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

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

[PUBLIC]
DIRECT TESTIMONY OF
DR. BEN JOHNSON
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

I. INTRODUCTION

Q PLEASE STATE YOUR NAME, TITLE, AND EMPLOYER.

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

Q. PLEASE STATE YOUR EDUCATIONAL AND OCCUPATIONAL EXPERIENCE.

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

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

All told, I have participated in more than 400 regulatory dockets and provided expert testimony on more than 300 occasions before state and federal courts and utility regulatory commissions in 35 states, two Canadian provinces, and the District of Columbia. Most of this work has been performed on behalf of regulatory commissions, consumer advocates, and other government agencies involved in regulation. However, members of my firm and I have worked for other types of clients, including utilities (on rare occasions), firms that compete with utilities, large industrial customers, and non-profit organizations or trade associations.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

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

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

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

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

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

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

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

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

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

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

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

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

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

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

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

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

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

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

II. EXPIRING QF CONTRACTS

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

A. No. Duke has clarified some aspects of its approach, but it has not alleviated my concerns with respect to the treatment of existing QFs in North Carolina that have contracts expiring during the next 10 years. For example, the first concern discussed in my affidavit was that these QFs are currently helping to meet the utilities' capacity needs, and there is no principled basis for ceasing to pay them for the capacity costs they are helping to avoid, once their contracts come up for renewal. Duke sidesteps this concern without directly addressing it, or any of the associated public policy implications.

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

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

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

---

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

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

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

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

A discrepancy is almost inevitable because of the long lead times involved with planning and construction of new generating units. A utility typically commits to the construction of a new conventional generating unit at least three years before the new unit is actually needed, so the first date with a "need" shown in the IRP will typically be at least a few years away. In fact, the first date with a "need" that does not have a corresponding plan for meeting the need may be four or more years into the future. Due to the "lumpiness" of capacity additions, Duke maintains ample additional capacity over and above the minimum required reserve margin during years immediately after new units are added to the fleet – further delaying any "need" for new capacity.

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

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

Furthermore, a similar problem could arise at the expiration of the contract. There is no assurance that a "need for capacity that can actually be avoided" will be shown in the most recent IRP when the initial contract expires in 2028. More likely, at that point Duke's "most recent" IRP will show additional commitments have been made to meet the need that was originally projected for 2028, and therefore the first year with a "need for capacity that can actually be avoided" will then be several years later, when the contract is renewed. The net result could be a "catch-22" which systematically discriminates against QF during the contract renewal process, preventing them from being fully and fairly compensated for the capacity they provide.

Q. CAN YOU ELABORATE ON WHY IT WOULD BE INAPPROPRIATE TO REDUCE OR DENY QF CAPACITY PAYMENTS IN THIS MANNER?

A. Yes. Depending on how the concept of a "need for capacity that can actually be avoided" is applied to existing QFs, there may be no reasonable opportunity for them to achieve full capacity-cost recovery when their contracts are up for renewal. This would be deeply unfair to QFs who have invested in North Carolina on the reasonable expectation they will be fully and fairly compensated for the capacity benefits they provide – just as they were during the initial contract term. It would also be contrary to the public interest, because it would suggest a severe risk of arbitrary and unreasonable policy changes that will undermine investor confidence in the state legislative and regulatory policy-making apparatus.

Duke's approach would also be severely discriminatory, since it would only apply to QFs, and not to Duke – which would continue to receive full capacity-cost recovery for all of the generating units in its rate base, regardless of whether or when the utility's most recent IRP demonstrates a "need for capacity." This systematic discrimination would be inconsistent with PURPA and the associated FERC rules, which assume QFs will be provided with a meaningful opportunity to fully recover "capacity costs" when the QF commits to a long-term fixed price contract.

In general, the goals of PURPA and the interests of society as a whole, including the using and consuming public in North Carolina specifically, are best promoted when PURPA is implemented in a way that encourages QF competition. Under PURPA, QFs are generally entitled to be paid the full amount of avoided costs, including <u>both</u> energy and capacity costs if they commit to a long-term fixed-price contract. However, if a QF is only going to receive energy payments, it is entitled to sell its energy on an "as-available" basis – which provides the QF with maximum flexibility to attempt to sell its capacity to another buyer. Making capacity payments to existing QFs contingent upon a finding that additional new capacity is needed is fundamentally inconsistent with this structure, since it would deny QFs the opportunity to receive full payment for their capacity, even if they are willing to continue to commit their capacity to Duke at the end of their current contract.

As I discussed in my affidavit, DEC has numerous QF purchase contracts that are up for renewal over the next 10 years. If these existing contracts are appropriately analyzed, along with the planned upgrades to existing generating units and other factors discussed in my affidavit, I believe the Commission can, and should, conclude that DEC has a "capacity need" that is being served by these existing QFs. That need can also potentially be served by new QFs, to the extent some of the existing QFs do not renew their contracts. However, to be perfectly clear, regardless of how the Commission resolves this issue with respect to new QFs, I recommend it include language in its order which clarifies that QFs with contracts expiring between now and 2028 are fulfilling an existing capacity need, and they will not be denied a reasonable opportunity to continue to receive full capacity cost recovery regardless of whether or not new QFs will be paid for additional capacity they bring to the system.

I believe it would be a mistake to interpret HB 589 as requiring the Commission to "take" the capacity of small QFs without providing them with fair compensation for the value of what is being taken. This is not just a question of statutory interpretation, substantive due process or basic fairness – it is also a question of maintaining a healthy investment climate in the State. It would not be appropriate to adopt a policy which has the effect of systematically taking capacity from small QFs without giving them any reasonable opportunity to be fairly compensated for the capacity costs that are thereby avoided. This would discourage future QF investment in the state, and it could have broader implications – undermining investor confidence in the state legislative and regulatory policy-making apparatus – especially since that policy would be in direct conflict with the long-standing, well understood core principles of PURPA.

PURPA specifically states that QF rates must not "discriminate against qualifying cogenerators or qualifying small power producers."[3] Under rate base regulation, Duke is allowed to recover the cost of its new generating units once they are completed and put into commercial operation, as long as that capacity remains "used and useful" – even if the most recent IRP does not show a "need" for capacity during some years.

When Duke invests in generating capacity in North Carolina, it is not denied capacity cost recovery simply because a "need" for more capacity has not been demonstrated in the IRP for a particular year, or because subsequent investments are adequately meeting the capacity need that was initially fulfilled by that investment. Under nearly all circumstances, once an investment enters the rate base it remains there regardless of changing circumstances. QFs should be given reasonably comparable treatment.

To be clear, I am not suggesting that QF's should to be given, or need, the same level of cost recovery assurance that Duke enjoys. All that is needed is a legislative and regulatory environment that does not unreasonably discriminate against QFs. Simply stated, the Commission should continue to provide a reasonable opportunity for QFs to be fully compensated for the capacity costs they enable the utilities to avoid. If capacity is continuously provided by the QF, there should not be a gap in the payments they receive for avoided capacity costs each time their contract is renewed.

[3] 16 U.S.C. § 824a-3(a).

Q. DO YOU HAVE A RECOMMENDATION FOR HOW THIS CONTINUITY COULD BE ACHIEVED?

A. Yes. To ensure that the utility continuously and fully avoids capacity costs (without any gaps), the QF would need to sign a new contract several years before the old contract expires, or it will need to make a legally binding commitment to provide capacity before it signs the new contract. To facilitate the latter process, the Commission could require QFs to file notice with the utility at least 3 years before the current PPA expires indicating whether the QF is committing to continuously provide capacity and energy (without interruption) after the current contract expires – and specifying the length of that capacity commitment.

To the extent the QF confirms its capacity will be continuously available, the utility would include that capacity in the IRP – treating it as a committed generation resource, and the QF would be entitled to receive full avoided capacity payments without interruption for the full duration of the commitment period (with the actual payment rate and other details to be determined when the new contract is signed).

If a QF does not make a post-contract commitment, it will retain maximum flexibility to choose its course of action when the existing contract expires – including the option to sell power on an energy-only "as available" basis, or to sign a new fixed price contract at the same terms applicable to a new QF (e.g. with little or no capacity payments).

If the QF does not make a capacity commitment, or it only commits to a short period of time, the utility would exclude the QF's capacity from the IRP at the end of the contract term or commitment period. The removal of that capacity would be factored into the calculation of the extent to which a "need" for capacity exists each year – similar to the calculations that are developed when an existing generating plant is scheduled for retirement, or a wholesale purchase contract is expiring and is not expected to be renewed.

Q. WOULD THIS RESULT IN A MORE EFFICIENT PLANNING PROCESS AND USE OF GENERATION RESOURCES?

A. Yes. This proposal would ensure that existing QF capacity is included in the IRP process to only to the extent (and to the full extent) that QFs are actually committed to renewing their contract. The portion of capacity from expiring contracts that is not legally committed would still be evaluated in the IRP, but the associated uncertainties would be appropriately considered. For instance, the optimal strategy might be to plan on using short-term market purchases to fill the gap resulting from QF contracts that are not renewed, or to purchase capacity from new QFs instead. Constructing a new generating unit might be the logical option at a later time – once it is clear that certain QF capacity will no longer be available. The end result of this approach is to treat both new and existing QFs fairly, and to avoid the costly, inefficient duplication of generation resources.

III. ASSUMED IN-SERVICE DATE

Q. HAVE THE UTILITIES PROVIDED A VALID JUSTIFICATION FOR USING A JANUARY 1, 2019 IN-SERVICE DATE TO ESTABLISH QF RATES?

A. No. In my affidavit, I criticized the utilities for using January 1, 2019 as the starting point for their avoided cost and QF rate calculations. I explained that since the proposed standard offer tariff provides a single set of rates that will apply to all eligible QFs regardless of when they begin delivering power, a less arbitrary, more reasonable in-service assumption should be used. In their direct testimony, the utilities made very little effort to defend their assumed in-service date of January 1, 2019, nor did they offer any response to my concern that this assumption distorts all of the avoided cost calculations. Rather than just admitting the January 1, 2019 assumption is inaccurate, or offering to change this assumption, they concentrated on criticizing the alternative date of December 31, 2021 which I suggested in my affidavit.

Q. WHY IS NCSEA RAISING THIS ISSUE FOR THE FIRST TIME IN THIS PROCEEDING?

A. As other aspects of the QF rate development process have evolved, the impact of an inaccurate in-service date has become more evident and more serious. An inaccurate in-service date leads to inaccuracies throughout the rate-setting process. For instance, an unrealistically early in-service date results in QFs being compensated for avoided energy costs based on lower gas prices associated with an earlier set of years than the actual years when the QF will produce power – a time when the utility will actually avoid higher energy costs due to higher fuel prices. However, the problem has become particularly severe with respect to capacity costs, because the Commission is now including "zeros" in the capacity cost calculation. If capacity cost recovery is excluded during the initial years of a long-term contract, accurately determining the correct number of zeros to include in the calculations is vitally important; this requires an accurate assumption concerning the in-service date of the QF.

For example, consider a QF that provides capacity and energy to DENC starting in December 2021. Under the utilities' approach, if the QF signs a 5-year contract, it will be paid a levelized capacity rate based on DENC's avoided capacity costs during two years: 2022 and 2023; zero capacity costs will be assumed for the remaining three years. The problem is that DENC assumes the QF will provide power during 2019, 2020 and 2021, which are years when capacity costs are deemed to be unavoidable, when in reality power will be delivered during a later time frame. If the QF is actually energized in December 2021, it will enable DENC to avoid capacity costs throughout the entire 5-year contract term of 2022-2026.

The problem would be diluted, but not eliminated, if the QF signs a 10-year contract. In that case, the QF will provide power during the years 2022-2031, but the rate calculations will assume it provides power during

2019-2028. As a result of this timing discrepancy, the QF will only be paid for avoided capacity costs during 7 years of the 10-year term. In reality, DENC will avoid capacity costs during all 10 years of a 2022-2031 contract duration, but this is not recognized when the rates are calculated. Similar problems apply to DEC and DEP, with the specific impact depending on the number of zeros included in their capacity rate calculations.

This problem was not as evident in previous biennial proceedings, since the Commission had rejected proposals to include zeros in the capacity rate calculations. In past proceedings, the Net Present Value calculations included capacity costs for all 5 years of a 5-year contract (or all 10 years of a 10-year contract) regardless of what in-service date was assumed. Accurately determining the correct number of zeros was not an issue, since there were no zeros in the calculations.

Strictly speaking, a more accurate in-service date will improve the accuracy of all aspects of the rate calculations. For instance, there could be differences in the overall inflation rate compared to the inflation rate applicable to the cost of a new CT, or differences between the percentage factors that are used in calculating the return on investment compared to the discount factors that are used in developing the Net Present Value and levelized annual rate calculations. However, those impacts are relatively minor, and not as clearly demanding a need for improved accuracy as when zeros are being used in the calculations.

Q. **CAN YOU EXPLAIN WHY YOU THINK FEW QFS WILL ESTABLISH LEOS BEFORE NEW RATES ARE FINALIZED?**

A. Yes. Mr. Petrie wondered what support I had for this assertion:

> Dr. Johnson offers no support for his assertion that few QFs are likely to seek to establish LEOs under the new rates until after the rates have been finalized...[4]

I based this statement on my general understanding of the industry, my review of the proposed tariffs, and my review of historical LEO data provided by the utilities in response to discovery, which shows **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

My reasoning is straightforward: QFs are reluctant to commit to a Legally Enforceable Obligation unless and until they have a reasonable degree of assurance that their proposed project will be economically viable. The proposed standard offer tariffs have low QF rates that are fixed for a relatively short period of time, and the tariffs include proposals (especially with respect to solar integration costs) that would increase the risks and uncertainties facing new QF projects. Accordingly, at the time I prepared my affidavit I anticipated that relatively few QFs will commit to a LEO before they know more about the Commission's response to these proposals. This will place

[4] *Direct Testimony of Bruce E, Petrie on Behalf of Dominion Energy North Carolina*, p. 19, Docket No. E-100, Sub 158 (May 21, 2019) ("Petrie Direct").

them in a better position to evaluate whether or not a project will be economically viable.

More than 6 months having now elapsed since the proposed rates were filed; if a large number of QFs are willing to commit to a LEO without seeing significant improvement in the proposed tariffs, that trend will already be apparent. Accordingly, the utilities can clarify the record by bringing forward data to show how many QFs have established LEOs in recent months. This data could also be useful to the Commission in determining whether there are any projects that have already been energized that will be paid the standard offer rates established in this proceeding. All of this information will be useful in helping the Commission to judge the reasonableness of my original statement, as well as the reasonableness of the proposed assumed in-service date of January 1, 2019.

Q. YOU MENTIONED HISTORICAL LEO DATA. CAN YOU PROVIDE SOME INSIGHT INTO THIS DATA?

A. Yes. The utilities provided detailed historical data from both North and South Carolina which confirms that an in-service date of January 1, 2019 is not realistic, since this is just 60 days after the tariffs were filed.

The largest, most detailed data set was obtained from DEP, so I will focus on that. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**

However, these statistics understate the lengthy time lines involved with QF project development, or the degree to which the proposed in-service date is unrealistic, because very few projects obtain their LEO immediately after a biennial rate filing. In most cases there is a substantial additional gap between the date when the standard offer tariff is filed and the LEO date. Consider, for example, the current biennial proceeding. If roughly half the projects that will sign a contract during the 2019-2020 biennial period commit to a LEO during 2019 or sooner, and the other half commit to a LEO during 2020, the median LEO date will be sometime around January 1, 2020. Accordingly, taking all of the various delays into consideration, the historical data suggests the majority of the projects falling within the current biennial time frame will probably not be energized until 2021; very few (if any) will be energized on or before January 1, 2019.

Q. THE UTILITIES CRITICIZED YOUR SUGGESTED ALTERNATIVE ASSUMPTION OF DECEMBER 2021. WHAT IS YOUR RESPONSE?

A. By its very nature, a single assumed in-service date will not precisely align with the actual in-service date of every QF. Hence, I was never intending to suggest that it would be infeasible for a QF to energy a project before December 2021. The key point I was making in my affidavit is that a more accurate and reasonable in-service assumption is needed. It was not my intent, and is not my recommendation, to substitute one inaccurate assumption for another. I continue to believe it is completely unrealistic to assume an in-service date of January 1, 2019 for QFs that sign a contract during the 2019-2020 biennial period. With a more appropriate, realistic assumption, roughly half the QFs should end up having an actual in-service date before the assumed date, and roughly half should have an in-service date after the assumed date. I see no conceivable possibility that half of the QFs signing contracts during this biennial period will have an in-service date on or before January 1, 2019.

While I still believe December 2021 is a reasonable alternative, I agree that small QFs proceeding under the Fast Track and Supplemental Review process can proceed more expeditiously than larger projects. Accordingly, it might make sense to use an earlier in-service assumption for these smaller projects than for larger projects. I would point out, however, that a specific assumed date is not the only option. Another solution would be for the Commission to require the utilities to publish a schedule of rates (or a formula) that specifies the applicable rate for all projects signing a contract during the

2019-2020 biennial period. Each QF would receive the applicable rate based on its actual in-service date.

This schedule of rates (or formula) could vary at intervals as frequently as monthly, or as infrequently as once a year. If the rate varied annually, projects energized during 2019 would receive payment based on an assumed in-service date of July 1, 2019, projects energized during 2020 would be paid based on an in-service date of July 1, 2020, projects energized during 2021 would be paid based on an in-service date of July 1, 2021, and projects energized during 2022 would be paid based on an in-service date of July 1, 2022.

Q. HOW DID THE UTILITIES RESPOND TO YOUR SUGGESTION THAT RATES COULD VARY DEPENDING ON THE ACTUAL IN-SERVICE DATE?

A. Duke's witness ignored this option, while Mr. Petrie (testifying on behalf of DENC) apparently found it confusing:

> Dr. Johnson's proposal that the Utilities should calculate capacity costs for negotiated PPAs individually based on projected in service date, and present a range of rates based on different in-service dates, should be rejected for similar reasons.
>
> ...this approach would be inconsistent with prior precedent and would unreasonably burden the Utilities by requiring them to provide multiple pricing choices to developers from which the developer can choose the most beneficial.
>
> ...This would also make the negotiated PPA process more inefficient, as it would likely lead to disagreements about in-service dates. For example, what happens if the QF's anticipated in-service date that was agreed upon or anticipated when the PPA is negotiated shifts due to

> interconnection study process? Would the utility be required to recalculate the rates? The proposal presents too many uncertainties to be appropriate.[5]

These criticisms are misplaced, because NCSEA was not, and is not, proposing to tie rates to an anticipated or projected in-service date. Rather, the rate would be based on the <u>actual</u> in-service date. This reduces or eliminates the risk of under-payment if the project begins commercial operation after the assumed or anticipated in-service date; similarly, it reduces or eliminates any risk of over-payment if the QF begins commercial operation before the anticipated or assumed in-service date.

If rates are tied to the actual in-service date, rather than an assumption or projection, there would also be no reason to anticipate difficulties in negotiations or disagreements about the in-service date. The schedule of rates, or rate formula, would be set forth in the tariff or attached to the negotiated contract, based on a straightforward application of the same methodology that is currently being used to estimate avoided energy and capacity costs. The only difference would be the time frame used to develop the avoided cost estimates – it would match the time frame when power will actually be delivered.

There would also be no requirement for the utility to recalculate rates if delays are encountered during the interconnection or construction process. The schedule of rates or formula can be set forth in the tariff, or attached as

---

5 *Id.* at pp. 17-18.

an exhibit to a negotiated contract, so both parties will always know the impact of any actual or potential schedule changes on the rates that will be paid to the QF. There would be no room for confusion or disagreement about what rate is going to apply in any given situation – the rates are established in the tariff or contract, contingent on the actual date when the project goes online and begins delivering energy to the grid. Nor is there any reason for confusion about this date – it could be determined in the same way the utility determines whether the QF is delivering power in sufficient volume to entitle it to compensation pursuant to the contract.

Q. WOULD IT BE DIFFICULT OR BURDENSOME FOR THE UTILITIES TO CALCULATE A SCHEDULE OF RATES TIED TO THE ACTUAL IN-SERVICE DATE?

A. No. It would not be difficult for the utilities to run their rate calculations using different assumed in-service dates. The utilities could modify their workpapers to treat the in-service date as a variable which can be adjusted in the same way "what if" scenarios are routinely handled in computer modeling. An even simpler alternative would be for the utilities to make some copies of their workpapers, and then manually revise the relevant portions of each copy as necessary to be consistent with an alternative in-service date.

Q. YOU MENTIONED THE POSSIBILITY OF ESTABLISHING A SCHEDULE OF RATES THAT VARIES TWICE-ANNUALLY, OR EVEN MONTHLY. IS THIS FEASIBLE?

A. Yes. If the utilities decide to modify their workpapers to treat the in-service date as a variable, they could do this in a way that makes it easy to produce a different answer for each month. If they decide instead to make copies of their workpapers, and manually revise them to use an alternative in-service date, it wouldn't be necessary to do this for every month. In fact, a simplified approach might suffice – creating one set of workpapers for the earliest relevant date (e.g. January 1, 2019) and another set for the last potentially relevant date (e.g. January 1, 2023). Rates can easily be calculated for any month in between these "bookends" using mathematical interpolation.

Q. THE UTILITIES CONTEND THAT RATES DO NOT HAVE TO PRECISELY RECOGNIZE THE UTLITY'S ACTUAL AVOIDED COSTS. HOW DO YOU RESPOND?

A. I agree that perfection is not required, and some degree of simplification is reasonable and sometimes necessary. However, the desire for simplicity (or the extra work required to solve a problem) should not become an excuse for allowing the calculations to become biased against QFs. If a single assumed in-service date is going to be used, it should be a realistic one which does not bias the rates downward. If the parties can't agree on an appropriate in-service date, it would make sense to adopt a schedule of rates that allows each QF to be paid based on its actual in-service date. The additional effort required to implement such a schedule of rates would be minor compared to the importance of this issue, and the potential impact on future QF development in the state.

During the past several biennial proceedings, the utilities have pushed for multiple changes to the process they use in calculating avoided costs and setting QF rates. Some changes were controversial; others were not. Some of these changes had the effect of improving the accuracy and precision of the rate calculations; others did not. One thing nearly all of the utilities' proposed changes have had in common is the direction of the change: they nearly always have had the effect of pushing QF rates downward.

Given the importance of QF rates for all of the parties involved in these biennial proceedings, it makes sense for the Commission to improve the accuracy and precision of the rate-setting process where this is feasible. This helps protect the interests of the using and consuming public because it moves closer to the ideal situation under PURPA, where QF rates are precisely equal to avoided costs – no higher and no lower. While it may be impossible to fully achieve this ideal result, it makes sense for the Commission to move in this direction.

The trend towards improving the calculations should not be a one-way street. Proposed improvements that have the effect of decreasing QF rates should not be given preference over improvements running in the other direction. Increasing the accuracy of the in-service date is an appropriate step to take – one that will provide further confirmation that the regulatory process is not biased for or against any particular interest group, and that improvements are not contingent upon the willingness of the utilities to do the work needed for their implementation.

IV. GRANULAR RATE DESIGN

Q. WHAT IS YOUR INITIAL REACTION TO THE RATE DESIGN STIPULATED BY DUKE AND THE PUBLIC STAFF?

A. The energy rate design in the stipulation filed by Duke and the Public Staff on April 18, 2019 is similar to the alternative described in my affidavit at paragraphs 200-206. For the same reasons explained in my affidavit, I believe this stipulated energy rate design is a step in the right direction. However, it does not go as far as it could.

In my affidavit, I identified three major areas where increased granularity and accuracy would be beneficial and feasible: (a) geographic diversity, (b) stable and predictable cost variations based on seasonal and hourly patterns, and (c) less stable and less predictable cost variations due to weather fluctuations. I recommended improving the QF rate design in all three of these areas, in order to improve economic efficiency, to encourage entrepreneurial experimentation and innovation, and to encourage better investment decisions.

The stipulated energy rate design is a significant improvement compared to both the status quo and the rate design initially proposed by the utilities in this proceeding in one of these three areas: variations in avoided energy costs based on seasonal and hourly patterns. The stipulation does not offer any improvements with respect to avoided capacity costs or with respect to geography and weather fluctuations.

Q. ARE FURTHER IMPROVEMENTS FEASIBLE WITH RESPECT TO HOURLY AND SEASONAL COST PATTERNS?

A. Yes. Price signals could be further improved by calculating separate rates for each hour of each month. This approach would provide 288 separate price signals that can be succinctly displayed in a simple matrix of 12 columns (representing months) and 24 rows (representing each hour of the day). While this might seem more complex, it would actually be easier for QFs to analyze and respond to this 12x24 matrix than the less granular design used in the stipulation.

Improved granularity does not require more complexity because the 12x24 approach eliminates the complications associated with weekends and holidays, as well as the complexities associated with daylight savings time. I am not denying that load variations and cost differences can exist arise with respect to week days, weekends, holidays and daylight savings time. However, these nuances are not of great importance in this context and capturing them is not a high priority in the context of QF rates.

QFs have very little opportunity to respond to differences in the price they receive during a week day compared to a weekend or on a holiday. The rain falls and the sun shines the same on a Thursday or Friday as the following

Saturday; the fact that one is a week day and the other is a weekend doesn't have any significance for the design, engineering and operation of a typical hydro or solar facility. Similarly, there little to be gained by adding complexity to a QF tariff in order to keep track of timing differences related to daylight savings time. Solar output and ambient temperatures are the same whether it is 3 pm Eastern Daylight Time ("EDT") or 2 pm Eastern Savings Time ("EST").

This is not to say that these complexities are equally unimportant in the context of retail tariffs which may have originally formed the basis for the approach used in the utilities' QF tariffs. In the case of commercial and industrial customers, tariff distinctions related to week days, weekends, holidays and daylight savings time can influence decisions relating to their hours of operation, how many employees are assigned to work during different time periods, and other decisions that influence energy usage patterns. Distinctions that are given priority a retail rate context are not necessarily as important in the QF rate context.

It makes more sense to give priority to sending granular price signals that allow more precise alignment with monthly variations in hydro flows and the movement of the sun, as well monthly variations in the timing of when cloud coverage and rainstorms tend to occur. A 12x24 rate design provides more precise price signals, which makes it possible to more precisely match QF revenues to avoided costs, and which can improve economic efficiency by helping QFs make better decisions with respect to the design, engineering and operation of their facilities. This increased granularity will become increasingly significant as storage technologies become more widespread, allowing QFs (including ones that will be renewing their contracts in the future) to fine-tune their responses to the QF rates.

Accordingly, while I applaud Duke and the Public Staff for taking a significant step in the right direction, I recommend the Commission seriously consider going even further in the direction of greater granularity. The 12x24 rate design facilitates more precise price signals without any greater complexity.

Q. ARE FURTHER IMPROVEMENTS FEASIBLE WITH REGARDS TO WEATHER FLUCTUATIONS?

A. Yes. Stronger, more precise price signals could be achieved by implementing Real Time Pricing during extreme conditions – the relatively small number of hours when system costs are extremely high or extremely low. Fixed prices would continue to be applied during the vast majority of the hours each year, thereby providing QFs and their investors with adequate revenue stability and predictability.

Q. DID THE UTILITIES DISCUSS THIS NCSEA PROPOSAL IN THEIR DIRECT TESTIMONY?

A. No. My impression is that the utilities do not dispute the fact that more accurate avoided cost recovery can be achieved by using real time pricing during a small number of hours when costs happen to be unusually high or low. The approach described in my affidavit at paragraphs 207 – 217 would support increased pricing accuracy without damaging the ability of QFs to obtain financing, because the vast majority of their revenues would continue to be received through fixed prices that are specified in the power purchased contract, and because reasonable limitations would be placed on the utilities' discretion in applying real time pricing.

Neither Duke or DENC disputed the merits of real time pricing, but they seem to have some qualms about practical implementation issues. Duke did not discuss this NCSEA proposal in its testimony, but it expressed these concerns in its reply comments:

> ...although the Companies agree that time-of-day pricing periods and real-time pricing tariffs for QFs could better align the Companies' actual avoided costs to QF payments, the Companies believe that the more granular pricing periods they have proposed in this proceeding are sufficient at this time. However, as technological advancements are made and more granular pricing becomes less costly and burdensome to administer, the Companies agree to investigate development of time-of-day and real-time pricing periods for standard offer QFs.[6]

It is unclear what "technological advancements" Duke is hoping will become available, or why it believes the concept could be burdensome. DENC more clearly stated its concerns:

> ...incorporating real time pricing [in]to the rate design would unreasonably increase the time and costs of

[6] *Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Docket No. E-100, Sub 158 (March 27, 2019) ("Duke Reply Comments"), pp. 74-75.

> administering standard offer PPAs due to the need for additional personnel and processes to monitor the likelihood and duration of these extreme events.[7]

Q. WHAT IS YOUR RESPONSE TO THESE CONCERNS?

A. I agree these sorts of practical concerns need to be considered, but at most they suggest a need to move cautiously and carefully; they do not provide a valid reason to summarily reject the NCSEA proposal.

All (or nearly all) existing QFs already have their output metered on an hourly or sub-hourly basis, so there is no problem with obtaining the data needed to apply real time pricing during hours when extremely high or low-cost conditions exist. Similarly, practical technological solutions already exist for communicating with QFs to let them know in real-time that extreme cost conditions are anticipated and very high or low pricing may be applied, which will enable the QF to effectively prepare for and respond to the extraordinary cost conditions. These existing technologies include text messages and emails, as well as posting information on the Internet. These communications methods do not require a large amount of effort and the would not be difficult or unreasonably costly to implement.

Similarly, the utilities already have personnel on staff who are monitoring the likelihood and duration of unusual weather conditions (which is what triggers extraordinarily high or low-cost conditions). This is

---

[7] *Reply Comments of Dominion Energy North* Carolina, Docket No. E-100, Sub 158, (March 27, 2019) ("Dominion Reply Comments"), p. 25.

information the utilities need to continuously monitor and evaluate, in order to cost-effectively plan and dispatch their systems, so there would be no need to add additional personnel in order to anticipate and identify times when extremely high or low-cost conditions may occur. Nor would it require a substantial amount of time and effort for existing employees (who are already collecting and analyzing this information as part of their day-to-day responsibilities) to pass this information along, so that times when real time pricing would be appropriate can be identified. The key step – one that would not be unduly burdensome – is to pass this information through to QFs, so they can respond to more accurate price signals during times when costs are extremely high or low.

Q. DENC'S LMP TARIFF IS ENTIRELY BASED ON GEOGRAPHICALLY SPECIFIC REAL TIME PRICING. IS THIS AN APPROPRIATE WAY TO PROVIDE MORE ACCURATE TIME OF DAY AND GEOGRAPHIC PRICE SIGNALS?

A. No. The LMP tariff is not as good a solution as the NCSEA proposal described in my affidavit, because the LMP tariff tightly links the QF's revenues to volatile natural gas and other energy markets. Since most QFs have low variable costs and high fixed costs, this volatility is fundamentally incompatible with the underlying cost structure of most QFs (the most important exception being gas-fired cogenerators). Hence, the LMP rate design is inappropriate for most QFs since it forces the QF to endure significant, unnecessary risks, and it makes it very difficult to project future revenue streams or to obtain debt financing.

Q. CAN THE COMMISSION CAUTIOUSLY MOVE TOWARD MORE ACCURATE, GRANULAR QF PRICES IN THIS PROCEEDING?

A. Yes. It is feasible to move toward more accurate price signals in all three areas: (a) geographic diversity, (b) stable and predictable cost variations based on seasonal and hourly patterns, and (c) less stable and less predictable cost variations due to weather fluctuations. The stipulated rate design makes progress with respect to seasonal and hourly patterns, but greater accuracy is worth pursuing by adopting the 12x24 pricing matrix. Similarly, given the importance of QF power to the utilities' operations, I believe the Commission should push the utilities to make further improvements with respect to geographic cost differences and the application of real time pricing during a small number of extraordinarily high or low-cost hours.

More accurate prices will protect the interests of the using and consuming public by moving closer to the ideal situation where QF rates are precisely equal to avoided costs – no higher and no lower. The Commission can move forward in a cautious, deliberate manner by including language in its final order directing the utilities to develop detailed plans for how they would go about implementing geographically granular rates and real time pricing during a small number of hours, for the Commission's consideration in a future proceeding. This detailed planning process would include identifying and analyzing any relevant administrative or practical problems, and developing proposed strategies for overcoming or minimizing these problems.

The Commission should require the utilities to submit their proposed plans at least 6 months before their tariff filings in the next biennial proceeding, to provide ample opportunity for the Public Staff and other interested parties to review the plans, and to work with the utilities in developing potential improvements, refinements, or alternatives for the Commission's consideration during the next biennial proceeding.

IV. SEASONAL CAPACITY COST ALLOCATIONS

Q. WHAT IS YOUR REACTION TO THE CAPACITY RATE DESIGN AND SEASONAL ALLOCATION INCLUDED IN THE STIPULATION SIGNED BY DUKE AND THE PUBLIC STAFF?

A. The stipulation retains all of the flaws in this aspect of Duke's initial filing in this proceeding. The stipulation allocates 100% of DEP's capacity costs and 90% of DEC's capacity costs to the months of December through March. The remaining 10% of DEC's capacity costs are allocated to the months of July and August. The net result is to unreasonably reduce (and in fact, to entirely, or almost entirely, eliminate) capacity payments to QFs during the summer. The stipulated seasonal cost allocations are inconsistent with the underlying reality that DEC and DEP serve loads that primarily peak during the summer, just like the loads experienced by the PJM system to the north, the Tennessee

Valley Authority ("TVA") to the west, Georgia Power to the south and South Carolina Electric & Gas to the east.

Viewing the DEC and DEP systems as predominantly winter peaking is inconsistent with the way these neighboring utilities are viewed, as well as the underlying reality that: (a) long, hot summers occur every year in this part of the country; (b) mild winter days are a frequent occurrence, and uncommonly cold weather rarely lasts for more than a few hours over the course of a few days; (c) virtually all businesses and residences rely on electricity for air conditioning, but many of these customers do not rely on electricity for heating, because natural gas heating offers a viable alternative during the winter.

It is also worth noting that DEC and DEP are continuing to function like summer peaking utilities with respect to some other issues, including the way they have designed and implemented their retail rates, and the way they have designed and implemented their Demand Side Management ("DSM") programs. In fact, one would be hard pressed to find any significant aspect of their operations which has significantly changed in ways that would suggest DEC and DEP truly believe their winter peaks are now more important than their summer peaks.

Q. DID DUKE PROVIDE ANY NEW EVIDENCE TO SUPPORT THE SEASONAL ALLOCATION IN THE STIPULATION?

A. No. Essentially the only support for this aspect of the stipulation in Duke's direct testimony was a perfunctory reference to the loss of load risk that Duke's consultants, Astrapé, developed in its Solar Capacity Value Study.

> ...it is reasonable and appropriate to adopt the Companies' seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the Astrapé Solar Capacity Value Study. The loss of load risk identifies the times when the Companies forecast generation constraints making QF generation of the greatest value to customers. [8]

Duke did not offer any other evidence in its direct testimony to support the capacity rate design and cost allocation in the stipulation. Tellingly, Duke's direct testimony largely ignored the flaws in its solar modeling, and that of its consultants, which were extensively discussed in my affidavit (e.g. paragraphs 35 – 50) and in my report (e.g. pages 14 – 17 and 25 – 29). The failure to respond to these criticisms is significant in this context, because the Solar Capacity Value Study is heavily dependent upon the assumptions and methodology used in modeling solar output.

The modeling flaws and other problems discussed during the comments phase of this proceeding help explain how it was possible for Duke's consultants to reach the conclusion that nearly all of the loss of load risks are concentrated in the winter months, despite the fact that DEC, DEP and other nearby utilities have long been viewed as summer peaking.

[8] Snider Direct, p. 26.

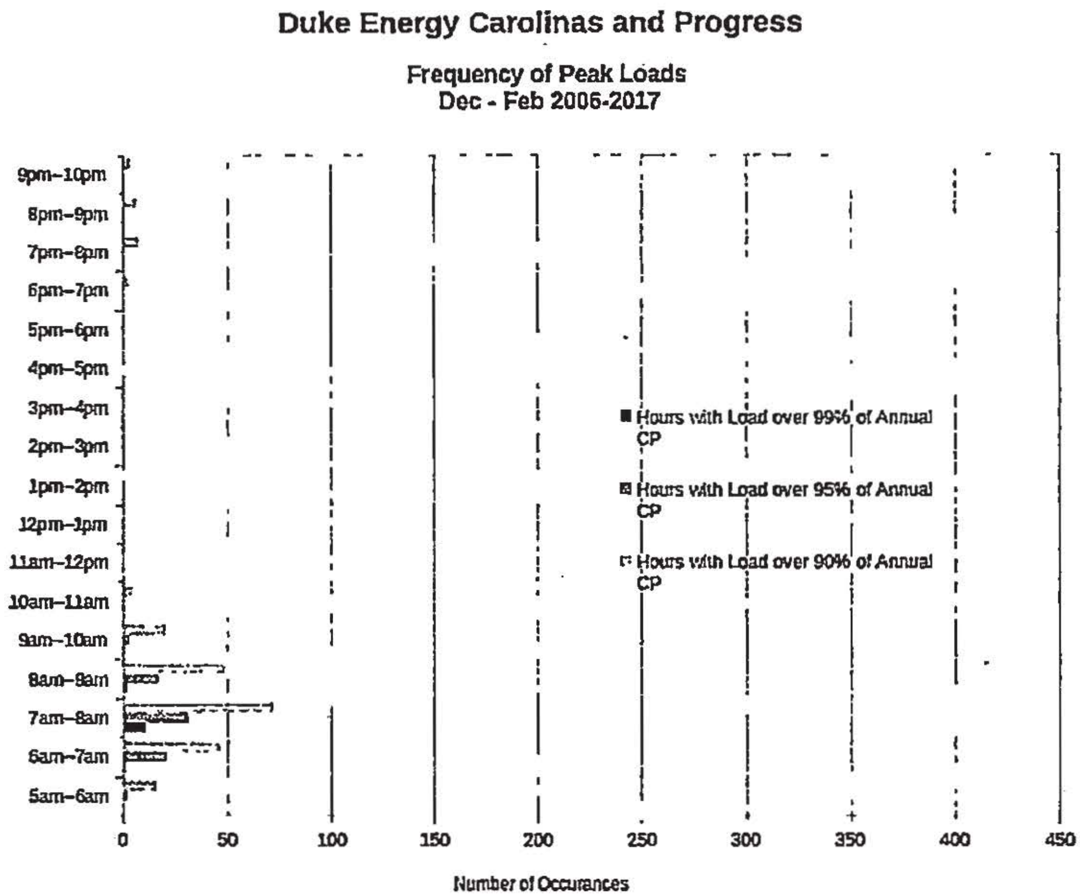
Q. IS THERE EVIDENCE IN THIS PROCEEDING WHICH CONTRADICTS THE CAPACITY COST TREATMENT IN THE STIPULATION?

A. Yes. Consider, for example, data related to Duke's decision to focus on July and August, to the exclusion of other summer months. In paragraph 104 of my affidavit, I pointed out that the highest peak in June or September is often close to the highest peak in July or August. In fact, during 2015 the DEC peak in June (20,003) slightly exceeded the peaks in July and August, and the peak in September (18,681) was not far behind. DEP experienced a somewhat similar pattern of monthly peaks that year, with the June peak (12,849) exceeding the July and August peaks. Another example occurred in 2014, when the DEP September peak exceeded the July and August peaks. Similarly, the June peak exceeded the July and August peaks in 2008. The DEC peak in June 2008 also exceeded the July and August peaks that year. Duke did not dispute any of this data, or offer any justification for narrowing the focus to just two summer months in the stipulation – except for the loss of load risk estimates which Astrapé developed using a flawed modeling approach.

Since peak load patterns are normally used to determine the allocation of capacity costs and the design of capacity-related rates, this data strongly suggests that at least some of the capacity costs should be allocated to June and September, along with the months of July and August. Although this data discussed earlier in the proceeding it was simply ignored in developing the stipulation and Duke's direct testimony.

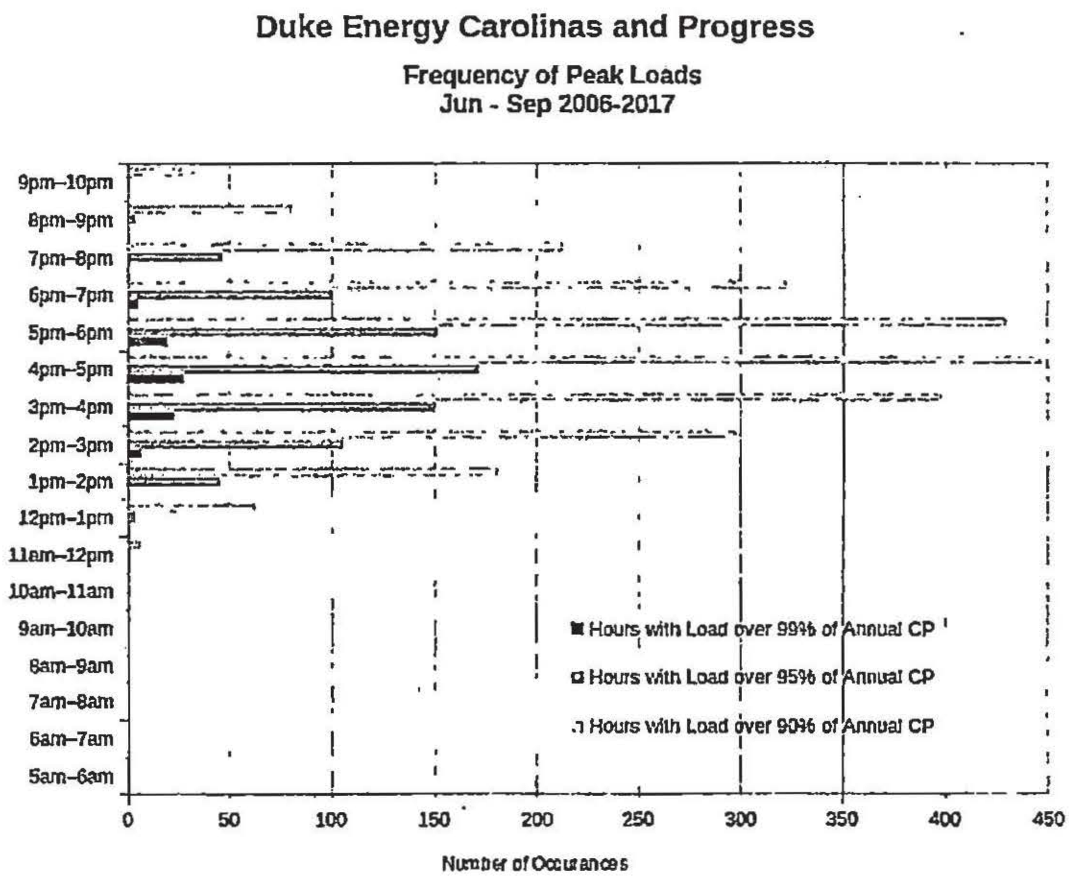
Another example is the hourly load data reported to the FERC on Form 714, which was discussed in my report. This data shows there are very few hours when high levels of peak usage occur during winter months, compared to the much larger number of hours when high levels of peak usage occur during summer months.

The following graph, which was included in my report, shows there were just 14 hours during the months of December through February during the years 2006-2017 when peak usage exceeded 99% of the annual coincident peak. Similarly, it shows there were 74 hours during those months when peak usage exceeded 95% of the annual peak and 241 hours when peak usage exceeded 90% of the annual peak.



High system peaks occur far more frequently in the summer. For example, according to the hourly load data reported to the FERC on Form 714, there were 84 hours during the months of June through September during the years 2006-2017 when peak usage exceeded 99% of the annual coincident peak. Comparing 84 hours to 14 hours, it is clear that, despite the fact that extremely cold weather can result in extremely high levels of peak usage in some years, usage in excess of 99% of the annual peak still occurs far more frequently in the summer than in the winter.

The discrepancy between summer and winter is even more dramatic with respect to the highly elevated levels of peak usage which occur more frequently, and are also an important contributor to peak capacity costs. For instance, there were 783 hours during the summer when peak usage exceeded 95% of the annual peak and 2,479 hours when peak usage exceeded 90% of the annual peak. All told, usage in excess of 95% of the annual peak occurs 958% more frequently in the summer than in the winter, while usage in excess of 90% of the annual peak occurs 929% more frequently in the summer than in the winter, as shown in the following graph:



This data confirms that DEC and DEP are largely summer-peaking utilities, for the simple reason that the demand for electricity is much stronger in the summer than in the winter and very hot summer days are far more common than very cold winter days. Common sense and economic theory both suggest that a large share of capacity costs should be allocated to the summer. There is simply not any historical data to support the idea that it is appropriate to allocate all, or nearly all, capacity costs to the winter. Perhaps that is why Duke did not discuss any of this historical load data in its direct testimony, and instead referenced the loss of load estimates developed by its consultant, Astrapé.

Q. THE STIPULATION ALLOCATES CAPACITY COSTS TO MARCH BUT THE DATA YOU JUST DISCUSSED EXCLUDES MARCH. CAN YOU COMMENT ON THIS DISCREPANCY?

A. Yes. The historical load data does not support allocating capacity costs to March, which is why I left this month out of this discussion and the graphs that were included in my report. To state this even more clearly, there were no hours when peak usage exceeded 99% of the annual coincident peak and no hours when peak usage exceeded 95% of the annual peak during March during any of the years from 2006 through 2017. There were 11 hours when peak usage exceeded 90% of the annual peak in March during the years 2006-2017, but this number pales in comparison to the analogous figure of 2,479 hours during June through September of those same years.

Q. WHY DOES THE STIPULATION INCLUDE MARCH, YET EXCLUDE JUNE AND SEPTEMBER?

A. Duke chose not to give any weight to the historical data and instead focused entirely on the loss of load risk estimates provided by its consultant.

Q. WHY ARE THE LOSS OF LOAD ESTIMATES SO DIFFERENT FROM THE HISTORICAL DATA?

A. There are multiple factors contributing to this discrepancy. At least in part, the Astrapé loss of load risk estimates are inconsistent with the historical data because they were developed using unreliable assumptions and modeling techniques. These problems include flawed solar modeling, as discussed in my affidavit and my report, as well as the assumption that Duke's DSM programs would continue to primarily focus on summer peaks, instead of being transitioned to give equal or greater emphasis to winter peaks.

Q. CAN YOU BRIEFLY EXPLAIN THE PROBLEM WITH THE DSM ASSUMPTIONS?

A. Astrapé assumed Duke's time of day rates, energy efficiency efforts and other DSM programs will continue to primarily target summer peaks. If winter peaks were truly becoming the most serious problem, and loss of load risks in the summer were truly diminishing in importance to the point where 0% (DEP) to 10% (DEC) summer allocation factors were appropriate, it would no longer make sense to provide customers with an economic incentive to reduce their load during summer peak hours. Similarly, if winter loss of load risks were truly increasing to the point where a 90% (DEC) to 100% (DEP) winter allocation factor were justified, it would be cost effective and appropriate to dramatically increase efforts to incentivize customers to reduce their load during winter peak hours. Neither DEC nor DEP have implemented these changes yet – calling into question how strongly they are committed to the argument they are now winter peaking utilities.

In any event, to the extent a shift in risk is occurring from summer to winter, this changing risk pattern should have been recognized by Astrapé in the assumptions it adopted with respect to the DSM programs. To maintain consistency with a changing risk profile, and to accurately estimate the actual loss of load risks that exist in each season, the DSM assumptions should have been modified to reflect the growing importance of winter risks and diminishing importance of summer risks. Succinctly stated, summer DSM programs would no longer be cost-effective if summer peaks were no longer important; this would eliminate any justification for maintaining these programs at the current levels, thereby negating any justification for assuming the status quo will be maintained.

If Astrapé had used more appropriate DSM assumptions, it would have estimated lower risk in the winter (due to more winter DSM) and more risk in the summer. With logically consistent DSM assumptions, the net result would still reflect some movement away from summer risk toward increased winter risk, but the shift in risk would not be overstated, as it is with the assumptions used by Astrapé.

Q. IS THERE ANOTHER REASON YOU DISAGREE WITH THE SEASONAL ALLOCATION FACTORS IN THE STIPULATION?

A. Yes. In the 2018 IRP filings Duke explained that one of the primary motivations for shifting its primary focus to winter peaks is the increasing availability of solar capacity during the summer:

> In the past, loss of load risk was typically concentrated during the summer months and a summer reserve margin target provided adequate reserves in both the summer and winter periods. However, the incorporation of recent winter load data and the significant amount of solar penetration included in the 2016 study, shows that the majority of loss of load risk is now heavily concentrated during the winter period. The seasonal shift of LOLE to the winter period also increases as greater amounts of solar capacity are added to the system. Thus, increasing solar penetrations shift the planning process to a winter focus.[9]

This explanation confirms that Duke is evaluating loss of load risks primarily on a "net" basis, after taking into account the fact that solar capacity is helping meet the summer peaks and this benefit will increase as additional solar projects are connected to the grid. Solar capacity helps Duke serve peak levels of customer demand during hot summer afternoons; without this capacity loss of load risks would be much higher, and Duke would incur the cost of obtaining capacity from some other source.

---

[9] *Duke Energy Carolinas, LLC 2018 Integrated Resource Plan and 2018 REPS Compliance Plan*, Docket No. E-100, Sub 157 (September 5, 2018) ("DEC IRP"), p. 38; *See also Duke Energy Progress, LLC 2018 Integrated Resource Plan and 2018 REPS Compliance Plan*, Docket No. E-100, Sub 157 (September 5, 2018) ("DEP IRP"), p. 38.

Duke is evaluating loss of load risks on a "net" basis (after considering the benefits of solar capacity) in the IRP to help evaluate the optimal timing of when new generating capacity will need to be added. Whatever the merits of this approach in the context of the IRP, it is <u>not</u> appropriate to focus exclusively on "net" loss of load risks when developing the QF rates, as Duke is doing in this proceeding. By focusing on these "net" loss of load risks Duke is attempting to justify summer allocation factors that deny solar QFs any reasonable opportunity to be fully compensated for the capacity benefits they provide during the summer. The effect is to "take" capacity that is clearly needed to help protect against blackouts (or loss of load) during the summer, without fairly compensating the solar QFs that are providing this capacity. Not only is this unfair to QFs, it is inconsistent with PURPA and the FERC rules, which specify that QFs are supposed to be fully compensated for the capacity costs they enable utilities to avoid.

The unfairness of this approach is particularly evident in the case of existing solar QFs that invested in North Carolina on the understanding and expectation they would paid for the capacity they provide. It would clearly not be appropriate for Duke to continue to benefit from this capacity without providing fair payment for it. Yet, that would be the result of requiring them to renew their contracts using a seasonal allocation factor which assumes they will continue to provide this capacity but they will not be fairly compensated for it.

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

2 A. Yes.