by the Federal Energy Regulatory Commission's regulations in setting North Carolina's PURPA policies. Beginning with the Commission's initial proceeding in 1981, the Commission has applied its expert judgment to balance encouragement of QF development with achieving the public interest and mitigating potential harm to ratepayers through setting just and reasonable PURPA rates and policies. The Commission has adjusted the utilities' PURPA rates and standard offer terms on a number of occasions in response to changing economic, regulatory, and policy developments. Since 2005, however, the Commission's implementation of the PURPA standard offer has remained relatively unchanged, and has significantly encouraged QF development by offering renewable generators up to and including 5 MW standard rate options for a maximum 15-year term.

While North Carolina's PURPA policies have remained relatively unchanged over the past decade, the economic and regulatory circumstances related to utility-scale solar development in North Carolina have changed drastically in a very short time. My Direct Testimony details the dramatic increase in installed utility-scale solar capacity over the past five years. I report that installed utility-scale solar QF capacity in the DEC and DEP service territories increased from 125 MW in 2012 to 1,600 MW at the end of 2016. My Direct Testimony also explains that this surging QF growth has continued unabated since the Commission last reviewed its PURPA polices in 2014-2015 in Docket No. E-100, Sub 140. During this period, the number of proposed QF solar projects either under construction or in development and requesting to interconnect and sell power to the Companies has doubled, from approximately 2000 MW in 2015 to 4,900 MW by the end of 2016.

My Direct Testimony next outlines why PURPA is the predominant driver of solar development in North Carolina, as compared to other states. It is undisputed in this proceeding that sixty percent of all installed PURPA solar nationwide is located in North Carolina and that North Carolina is second only to California in installed solar capacity. My testimony attempts to answer "why?" by explaining that the price level and term of avoided cost rates calculated under the Commission's currently-effective PURPA policies, the low threshold to establish a legally enforceable obligation to sell QF power, as well as the current longer fixed terms for PURPA standard contracts for generators up to 5 MW has made North Carolina a significantly more favorable solar development marketplace than other states in the Southeast. This surging QF solar growth is projected to continue. In the past two years, the Commission has approved more than 350 applications for certificates of public convenience and necessity to construct QF solar generators between 4 and 5 MWs within DEC's and DEP's service territories, with most being heavily concentrated in the DEP East service territory. As the North Carolina Renewable Energy Tax Credit has expired and the Companies have increasingly procured sufficient resources to meet their Renewable Energy and Energy Efficiency Portfolio Standard requirements, North Carolina's implementation of PURPA is now the predominant driver of the continuing surge in solar QF development in our state compared to other states in the southeast and around the country.

My testimony then describes the long-term financial impacts of this surging solar QF growth on our customers, as hundreds of 5 MW QFs have recently locked into fixed long-term forecasted avoided cost rates for contracts spanning up to 15-year terms. As the Commission has recognized in the past, when QFs entitled to long-term Standard Offer rates are no longer of "limited number and size" the overpayment risk for customers increases significantly. Witness Snider has projected the financial impact of the existing, interconnected PURPA solar for the Companies' customers is approximately $2.9 billion over the next 12-14 years, and that our customers risk $1.0 billion in long-term overpayment to the QFs, when compared to the Companies' current calculation of avoided cost rates proposed in this proceeding. I also specifically highlight that an additional approximately 1,100 MW of proposed QFs still in development have locked into the avoided cost rates approved by the Commission in prior dockets to be paid over the next 15 years. This is significant both because it means that Witness Snider's $1.0 billion in long-term overpayment risk is very conservative and also because the Companies' proposed avoided cost changes in this proceeding will apply only to future purchases from QFs developed after these 1,100 MWs. Under PURPA, neither the Companies nor the Commission have the ability to modify these now contracted-for rates to provide our customers the benefit of the recently-experienced declines in natural gas and other commodity prices, as discussed by Witness Snider. This current and future significant overpayment risk is a key driver supporting the Companies' proposed avoided cost rates, including the biennial update to avoided energy rates.

My Direct Testimony then outlines the Companies' proposals to evolve the current PURPA standard offer policies to reflect the current economic and regulatory circumstances and to assure that avoided cost rates are just, reasonable and consistent with the public interest and the State's energy policies. The Companies' recommended modifications include:

- Lowering the eligibility limit for the Schedule PP standard avoided cost rate tariffs from 5 MW to 1 MW for non-hydroelectric generators.
- Transitioning to a single, 10-year long-term standard contract with fixed, levelized capacity rates and energy rates that are adjusted by the Commission every two years to better mitigate the significant risk of overpayment by customers compared to current avoided costs. Witness Glen Snider also discusses this proposal in his testimony.

- Reducing the Performance Adjustment Factor ("PAF") from 1.2 to 1.05 to more precisely reflect the reliability of a Combustion Turbine, addressed more fully by Witness Snider.
- Amending the Terms and Conditions to include as an "emergency condition" those circumstance that require action by the Companies to comply with NERC/SERC regulations, as explained further in Witness Sam Holeman's testimony.
- Modifying the Commission's current implementation of the Legally Enforceable Obligation ("LEO") concept to require an actual legally enforceable commitment by QFs to sell, thereby more appropriately allocating the risk of non-performance to QFs and better aligning the avoided cost rates paid to the QF with the value received by our customers. Witness Gary Freeman provides additional detail on that proposal.

Finally, I discuss how the Companies' proposals represent an important and necessary first step in a transition to a more "well-planned and coordinated" process, one that balances PURPA's goal of encouraging QF development with the dual challenges of integrating solar into our system and aligning the costs our customers ultimately pay for solar QF power with the value they receive. The Companies recognize that additional proceedings may be necessary to transition North Carolina towards a smarter, more sustainable renewable energy future. For example, the Companies support a competitive solicitation procurement model for utility-scale renewable resources, which the Companies believe will lower costs for customers, provide significant operational controls to the Companies, and open a new market for solar facilities outside of PURPA.

My Rebuttal Testimony addresses arguments made by other parties in response to the Companies' recommendations to evolve North Carolina's implementation of PURPA to reflect current economic and regulatory circumstances in the State. Specifically, I disagree with NCSEA Witness Johnson that the Companies' proposals are intended to stop solar development in North Carolina; instead, the proposals are intended to address two critical issues: the increasing risk of overpayments for PURPA solar power by our customers and the increasing challenges of planning and operating our systems reliably as significant additional QF solar is installed. While PURPA is intended to encourage QF development, its avoided cost provisions should operate as a ceiling, not a pricing floor for QF purchases.

In response to concerns about reducing the eligibility cap for standard avoided cost contracts, I explain why a 1 MW cap is more appropriate than a 3.75 or 4 MW cap or maintaining the status quo, which were recommended by NCSEA Witness Johnson and SACE Witness Vitolo respectively. A 1 MW cap is consistent with PURPA, better reflects current conditions and would better protect our customers from the risk of overpayment. Eliminating the incentive to "disaggregate" and arbitrarily develop 5 MW solar projects may actually improve economies of scale if solar developers transition to developing larger projects. And adjusting the cap should not result in protracted and costly power purchase agreement ("PPA") negotiations. The Companies have standardized PPA terms and conditions for larger QFs and intend to streamline the process further, as discussed by Witness Freeman.

I address various arguments opposing the Companies' proposed 10-year standard offer PPA rate design, including the biennial updating of the avoided energy rate.

Specifically, adjusting the Companies' avoided energy rates every two years as part of a longer fixed-term PPA appropriately balances the need to encourage QF development with the significant risk of overpayments now being experienced by our customers. To address concerns about small QFs' ability to attract investors, I also present a compromise "alternative option" that would allow small QFs eligible for the standard offer to fix the two-year energy rate for the full 10-year term as an interim solution while the Companies evaluate options proposed by Public Staff Witness Hinton to mitigate the risk of overpayment by customers between now and the next biennial proceeding. In response to SACE Witness Vitolo's argument that the Commission should approve PPA terms of 20-25 years, to match the longer recovery period of the Companies' own solar PV and other generating assets, I point out that the Companies' generating resource additions are driven by need and require Commission approval as the least-cost resource that can fill the need; that the Companies' resources are dispatchable and can be backed down when more economic alternatives are available; and, most importantly, that because utilities are not locked in to long-term fixed contracts, they can pass lower fuel and other operating cost savings to customers.

I also provide legal justification for recognizing the capacity value only in those years in which the Companies' IRPs show an actual capacity need, which is discussed in more detail by Witness Snider.

I also discuss the Companies' proposed modification to the standard offer terms and conditions to allow non-discriminatory curtailment of QF energy during system emergencies, which is discussed in more detail by Witness Holeman.

Finally, I address the Public Staff's recommendation that the Commission direct the Companies to develop a separate avoided energy rate for solar QFs. As part of the Companies' continuing focus on evolving towards a more sustainable solar generation model for our customers, I agree that it may be reasonable in the next biennial avoided cost proceeding to consider a small solar-specific QF avoided cost rate design if all avoided costs and potential benefits of incremental solar QF generation on the Companies' systems are taken into account.

This concludes my summary.

MS. FENTRESS: Thank you. Ms. Bowman is available for cross.

MR. BREITSCHWERDT: Mr. Chairman, at this time we'd also introduce Mr. Freeman.

DIRECT EXAMINATION

BY MR. BREITSCHWERDT:

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

A (MR. FREEMAN) Gary Freeman, business address is 410 South Wilmington Street, Raleigh, North Carolina.

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

A Duke Energy and I am the General Manager of Renewable Development Compliance and Origination.

Q Did you cause to be prefiled on February 21st of this year 23 pages of direct testimony and one exhibit?

A Yes, I did.

Q Do you have any changes or corrections to that testimony at this time?

A No.

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

A Yes.

MR. BREITSCHWERDT: Mr. Chairman, at this time I would move that Mr. Freeman's direct testimony be copied into the record as if given orally from the stand and his Exhibit 1 be premarked.

CHAIRMAN FINLEY: Mr. Freeman's direct prefiled testimony filed February 21, 2017, consisting of 23 pages is copied into the record as though given orally from the stand, and his exhibit to his direct testimony is marked as premarked in the filing.

MR. BREITSCHWERDT: Thank you, sir.

Freeman Exhibit 1

(Identified)

(WHEREUPON, the prefiled direct testimony of **GARY FREEMAN** is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

| | | |
|---|---|---|
| In the Matter of | ) | **DIRECT TESTIMONY OF** |
| Biennial Determination of Avoided Cost | ) | **GARY FREEMAN** |
| Rates for Electric Utility Purchases from | ) | **ON BEHALF OF DUKE ENERGY** |
| Qualifying Facilities – 2016 | ) | **CAROLINAS, LLC AND DUKE** |
| | ) | **ENERGY PROGRESS, LLC** |

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

A. My name is Gary Freeman, and my business address is 410 South Wilmington Street, Raleigh, North Carolina.

**Q. WHAT IS YOUR POSITION WITH DUKE ENERGY CORPORATION?**

A. I am the General Manager of Distributed Energy Resources Compliance & Origination for Duke Energy Corporation ("Duke Energy").

**Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND.**

A. I received a Bachelor of Science degree in Mechanical Engineering from Clemson University and a Master of Business Administration degree from UNC-Chapel Hill.

**Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.**

A. I have 37 years of experience in the electric and gas utility industry. In 1999, I joined Progress Energy Corporation, which later merged with Duke Energy. I have worked in various management roles within the Company including overseeing the energy efficiency and demand response programs and supervising the wholesale power trading/generation optimization functions. Before joining what is now Duke Energy in 1999, I spent 19 years with South Carolina Electric and Gas where I held various engineering and management roles in transmission, distribution, customer service, wholesale power trading, and human resources.

**Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?**

A. In my current role, I oversee the power purchasing and distribution interconnection activities for renewable energy resources as well as traditional energy supply resources. I also oversee the development and execution of strategies and compliance plans related to renewable energy for Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") (collectively, the "Companies"), and Duke Energy Ohio, Inc.

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

A. Yes. I most recently provided testimony in Docket No. E-7, Sub 1074 on DEC's 2014 REPS compliance report and application for approval of its REPS cost recovery rider.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to support the Companies' proposals to modify the process by which qualifying facilities ("QFs") obtain a legally enforceable obligation ("LEO"), which has been used in North Carolina to establish the date upon which the QF becomes eligible for DEC's or DEP's avoided cost rates in effect at that time. Specifically, my testimony focuses on the process by which the QF commits to sell its output to the Companies, and explains to the Commission that QFs are (i) not actually making a commitment to sell under the current process at the time a LEO is formed; and (ii) explains how a QF cannot reasonably make a commitment to sell until completing the initial System Impact Study step of the North Carolina interconnection process. After explaining the Companies' rationale for the proposed amendments to the current Notice of Commitment Form ("NoC Form"), as presented in the November 15, 2016, Joint Initial Statement, my testimony then presents the Companies' modified proposal to develop contracting guidelines for non-standard purchase power agreements ("PPAs") that would establish timelines for larger QFs (1 MW and larger) to negotiate PPAs and obtain pricing that better reflects the Companies' current avoided costs at the time the QF actually makes a legally enforceable commitment to sell its output.

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

A. Yes. Freeman Exhibit 1 provides a process overview of the Section 4 full study process under the currently-approved North Carolina Interconnection Procedures ("NCIP").

**Q. PLEASE BRIEFLY DESCRIBE HOW A QF CURRENTLY OBTAINS A LEO IN NORTH CAROLINA.**

A. As discussed in more detail by Witness Kendal C. Bowman, since December 2015, a QF above 2 megawatts ("MW") may establish a LEO in NC by: (1) self-certifying with FERC as a QF; (2) obtaining a Certificate of Public Convenience and Necessity ("CPCN") from the

Commission to construct the generator; and (3) indicating its intent to make a commitment to sell the facility's output to a utility pursuant to the Public Utility Regulatory Policies Act ("PURPA") through the use of the approved NoC Form.

**Q. DO THE COMPANIES BELIEVE THE CURRENT LEO POLICY IS CONSISTENT WITH PURPA'S INTENT?**

A. No. As further described by Witness Bowman, the Companies do not believe the manner in which a LEO is established today is consistent with PURPA's intent that a QF must make a legally enforceable commitment to sell – either through executing a PPA or under a non-contractual LEO where the utility refuses to enter into a contract – in order to obligate the utility and its customers to purchase the QF's output.

**Q. IN THE COMPANIES' EXPERIENCE, ARE QFS ACTUALLY COMMITTING TO SELL THEIR OUTPUT WHEN THEY SUBMIT THE NOC FORM, SUCH THAT THE COMPANIES CAN AVOID OTHER PLANS TO CONSTRUCT NEW GENERATION OR PURCHASE ALTERNATIVE POWER?**

A. No. In the Companies' experience, the NoC Form is submitted very early in the QF development process when the project has not progressed sufficiently for the QF to actually make a legally enforceable commitment to deliver power. Under the current process, the Companies' customers essentially become obligated to purchase from a QF when a CPCN is issued. However, the Companies' experience since the NoC Form was adopted is that a QF project is establishing a LEO and purportedly making a legally enforceable commitment to sell at a time when the QF: (i) has no concrete information on the feasibility, cost, or timing of interconnection; (ii) is not ready, willing, and able to sell power; and (iii) has not even begun PPA negotiations with the utility.

**Q. PLEASE EXPLAIN HOW NORTH CAROLINA'S INTERCONNECTION PROCESS AFFECTS A QF'S ABILITY TO ACTUALLY COMMIT TO SELL ITS OUTPUT TO THE COMPANIES.**

A. The interconnection process is now integral to the QF's ability to commit to sell its output to the utility. In May 2015, the Commission approved revisions to the NCIP designed to improve the process and procedures the utilities apply to manage State-jurisdictional generator interconnection requests, including the surging number of utility-scale solar QF interconnection requests described by Witness Bowman. The current NCIP is unique to North Carolina and was designed to address the State's unique interconnection landscape – a landscape that included processing hundreds of solar generators proposing to interconnect in rural areas of the State to the Companies' distribution systems. The NCIP provides three separate tracks for the utility to study proposed generators: 1) Section 2 expedited review of generators under 20 kW; 2) Section 3 Fast Track review of certified inverter-based generators up to 2 MWs; and 3) Section

4 "Full Study" process for large generators above 2 MW proposing to interconnect to the distribution or transmission systems.

I will first address the NCIP Section 4 Full Study process as the vast majority of proposed PURPA interconnection requests are currently for generators above 2 MW. As background for the Commission, my Exhibit 1 presents a process overview of the revised Section 4 Full Study process, as approved in May 2015. The following changes to the Full Study process are relevant to whether a QF may make a reasonably informed commitment to sell power early in the interconnection process.

Elimination of the Feasibility Study – Traditionally, the first study performed by the utility evaluated the feasibility of a proposed generator at the planned point of interconnection. Due to the stakeholder interest in compressing and expediting the Full Study process to progress towards an interconnection agreement ("IA"), the Feasibility Study was eliminated in the 2015 NCIP revisions and the System Impact Study is now the first study completed. As growing numbers of solar generators are now interconnected and operating in parallel with the rural distribution system, the Companies' recent experience is that certain proposed points of interconnection either may not be feasible to interconnect additional solar without adversely impacting power quality and reliability or the proposed generator must be significantly modified (i.e., a reduction in nameplate generator capacity) during the study process to make the interconnection feasible.

Interdependency-Driven Interconnection Processing – The current NCIP is also unique to North Carolina in that it modifies the traditional "first in, first studied" queuing process. This modification addressed the growing inefficiency associated with the utility studying a generator interconnection request whose interconnection costs and timing are "interdependent" upon the decisions of a lower queued generator that may or may not commit to make increasingly expensive system Upgrades and to proceed to interconnection. Under NCIP Section 1.8, only the first and second interdependent projects (known as Project A and Project B) move forward to the System Impact Study, while subsequent interconnection requests are designated "On Hold" pending Project A and then Project B electing whether to move forward with interconnection or withdraw. For example, Project C does not become a Project B and begin study until Project A has executed its IA and paid for the system Upgrades required to support its interconnection as illustrated in the NCIP, Section 1.8.3.

Interdependency is critically important to the LEO discussion as an "On Hold" project may not even begin the System Impact Study for 12-18 months from its interconnection request date while the utility studies projects ahead of it in queue. Currently, there are over 150 "On Hold" interconnection requests in DEC's and DEP's North Carolina interconnection queues and 33 different substations where far more proposed generators (A, B, C, and D) have submitted an interconnection request for study than can even be accommodated by the substation size, transmission, and/or distribution systems.

The System Impact Study and Interim IA – With elimination of the Feasibility Study, the System Impact Study is now the first step in the study process during which the utility evaluates the impact of interconnecting the proposed generator to the grid and provides the Interconnection Customer with "preliminary non-binding indication of the cost and length of time that would be necessary to provide Interconnection Facilities." Upon completion of the System Impact Study, the NCIP provides that an Interconnection Customer may also request a non-binding "Interim Interconnection Agreement" to assist the QF in pursuing financing for its proposed project. At this stage, neither party is committing to any agreement on the detailed costs of Upgrades or Interconnection Facilities nor on the time required for the interconnection construction to be completed.

The "Dwell Period" Prior to Facilities Study – Another unique aspect of the NCIP is that an Interconnection Customer is allowed 60/180 calendar days (solar/non-solar) to elect whether to proceed to the Facilities Study where the utility would develop detailed construction cost estimates, design drawings, and work orders that would be used in developing the IA. This extensive period of time, informally coined the "dwell period," was intended to allow the QF developer time to determine whether to proceed with the project and to complete development work, including obtaining permitting, evaluating financing opportunities, and negotiating long-term site control, before moving to a detailed Facilities Study and final IA.

<u>Requirement to Pay Upgrades within 60 Calendar Days of IA</u> – Once a final IA is delivered to the Interconnection Customer, the customer has 60 calendar days to pay for required Upgrades to the utility's system to support the interconnection and to pay/provide financial security towards construction of Interconnection Facilities. Recognizing the surging levels of QF projects requesting to interconnect, the NCIP provides that a QF must financially commit to 100% of the Upgrade costs pre-construction to assure projects later in the study queue (and the utility processing the studies) can rely on these Upgrades being constructed.

**Q. IN THE COMPANIES' EXPERIENCE, WHEN ARE QF DEVELOPERS ACTUALLY COMMITTING TO INTERCONNECTION AND CONSTRUCTION OF LARGER SOLAR PROJECTS PROCEEDING THROUGH THE FULL STUDY PROCESS?**

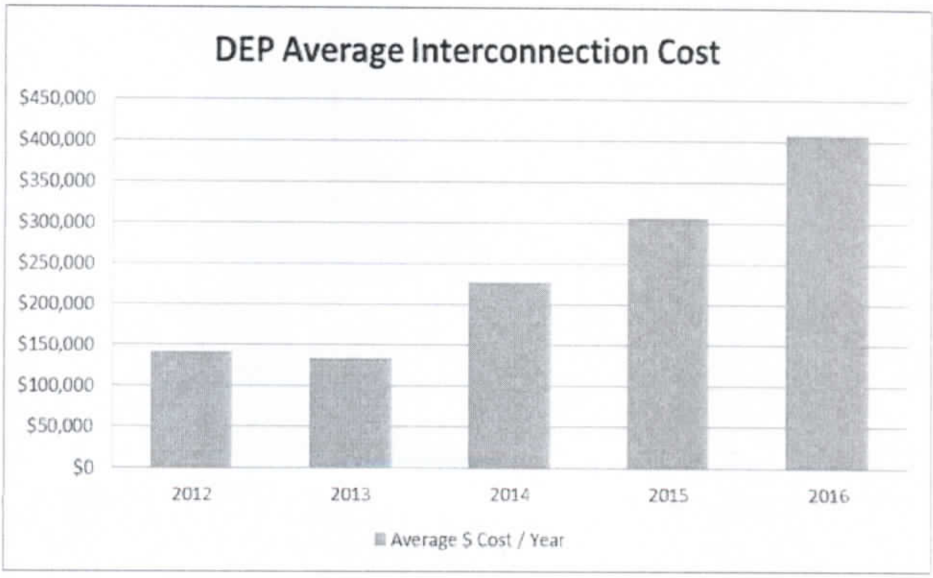
A. Signing the IA establishes a contractual commitment, but even then a QF developer can walk away without any obligation to develop the project. The Companies effectively treat the 60 calendar day period provided in the NCIP for payment of Upgrades as an informal due diligence period where the Interconnection Customer may terminate the IA without liability if it elects not to pay. Thus, the first true commitment to proceed with interconnection is made when the QF pays for the Upgrades, which allows the utility to begin construction work.

As described above, the pre-IA System Impact Study and Facilities Study process is non-binding and intended to allow the Interconnection Customer to continue progressing with development work as the interconnection studies progress. During the study process, a QF Interconnection Customer may withdraw its project without liability and receive a refund of its unused study deposit at any point along the way. Thus, unquestionably, no commitment is being made to complete the project during this period.

Looking back further towards the beginning of the interconnection process, the QF developer cannot reasonably make an informed commitment prior to completion of the System Impact Study process because it has not been informed by the utility on the feasibility of the proposed interconnection or on the cost and length of time necessary to construct Interconnection Facilities and any needed Upgrades. This is even more significant under the May 2015 revised NCIP, as over 150 projects that have submitted Full Study interconnection requests are currently designated "On Hold" and may not even begin the System Impact Study for 12-18 months or longer in some cases.

**Q. PLEASE EXPLAIN HOW THE RECENT INCREASE IN COST AND TIMING OF CONSTRUCTING UPGRADES FURTHER IMPACTS THE BALANCE BETWEEN QFS AND CUSTOMERS UNDER THE EXISTING LEO POLICY.**

A. As noted above, the current Sub 140 LEO standard allows QFs to establish a LEO and receive the benefit of avoided cost rates (albeit, without making any legally enforceable commitment) only a few months into the development process when a CPCN is obtained, while the utilities are having to wait increasing lengths of time after the "LEO date" to actually begin receiving power from the QF. The chart below shows the year-over-year increases in the average costs of Upgrade and interconnection facilities required to interconnect QFs to the Companies' systems.




These cost increases are largely driven by more complex interconnection and Upgrade solutions being required as the "zero Upgrade" interconnection locations have already been taken up by the approximately 1,300 MWs of projects already interconnected to the DEC and DEP distribution systems as of December 31, 2016. Along with the increasing cost, the time to construct these facilities is also increasing. This means that two to four years could pass between a Sub 140 "LEO date" and the point in time that a QF begins delivering power to customers. This extended period heightens the risk and likelihood that the LEO committed rates no longer align with the Companies' then-existing avoided costs, effectively assigning the risk of stale and inaccurate avoided costs to the Companies' customers.

**Q. PLEASE NOW DESCRIBE THE NCIP FAST TRACK PROCESS.**

A. The NCIP Section 3 Fast Track provides for expedited review of certified inverter-based generators up to 2 MWs and applies pre-established technical screens set forth in NCIP § 3.2 to determine whether a generator may be interconnected consistent with safety, reliability, and power quality standards. The Fast Track process is designed to be completed within 15 business days, and an IA is executed if the proposed generator interconnection passes the screens. If screens are failed, the generator may elect a supplemental review to determine whether the generator can be safely interconnected and, if not, the generator must proceed to the Section 4 Full Study process for more detailed System Impact Study review to determine whether the proposed generator can be safely and reliably interconnected.

**Q. WHAT CHANGES DID THE COMPANIES PROPOSE TO THE NOC FORM IN THEIR JOINT INITIAL STATEMENT?**

A. In Exhibit 5 to the Joint Initial Statement, DEC and DEP proposed to revise the NoC Form to require that a LEO cannot be formed until an Interconnection Customer proceeding under the Section 4 Full Study process elects to proceed out of the post-System Impact Study dwell period by executing and returning the Facilities Study agreement. For Fast Track projects or smaller Section 2 certified inverter-based projects less than 20 kW, the Companies included a modification to require a Fast Track-eligible Interconnection Customer to submit a completed Interconnection Request.

**Q. DO THE COMPANIES CONTINUE TO SUPPORT THE PROPOSED MODIFICATIONS TO THE NOC FORM PRESENTED IN THE JOINT INITIAL STATEMENT?**

A. As noted above, the Companies fully support the policy position behind the proposed NoC Form amendments and would support Commission approval of the modified LEO Form set forth in the Joint Initial Statement if the Commission does not elect to transition to the contracting procedures for larger QFs discussed below. The Companies believe that requiring a QF to progress through the System Impact Study process and commit to proceed to a detailed Facilities Study under North Carolina's NCIP should minimally be required as an indicia of viability in order to establish a LEO and obligate the Companies' customers to purchase from a QF.

**Q. ARE THE COMPANIES AWARE OF ANY RECENT FERC DECISIONS ADDRESSING FORMATION OF A LEO THAT ARE POTENTIALLY RELEVANT TO THE PROPOSED NOC FORM MODIFICATION?**

A, Yes. Although I am not an attorney, in my current role, I have become aware of two recent FERC decisions issued after the Companies filed their Joint Initial Statement at the Commission on November 15, 2016, that address whether requirements imposed by States on QFs to establish a LEO are consistent with PURPA. The first is a December 15, 2016, decision on a petition for enforcement by FLS Energy, LLC ("FLS") against the Montana Public Service Commission on behalf of 14 of FLS' solar QF LLCs seeking to obtain NorthWestern Energy's ("NorthWestern") standard avoided cost tariff offer.[1] On June 16, 2016, the Montana Commission had approved an emergency petition by NorthWestern to suspend its standard QF-1 tariff offer to QFs greater than 100 kW based upon NorthWestern's representation that its customers would be entering into additional standard QF PPAs at stale avoided cost rates, imposing significant excess costs on them.[2] The Montana Commission relied upon its previously established LEO standard, which

[1] *FLS Energy, Inc.*, 157 FERC ¶ 61,211 (2016) ("FLS Order").
[2] *In the Matter of Northwestern Energy's Application for Interim and Final Approval of Revised Tariff No. QF-1, Qualifying Facility Power Purchase, Order on NorthWestern Energy's Motion for Emergency Suspension of Tariff Schedule QF-1*, Montana Public Service Commission Docket No. D2016.5.39; Order No. 7500 (June 16, 2016).

required a QF to have partially executed a PPA with the utility as well as executed an IA, as determinative of whether a QF would be eligible for the suspended rate schedule. FLS alleged that it had tendered PPAs committing to sell to NorthWestern prior to the suspension order, but had not yet received executable IAs. FLS also alleged that it was entitled to receive executable IAs for 6 of the 14 QFs, but that NorthWestern had violated its Open Access Transmission Tariff by exceeding the time allowed by the tariff to provide the IAs.[3]

While FERC elected not to bring an enforcement action against the Montana Commission, it did express its view that specifically requiring an executed IA as part of a State's LEO standard is inconsistent with its PURPA regulations because "[s]uch a requirement allows the utility to control whether and when a legally enforceable obligation exists – e.g., by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable interconnection agreement."[4] FERC reiterated that the LEO concept is intended to prevent a utility from circumventing the requirement to provide a capacity credit "merely by refusing to enter into a contract with the [QF]" because "the establishment of a legally enforceable obligation turns on the QF's commitment, and *not* on the utility's actions."[5]

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[3] *FLS Order* at P. 4.
[4] *FLS Order* at P. 23.
[5] *FLS Order* at P. 24. (emphasis in original).

In the second decision, a New Mexico QF petitioned FERC for enforcement, alleging that the New Mexico Public Service Commission's regulation requiring a QF to be already constructed and physically interconnected to the utility's system to establish a LEO was inconsistent with PURPA.[6] On January 6, 2017, FERC issued a notice of intent not to act, in response to the New Mexico QF's petition, in which FERC provided no guidance that New Mexico's LEO standard was inconsistent with PURPA nor took any action.

Taken together, these recent orders show that states continue to have broad discretion to determine the level of commitment a QF is required to make in order to establish a LEO, but that any clearly defined LEO standard should focus on the QF's commitment and not be overly beholden to a specific action by the utility. In the *FLS Order*, the FLS QFs had already delivered executed PPAs to NorthWestern in support of their legally enforceable commitment to sell. In the New Mexico enforcement action, FERC did not find that obligating a QF to complete construction of the generator and to proceed to the point of physical interconnection prior to establishing a LEO was inconsistent with its regulations.

The additions to the North Carolina NoC Form presented in the Companies' Joint Initial Statement are generally consistent with both of

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[6] *See Waste Water and Power Production Limited*, LLC, 158 FERC ¶ 61,015 (2017) (Issuing notice of intent not to act in response to petition for FERC enforcement); *see also Waste Water and Power Production Limited, LLC, v. Public Service Company of New Mexico*, Case No. 11-00466-UT (Aug. 3, 2016).

these Orders. The Companies designed the new NoC Form language to allow the QF to provide some indicia of commitment by executing the Facilities Study agreement after reviewing its System Impact Study results. During the dwell period, which is unique to the NCIP, the QF has the unfettered right to proceed to a detailed Facilities Study or withdraw. Further, while the Companies must complete the System Impact Study under the NCIP prior to the "dwell period," the Companies' experience does not support that it is even feasible for a QF to make a commitment to provide energy and capacity to the utility over a specified future term prior to completing the System Impact Study. Finally, recognizing that numerous QF interconnection Customers are interdependent and do not begin the System Impact Study immediately, it is increasingly unjust and unreasonable to continue to obligate the Companies' customers to pay avoided costs – effectively assigning the risk of future non-performance to the utility and its customers – at this early stage of the development process.

As I discuss further below related to the Companies' proposed contracting procedures, if a QF believes it is sufficiently viable prior to completing the System Impact Study and is ready, willing, and able to make a legally enforceable commitment to sell, then it is within its rights to execute a PPA with the utility and actually commit itself to deliver power.

**Q. ARE THE COMPANIES ALSO PRESENTING A MODIFIED PROPOSAL TO THE COMMISSION AT THIS TIME?**

A. Yes. During the past few years, other jurisdictions with significant PURPA activity have transitioned to formalized contracting procedures between larger QFs and utilities, which more appropriately align the establishment of a legally enforceable commitment to sell with the date upon which a QF actually agrees in a PPA to commit itself and becomes obligated to deliver power over a specified term. If implemented in North Carolina, this process could resolve the Companies' concerns about the growing harm to customers of stale avoided cost rates, while also providing QFs certainty as to the process for negotiating a definitive PPA.

For example, the Oregon Public Utilities Commission ("PUC") initially mandated standardized QF contracting procedures and negotiating guidelines back in 2007.[7] In May 2016, the Oregon Commission modified its prior LEO determination standard to reflect that "there is no LEO until a utility and a QF have undertaken the contracting process, and negotiations have progressed beyond initial contact by a QF." The PUC adopted its Staff's proposal that "a LEO exist[s] when a QF signs a final draft of an executable standard contract that includes a scheduled commercial on-line date and information regarding the QF's minimum and maximum annual deliveries, thereby obligating itself to provide power

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[7] *In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Order No. 07-360 at 42-43; Docket No. UM 1129 (Aug. 20, 2007).

or be subject to penalty for failing to deliver energy on the scheduled commercial on-line date."[8]

Similarly, in 2014, the Idaho Public Utilities Commission approved standardized contracting procedures for Avista Corporation's and Idaho Power Company's ("IPC") respective cogeneration and small power production tariffs that would create more process certainty between the utilities and QFs in the PPA negotiation process. In approving Avista's proposed contracting procedures in its tariff, the Idaho Commission explained:

> The intent of creating rules and timelines to guide the negotiations process … is to create more certainty for both parties, to ensure that both parties are bargaining in good faith, and to prevent avoided cost rates from becoming stale. … Stale rates are not an accurate reflection of the utility's true avoided costs.[9]

**Q. IF REASONABLE CONTRACTING PROCEDURES ARE IMPLEMENTED, WOULD THE COMPANIES STILL HAVE CONCERNS ABOUT QF DEVELOPERS MAKING A COMMITMENT TO SELL PRIOR TO COMPLETING THE SYSTEM IMPACT STUDY?**

A. Yes. For the reasons discussed above, the Companies believe it is reasonable to require a QF to complete the System Impact Study and commit to a Facilities Study prior to making a commitment to sell.

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[8] *In the Matter of Public Utility Commission of Oregon Staff's Investigation into Qualifying Facility Contracting and Pricing*, Order No. 16-174 at 27; Docket No. UM 1610 (May 13, 2016).
[9] *In the Matter of the Application of Avista Corporation for Approval of Proposed Revisions to Schedule 62*, Order No. 33048 at 5-6, Idaho Public Utilities Commission Case No. AVU-E-14-03 (May 30, 2014).

However, the more fundamental issue for the Commission to consider is that the QF developer and not the Companies' customers should be taking on the risk of the QF's non-performance at the time the QF's "commitment to sell" is made. As I mentioned above, the QF should have a right to make a legally enforceable commitment to sell by executing a PPA with the utility and actually commit itself to deliver power. Customers should be protected from the risk of the QF's potential non-performance by including reasonable and appropriate liquidated damages (if the QF is late in achieving commercial operation) or termination damages (if the QF elects not to perform).[10]

**Q. HOW DO THE COMPANIES PROPOSE THE COMMISSION IMPLEMENT THIS MODIFIED PROPOSAL TO ESTABLISH CONTRACTING PROCEDURES?**

A. The Companies recommend a streamlined LEO form be adopted for small QFs 1 MW or less that are eligible for the standardized avoided cost rates and terms and conditions. This streamlined form would consist of: (1) submission of a Report of Proposed Construction to the Commission under Rule R8-65; (2) submission of a Section 2 or Section 3

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[10] *In the Matter of the Application of Idaho Power Company for Approval and Implementation of Schedule 73, Cogeneration and Small Power Production*, Order No. 33197 at 5 Idaho Public Utilities Commission Case No. IPC-E-14-24 (Dec. 29, 2014) (explaining "[A] responsible developer will be sufficiently through the interconnection process to be able to achieve the on-line date stated in its energy sales agreement. We find that including a requirement that interconnection studies be complete unnecessarily complicates what is intended to be a tariff governing the negotiation of energy sales agreements. To the extent that a developer acts hastily in attempting to get a project on-line and fails to complete the interconnection process, the developer is held accountable through liquidated and/or termination damages pursuant to the terms of the energy sales agreement.").

Interconnection Request, which the Company deems complete; and (3) indication of intent (i.e., a notice of commitment) to sell the QFs output to DEC or DEP under then-approved standard avoided cost rates and subject to the requirements specified in the tariff, including current time limits to begin delivery of power from the facility.

For larger non-standard offer projects above 1 MW, the Companies propose to work with the Public Staff and other interested parties to develop publicly available procedures for the negotiation of a non-standard PPA at a QF's request. Key components of these procedures would include:

- QFs would have the right to commence negotiations by submitting project specific information and characteristics and requesting non-binding indicative pricing and a draft PPA;
- The Companies would deliver current indicative pricing and a draft PPA to the QF within 30 calendar days;
- The indicative pricing would remain available for a period of 60 calendar days from the delivery date of the indicative pricing before becoming stale, thereby triggering a requirement that the QF request new indicative pricing;
- The QF and the utility would negotiate in good faith towards finalizing a PPA. When both parties are in full agreement on all terms and conditions of the power purchase agreement, the Company will prepare and forward to the QF owner a final,

executable version of the agreement, which would be executed by the QF and returned to Company within 15 calendar days. The avoided cost rates to be paid to the QF would become firm rates once the QF signs the final draft executable PPA that includes a scheduled commercial on-line date and information regarding the QF's minimum and maximum annual deliveries, thereby obligating itself to provide power or be subject to penalty for failing to deliver energy on the scheduled commercial on-line date. This would essentially follow the current approach in Oregon and Idaho.

- The PPA would also include a 60 calendar day "post-execution due diligence period," providing the QF reasonable additional time to ensure it is prepared to make a legally enforceable commitment to sell power over the term specified in the PPA.

To the extent the parties cannot agree on a material term during the PPA negotiations, a dispute resolution process similar to Section 6.2 of the NCIP could be established to informally resolve any issues of disagreement. Similar to the current process, a QF could also file a complaint or petition for arbitration with the Commission.

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

A. Yes.

BY MR. BREITSCHWERDT:

Q Mr. Freeman, did you also cause to be prefiled in this docket on April 10, 17 pages of rebuttal testimony and two exhibits?

A (MR. FREEMAN) Yes, I did.

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

A No.

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

A Yes.

MR. BREITSCHWERDT: Mr. Chairman, at this time I would also move that Mr. Freeman's rebuttal testimony be copied into the record and that his two rebuttal exhibits be premarked as identified in his rebuttal testimony.

CHAIRMAN FINLEY: Mr. Freeman's rebuttal testimony filed April 10, 2017, consisting of 17 pages is copied into the record as though given orally from the stand, and his two exhibits are marked for identification as premarked in the filing.

MR. BREITSCHWERDT: Thank you, sir.

Freeman Rebuttal Exhibits 1 and 2

(Identified)

(WHEREUPON, the prefiled rebuttal testimony of **GARY FREEMAN** is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 148

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| In the Matter of<br>Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016 | )<br>)<br>)<br>)<br>) | REBUTTAL TESTIMONY OF GARY FREEMAN ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC |

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

A. My name is Gary Freeman, and my business address is 410 South Wilmington Street, Raleigh, North Carolina.

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

A. I am the General Manager of Distributed Energy Resources Compliance & Origination for Duke Energy Corporation ("Duke Energy").

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

A. Yes. I pre-filed direct testimony in this proceeding on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies") on February 21, 2017.

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

A. The purpose of my rebuttal testimony is to address certain positions and arguments presented in the testimony of the North Carolina Utilities Commission – Public Staff ("Public Staff") Witnesses Jay B. Lucas and John R. Hinton; North Carolina Sustainable Energy Association ("NCSEA") Witness Carson Harkrader; and Southern Alliance for Clean Energy ("SACE") Witness Thomas Vitolo. Specifically, my rebuttal testimony rebuts the Public Staff's and NCSEA's alternative proposals for the North Carolina Utilities Commission ("Commission") to administratively establish a standard for a qualifying facility ("QF") to make a legally enforceable commitment to sell ("LEO"), as well as provides the Commission further detail regarding the

Companies' proposed contracting procedures as introduced in my pre-filed direct testimony. I also respond to SACE Witness Vitolo's speculative argument that reducing the Companies' standard offer eligibility to one megawatt ("MW") will unreasonably increase the number of projects proceeding through the Companies' interconnection queues.

**Q. ARE YOU INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?**

A. Yes. Freeman Rebuttal Exhibit 1 provides the Commission a revised streamlined Notice of Commitment Form ("NoC Form") for small QFs 1 MW or less eligible for DEC's and DEP's standard Schedule PP avoided cost tariffs. Freeman Rebuttal Exhibit 2 provides the Commission the Companies' proposed Notice of Intent to Negotiate Power Purchase Agreement form and contracting procedures under which large QFs above 1 MW would negotiate a power purchase agreement ("PPA") with the Companies, as introduced in my pre-filed direct testimony.

**Q. PLEASE BRIEFLY SUMMARIZE YOUR DIRECT TESTIMONY.**

A. My testimony addresses the Companies' recent experience since the Commission-approved NoC Form was adopted in 2015 that a QF project is establishing a LEO and purportedly making a legally enforceable commitment to sell at a time when the QF: (i) has no concrete information on the feasibility, cost, or timing of interconnection; (ii) is not ready, willing, and able to sell power; and (iii) has not even begun negotiations of a PPA with the utility. I emphasize the heightened importance of fixing North Carolina's

LEO policy in light of the Companies' proposal to reduce standard offer eligibility to 1 MW, and then introduce the Companies' modified proposal that larger QFs above 1 MW should make a legally enforceable commitment to sell by negotiating a PPA with the utility under Commission-approved contracting procedures.

**Q. DOES PUBLIC STAFF WITNESS LUCAS APPROPRIATELY CHARACTERIZE THE COMPANIES' CONCERNS WITH THE CURRENT NoC FORM PROCESS FOR A QF TO ESTABLISH A LEGALLY ENFORCEABLE COMMITMENT TO SELL POWER?**

A. Yes, he does. At pages 4-5 of his testimony, Witness Lucas recognizes the following key points presented in my direct testimony and in the testimony of Witness Kendal C. Bowman:

- **The LEO policy.** Under the Public Utility Regulatory Policies Act ("PURPA"), the purpose of a "QF's commitment through a LEO to sell its power to the utility should allow the utility to avoid other plans to construct new generation or purchase alternative power."
- **The current reality.** "In reality, the utility cannot avoid plans to construct future generation" based upon the current administratively-established LEO policy because "the current criteria do not commit the QF to build a generator at all."
- **Currently the "LEO risk" is assigned to customers.** "[C]ustomers bear the risk of providing a LEO to a QF that may not be able to meet its power delivery date" or may elect not to build the generator at all.

- **Customers are being obligated to pay "stale rates" when a LEO is established early in the interconnection process.** Where a QF has administratively established a LEO, "delays [in the interconnection process], as well as the time to construct a project, cause the actual power delivery date to lag as much as two to four years after the date of the establishment of the LEO. This late delivery of power forces Duke's customers to pay an avoided cost rate to the QF that may no longer be reflective of Duke's current avoided costs."

**Q. DOES THE PUBLIC STAFF DISAGREE WITH THESE CONCERNS?**

A. Not directly. The Public Staff does not specifically respond to the Companies' position that the purpose of a LEO under PURPA is to allow a QF to make a legally enforceable commitment to sell – either through executing a PPA or under a non-contractual LEO should the utility refuse to enter into a contract – in order to obligate the utility and its customers to purchase the QF's output.

However, the Public Staff does recognize that a QF cannot make a reasonable and informed commitment to sell its power prior to completing the System Impact Study. On page 9 of his testimony, Witness Lucas explains that "[u]pon receiving the System Impact Study results, a QF owner should have information on the feasibility, costs, and time required for its proposed interconnection, and therefore, be in a better position to evaluate the viability of the project and commit to building the facility than at the beginning of the interconnection process." Also on page 9, Mr. Lucas recognizes that prior to moving through the interconnection study process, "the project owner has little or no information regarding whether it is technically or economically feasible to interconnect at its requested point of interconnection."

**Q. DOES THE PUBLIC STAFF AGREE WITH THE COMPANIES' PROPOSAL TO EVOLVE THE CURRENT LEO POLICY BY ACTUALLY REQUIRING LARGE QFs TO MAKE A LEGALLY ENFORCEABLE COMMITMENT TO SELL?**

A. No, they do not. While the Public Staff's proposal recognizes the need to evolve the LEO policy and current NoC Form in some respects by requiring a QF to become a Project A or Project B under Section 1.8 of the North Carolina Interconnection Procedures ("NCIP") and to at least ***begin*** System Impact Study, this does not make the QF's "commitment" through submittal of the NoC Form any more meaningful. The Public Staff does not seem to agree that a QF should actually be required to make a binding commitment (i.e., take on the risk of non-delivery of power) in order to obligate the Companies' customers to buy the QF's power under PURPA.

**Q. HOW DOES NCSEA WITNESS HARKRADER DISCUSS THE QF'S COMMITMENT THAT SHOULD SATISFY THE LEO STANDARD?**

A. At page 20, Witness Harkrader extensively discusses commitments made by a QF developer in the "early stages" of the QF development process including securing site control, obtaining regulatory approvals, and submitting an interconnection request. She concludes that "significant commitments – in terms of expenditure of time and financial resources and the securing of necessary approvals – are made toward the development of the QF before the interconnection study process is completed."

**Q. ARE THESE COMMITMENTS IMPORTANT TO WHETHER A QF HAS MADE A LEGALLY ENFORCEABLE COMMITMENT TO SELL?**

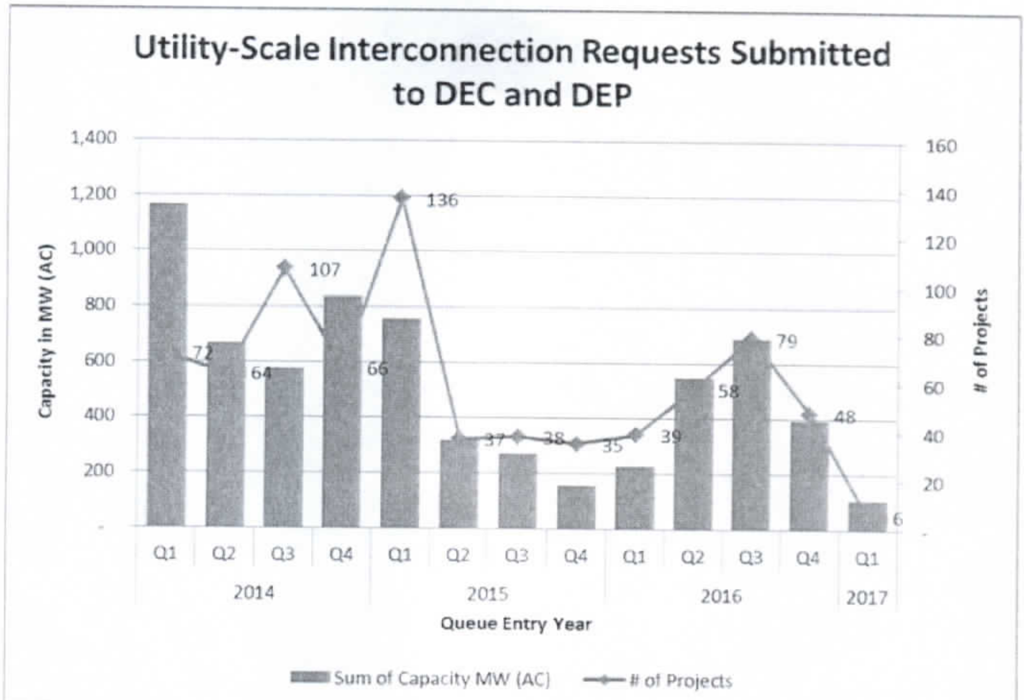
A. I don't dispute Ms. Harkrader's statements that early stage development of a QF includes making commitments of time and financial resources. However, these are not the commitments contemplated by the Federal Energy Regulatory Commission's ("FERC") regulations that provide that a QF can obligate the utility and its customers to purchase its power. A legally enforceable commitment to sell power requires a QF to commit itself to "provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term." 18 C.F.R. 292.304(d). Only where a QF commits itself to deliver power over a specified term should a LEO arise.

**Q. PLEASE RESPOND TO THE PUBLIC STAFF'S AND NCSEA'S PROPOSAL TO ADMINISTRATIVELY GRANT A QF A LEO 105 DAYS AFTER SUBMITTING A COMPLETE INTERCONNECTION REQUEST.**

A. I disagree with this proposal because it does not require the QF to make a meaningful commitment to sell and would allow a QF to submit a "notice of commitment," thereby obligating the utility and customers, prior to receipt of interconnection study information that is needed to determine whether it is technically or economically feasible to interconnect at the QF's proposed point of interconnection. This essentially continues the current policy of providing a QF the right or option to sell at avoided cost, but creates no obligation that the QF will deliver power to the Companies.

Also, I do not read the 105-day requirement as being applicable to "On Hold" projects that will not begin study under NCIP Section 1.8 until the QF interconnection customer becomes a Project A or Project B. I addressed this interdependency concept extensively in my direct testimony, but would reiterate for the Commission that there are currently over 150 "On Hold" interconnection requests (not Project As or Bs) in DEC's and DEP's North Carolina interconnection queues and 33 different substations where far more proposed generators (A, B, C, and D) have submitted an interconnection request for study than can even be accommodated by the substation size, transmission, and/or distribution systems. This means that many new QF interconnection customers will be interdependent and not eligible to begin a System Impact Study 105 days after their interconnection request is deemed complete.

I would also like to respond to the implicit suggestion underlying this proposal that the delays in the interconnection study process have been within the utility's control. DEC and DEP have worked in good faith with the solar community, other QF developers, and our retail customers interested in installing distributed energy resources to study all interconnection requests in a non-discriminatory manner and have made reasonable efforts to meet the timeframes in the NCIP. However, as highlighted in the chart below, approximately 785 new utility-scale interconnection requests above 1 MW have been submitted since January 1, 2014 to interconnect more than 6,700 MWs of new generation to the Companies' systems. Of these projects, 28% have either withdrawn from the interconnection process or canceled their project. This suggests the speculative nature of establishing a LEO proximate to submitting the interconnection request, which occurs early in the QF development process.




To my knowledge, the level of utility-scale solar development on the DEP distribution system specifically is unprecedented across the country. I do not dispute that the interconnection study process is – as it should be – ultimately within the Companies' control in order to ensure all requests to interconnect new generators to the distribution and transmission systems are studied in a non-discriminatory manner that assures long-term system safety, reliability of service, and power quality for all customers. However, in my view, the primary cause of the Companies not meeting the NCIP's study timelines is not a dereliction of responsibility, but is primarily attributable to the continuing surge in new interconnection requests and the growing complexity of the distribution study process as multiple utility-scale generators propose to interconnect on the same circuit. As highlighted in the Companies' Joint Initial Statement, I look forward to continuing to work with other stakeholders to improve the North Carolina interconnection process when the E-100, Sub 101 stakeholder process recommences in May of this year.

**Q. BOTH PUBLIC STAFF WITNESS LUCAS AND NCSEA WITNESS HARKRADER ALSO POINT TO FERC's RECENT *FLS ENERGY* ("FLS") ORDER AS SUPPORTING THEIR POSITION. DO YOU AGREE?**

A. No, I do not. I extensively addressed this recent FERC decision in my direct testimony and will not do so again here. However, I would like to emphasize one key fact from that case for the Commission's consideration. In Paragraph 4, FERC highlights that all 14 FLS QFs had reached an agreement with the utility on all material terms of the PPA to sell their power and had tendered signed PPAs back to the utility on the date FLS asserted they had made a legally enforceable commitment to sell.[1] This is completely consistent

[1] *FLS Energy, Inc.*, 157 FERC ¶ 61,211 (2016) ("FLS Order").

with the Companies' position and proposed contracting procedures, as discussed below. Where a QF negotiates and executes a PPA to sell its power to the utility, it seems completely reasonable that a subsequent administrative delay by the utility in delivering an interconnection agreement should not preclude a legally enforceable commitment to sell under the PPA from being established.

**Q. PLEASE SUMMARIZE THE COMPANIES' CONCERNS WITH THE PUBLIC STAFF'S AND NCSEA'S LEO POLICY PROPOSAL FOR LARGER QFs.**

A. The Companies' core disagreement with Public Staff's and NCSEA's proposals is that QFs should not continue to be allowed to establish a LEO without actually making a binding commitment to sell. Getting this policy right is very important, as the Companies are proposing to transition utility-scale QFs between 1 MW and 5 MWs to non-standard negotiated avoided cost rates, which are updated monthly versus only every two years under the standard tariff. It is also now significantly more important to ensure that larger QFs make a meaningful and binding commitment to sell through negotiation of a PPA, as the current NoC Form process allows QFs up to 80 MWs in size (a $150+ million dollar capital investment) to establish a LEO without making any actual commitment to sell power. For these reasons, the Companies have recommended developing contracting procedures for larger QFs where the QF can make a binding commitment to sell power over a specified term by signing a PPA.

**Q. BEFORE ADDRESSING THE COMPANIES' PROPOSAL TO ADOPT CONTRACTING PROCEDURES FOR LARGE QFs, CAN YOU PLEASE BRIEFLY ADDRESS THE COMPANIES' LEO PROPOSAL FOR STANDARD OFFER QFs 1 MW AND UNDER?**

A. The Companies have proposed continuing to use a streamlined NoC Form for small standard offer QFs less than 1 MW as an administratively-efficient approach to allowing these small QFs to become eligible for DEC's and DEP's standard Schedule PP avoided cost tariffs. As noted above, this approach is reasonable and appropriate for these smaller QFs because the Schedule PP rates, terms, and conditions are fixed for a two-year period. The Companies have proposed to modify the NoC Form for these small QFs to consist of: (1) submission of a Report of Proposed Construction to the Commission under Rule R8-65; (2) submission of a Section 2 or Section 3 Interconnection Request, which the Company deems complete; and (3) indication of intent (i.e., a notice of commitment) to sell the QF's output to DEC or DEP under then-approved standard avoided cost rates and subject to the requirements specified in the tariff, including current time limits to begin delivery of power from the facility within 30 months of Commission approval of the standard offer avoided cost rates.

**Q. DOES THE PUBLIC STAFF AGREE WITH THE COMPANIES' PROPOSAL FOR A STREAMLINED NoC FORM FOR SMALL QFs?**

A. Yes. Witness Lucas supports the Companies' proposal on page 7 of his testimony.

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**Q. HAVE THE COMPANIES DEVELOPED A STREAMLINED NoC FORM FOR SMALL QFs?**

A. Yes. Freeman Rebuttal Exhibit 1 revises the existing NoC Form for small QFs to reflect the three requirements identified above.

**Q. DOES THE PUBLIC STAFF ALSO SUPPORT THE COMPANIES' PROPOSAL TO ADOPT CONTRACTING PROCEDURES FOR LARGE QFs?**

A. Yes. In his testimony, Public Staff Witness Hinton agreed with the Companies' proposal to develop contracting procedures that improve the efficiency of the negotiated PPA process and specifically recommended the Companies provide additional information regarding this proposal.

**Q. HAVE THE COMPANIES DEVELOPED PROPOSED LARGE QF CONTRACTING PROCEDURES FOR THE COMMISSION'S REVIEW?**

A. Yes. Freeman Rebuttal Exhibit 2 revises the existing NoC Form as a "notice of intent to negotiate a PPA" form. Section four of this form presents procedures for negotiating a PPA. The Companies recommend that the Commission direct the Companies to take input from the Public Staff, DNCP, and other interested parties and to submit any refinements to the proposed contracting procedures as a post-hearing filing.

**Q. DO YOU HAVE ANY SPECIFIC COMMENTS REGARDING THE COMPANIES' CONTRACTING PROCEDURES FOR LARGE QFs?**

A. Yes. The Companies' proposed contracting procedures are commercially reasonable and will improve the transparency and efficiency of the negotiated PPA process by establishing clear milestones and a process for good faith negotiations between the QF and utility. Further, these procedures modify the process for a large QF to make a legally enforceable commitment to sell by focusing on the QF's commitment to enter into a PPA as establishing its obligation to deliver energy or capacity over a specified term, as contemplated by the LEO standard. The decision to make such a commitment is completely within the QF's control, and only where the QF and the utility cannot agree on the terms and conditions of the PPA would the Commission need to get involved to determine whether a non-contractual LEO has been established.

It is also significant that the contracting procedures ensure that customers will not be obligated to purchase from a QF until the QF makes a commitment to sell by entering into a PPA. Prior to the QF making such a commitment, the utility will provide non-binding indicative avoided cost pricing that may be used by the QF developer to make determinations regarding project planning, financing, and feasibility of the proposed QF project. This approach mitigates the risk of stale avoided cost rates as the QF will be provided indicative pricing information needed to evaluate developing the QF, but will not "lock in" avoided cost rates until it actually makes a commitment to deliver power to the utility over a specified term by executing a PPA. While not expressly addressed in the contracting procedures, the Companies' PPA would also include a 60 calendar day "post-execution due diligence period," providing the QF reasonable additional time to ensure it is prepared to make a legally enforceable commitment to sell power over the term specified in the PPA. After this 60-day due diligence period, customers should be protected from the risk of the QF's potential non-performance by including commercially reasonable liquidated damages (if the QF is late in achieving commercial operation) or termination damages (if the QF elects not to perform).

**Q. DO THE COMPANIES HAVE A POSITION ON THE PUBLIC STAFF'S PROPOSAL THAT A QF THAT WITHDRAWS ITS NoC FORM BE PROHIBITED FROM ESTABLISHING A NEW LEO FOR TWO YEARS FROM THE DATE OF WITHDRAWAL AND BE LIMITED TO ESTABLISHING "AS AVAILABLE" ENERGY RATES DURING THAT TIME?**

A. On page 14, Witness Lucas explains the Public Staff's concern that should avoided cost rates begin to increase,

> [A] QF may wish to delay its establishment of a LEO, or even allow a previously executed Notice of Commitment to expire in order to establish a new LEO at the higher rates. In this case, a change in the LEO date could result in customers losing the benefit of the lower rates to which the QF had previously committed, and even potentially allow gaming of rates by a QF at customer expense.

The Companies recognize and agree with the Public Staff's concerns underlying this recommendation, and recommend this proposal be approved for small standard offer QFs subject to the Companies' proposed streamlined NoC Form. I would also highlight that requiring a large QF to execute a PPA and actually commit to deliver power is complementary to the Public Staff's proposal, as the PPA can include similar language if the QF fails to meet its obligations and terminates the PPA prior to commencing delivery of power.

**Q. PLEASE ALSO RESPOND TO SACE WITNESS VITOLO'S ASSERTION THAT REDUCING THE STANDARD OFFER ELIGIBILITY TO 1 MW WILL RESULT IN A SIGNIFICANT INCREASE IN THE NUMBER OF INTERCONNECTION STUDIES THE UTILITY MUST PERFORM.**

A. Witness Vitolo asserts at page 10 that "[o]ne potential outcome of reducing QF eligibility for a standard offer contract from 5 MW generation capacity to 1 MW is a dramatic increase in the number of projects under development" and suggests that this would "induce a significant increase in the number of interconnection studies the utility must perform." First, the argument that reducing the 5 MW standard offer to 1 MW will result in five times the number of projects under development is speculative at best. Second, I emphasize for the Commission that small QF projects eligible for the proposed 1 MW standard offer are also more likely to be eligible for and pass the NCIP Section 3 Fast Track screens, which provides a significantly more streamlined interconnection study process. As recognized by Public Staff Witness Hinton on pages 43-44 of his testimony, the likelihood that QF projects 1 MW or less will pass the NCIP Section 3 Fast Track process represents a "practical reason[s] for supporting a reduction in size to one MW."

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

A. Yes, it does.

BY MR. BREITSCHWERDT:

Q Mr. Freeman, do you have a summary of your direct and rebuttal testimonies to present to the Commission at this time?

A Yes, I do.

Q Would you please do so?

A Thank you, Mr. Chairman, fellow Commissioners.

(WHEREUPON, the summary of **GARY FREEMAN** is copied into the record.)

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
Summary of Gary Freeman's Direct and Rebuttal Testimony
NCUC Docket No. E-100, Sub 148

My Direct Testimony supports the Companies' proposals to improve the process by which qualifying facilities ("QFs") establish a "Legally Enforceable Obligation" or "LEO" in North Carolina, which in turn establishes the point in time at which a QF becomes eligible for the utility's forecasted avoided cost rates. I explain the Companies' recent experience with the Notice of Commitment Form ("NoC Form") process adopted by the Commission in the 2014 Sub 140 proceeding, specifically, that QFs are routinely submitting the NoC Form immediately after receiving a certificate of public convenience and necessity from the Commission. While the NoC Form has been administratively efficient in setting a clear "LEO date," it has resulted in solar developers purporting to make a commitment to sell power to the utility very early in the interconnection and project development process, before the QF has concrete information on the feasibility, cost or timing of interconnection and before Power Purchase Agreement ("PPA") negotiations have begun.

My Direct Testimony also describes the current North Carolina Interconnection Procedures approved by the Commission in May 2015, and explains that the first true commitment by a QF to proceed with interconnection is made when the QF executes the interconnection agreement and pays for system upgrades necessary to support interconnection. Under the existing LEO policy, a QF may assert that it is making a commitment to sell much earlier in the interconnection process – even prior to completing the initial System Impact Study – and before receiving any information from the utility on the cost, timing, and feasibility of interconnecting the proposed generator at the requested point of interconnection. After making this alleged "commitment to sell," the Companies' experience is that the QF developer has not obligated itself and may walk away if it elects not to develop (or cannot sell) the project, which effectively places the risk of the QF's non-performance on the Companies' customers. Due to the significant amount of solar development in North Carolina and the growing number of interdependent or "On Hold" projects in the Companies' interconnection queues, I explain how

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two to four years may pass between a "LEO date" and the date that the QF begins delivering power. This heightens the likelihood that the LEO-committed rates become stale and inaccurate, no longer aligning with the Companies' avoided costs at the time power is delivered.

Through my direct and rebuttal testimonies, the Companies recommend adoption of a streamlined NoC Form for small QFs that are 1 MW or less that are eligible for standardized avoided cost rates and contracts. These small projects can be more efficiently studied through the Section 3 Fast Track interconnection process. Public Staff Witness Jay Lucas supports this recommendation, and I have proposed a streamlined LEO form as Exhibit 1 to my rebuttal testimony for the Commission's and the Public Staff's consideration.

For larger "utility-scale" QFs above 1 MW, my direct and rebuttal testimonies emphasize the importance of requiring the QF to make real and meaningful commitment to sell its power to the utility at a specified future date in order to obligate the utility's customers to purchase that power. Through the proposed contracting procedures presented as Exhibit 2 to my rebuttal testimony, the Companies are proposing a clear and transparent process for a QF to negotiate a PPA and obligate itself to deliver power. Executing a PPA presents the clearest process for a QF to commit itself to deliver power in the future and if a QF believes it is sufficiently viable prior to completing the System Impact Study to make a legally enforceable commitment to sell, then it is within its rights to execute a PPA with the utility and actually commit itself to deliver power. However, the risk of non-delivery should be on the QF developer and not on customers. To enable the QF to make financing and feasibility determinations, the Companies' proposed contracting procedures provide for non-binding indicative avoided cost pricing during negotiations, while the avoided cost rate will become locked in when the QF signs the PPA.

My rebuttal testimony also addresses the alternative LEO proposals offered by Public Staff Witness Lucas and NCSEA Witness Carson Harkrader. The Public Staff proposes that the NoC Form should be updated to require a QF to be a Project A or Project B for purposes of the interconnection study process and that the LEO should not arise until at least 105 days after submitting a complete interconnection request. This administratively established LEO standard would still allow a QF to lock in rates prior to receipt of the interconnection study information that is needed to determine whether it is technically and economically feasible to interconnect at the QF's proposed point of interconnection.

The Companies appreciate the Public Staff's concerns about the ongoing challenges of efficiently studying hundreds of utility-scale solar QFs proposing to interconnect to the Companies' distribution systems. To address this concern, I explain how the "Notice of Intent to Negotiate" Form presented in Exhibit 2 of my rebuttal testimony allows a QF to commence negotiations of a PPA once it becomes a Project A or Project B, which is similar to the Public Staff's proposal. However, the critical difference between the Companies' contracting procedures approach and the Public Staff's approach is that the Companies are only providing the QF the opportunity to make a legally enforceable commitment to sell through negotiating a PPA, while the Public Staff's approach would allow a QF to lock in forecasted avoided cost rates without making a meaningful commitment to deliver power in the future.

The Companies recommend that the Commission direct the Public Staff, Dominion, and other parties to provide input on the proposed contracting procedures, which the Companies will revise, if needed, and then refile after the hearing.

Finally, my rebuttal testimony also briefly responds to SACE Witness Thomas Vitolo's speculation that reducing the standard offer eligibility to 1 MW will unreasonably increase the number of projects in the Companies' interconnection queues. As noted above, small projects eligible for the proposed 1 MW standard offer are more likely to pass the NC Interconnection Procedures Section 3 Fast Track screens, which provides a more streamlined interconnection study process. The Companies agree with the Public Staff that this is a practical reason for capping eligibility for the standard offer at 1 MW. This concludes my summary.

MR. BREITSCHWERDT: Thank you. Mr. Chairman, the panel is available for cross.

CHAIRMAN FINLEY: Cross examination.

MR. LEDFORD: Thank you, Mr. Chairman. My name is Peter Ledford with the North Carolina Sustainable Energy Association. I've got questions for -- we have questions for all three of the witness but I'd like to begin with Witness Bowman if that's okay.

CROSS EXAMINATION

BY MR. LEDFORD:

Q Ms. Bowman, on page 47 of your direct testimony you restate a portion of Order No. 69 to say and I quote, *One assumption underlying FERC's statement in Order No. 69 is that "in the long run, 'overestimations' and 'underestimations' of avoided costs will balance out"*. You then go on to assert that *The enormous recent surge in QF developments in North Carolina disproves this assumption*. Did Duke provide any support for this assertion?

A (MS. BOWMAN) I'm sorry, where are you reading from?

Q On your direct testimony, page 47, lines 12 through 17?

A Can you bear with me while I read that? I believe that the analysis that Witness Snider has provided is support for that statement.

Q Okay. So that's the only evidence that Duke has put forward to support that statement?

A Yes. That's the analysis that we have done --

Q Okay.

A -- looking at the contracts that we have already signed.

Q Okay. Turning to page 15 of your direct testimony, and it actually, this phrase appears throughout your testimony, you refer to the surging --

A Can you hold on until I get there, please?

Q Yes.

A What line are you on?

Q I'm on line 10.

A On page 15 of direct?

Q Yes.

A Okay.

Q You refer to PURPA's role in the quote, *surging and uncontrolled growth of utility-scale solar.*

A Yes.

Q I'd like to ask you some questions about your testimony that follows that statement including the graphs, excuse me, charts that are on pages 16 and 17.
A Okay.
Q Figure 1 on page 16 shows Cumulative Installed Capacity and the note below the figure says that it *Reflects 3rd Party-Owned Solar Capacity in North Carolina Only*. How much of this solar capacity is directly interconnected to DEC and to DEP?
A I believe Mr. Freeman knows that answer.
A (MR. FREEMAN) 100 percent of this is directly connected to either DEP or DEC.
Q So none of this is indirectly connected i.e., behind a wholesale meter?
A Subject to check, I believe it is not. It does not include anything behind the wholesale customers.
Q Okay. And is all of this PURPA capacity or is some of this capacity for REPS compliance or from previous RFPs for solar capacity?
A It's a combination of both.
Q Okay. So it is not exclusively PURPA QFs.

A Correct.
Q Turning to Figure Number 2 on the next page, this shows that roughly 4900 megawatts of proposed solar projects are either under construction or in development and requesting to interconnect. How much of this proposed capacity does Duke expect will actually materialize?
A (MS. BOWMAN) So I don't think we have any way of actually knowing how much will actually materialize. I think you can have guesstimates and I believe we might in the IRP -- if Mr. Snider would like to speak to that -- but at a minimum we are required by PURPA that, if it comes to fruition, we have to connect to it and we have to buy the output.

MR. LEDFORD: Mr. Chairman, if I could, I'd like to introduce NCSEA Cross Exhibit Number 1, which is their response to a data request from Duke.

CHAIRMAN FINLEY: The one page that Ms. Mitchell is passing out shall be marked for identification as NCSEA Panel Cross Examination Exhibit Number 1.

MR. LEDFORD: Thank you, Mr. Chairman.

NCSEA Panel Cross Examination Exhibit 1

(Identified)

BY MR. LEDFORD:

Q Ms. Bowman, have you had a chance to review the data response?

A Not yet.

CHAIRMAN FINLEY: I'll tell you what, Ms. Bowman, you take a little while to review that and we're going to break for lunch and come back at two o'clock.

A All right. Thank you.

(WHEREUPON, the proceedings were recessed.)

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell

Kim T. Mitchell
Court Reporter II