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July 20, 2018

VIA ELECTRONIC FILING

M. Lynn Jarvis
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

Re: Application of Duke Energy Carolinas, LLC for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C. Gen. Stat. § 62-133.9 and NCUC Rule R8-69
Docket No. E-7, Sub 1164

Dear Ms. Jarvis:

On behalf of Duke Energy Carolinas, LLC ("DEC" or the "Company"), please find enclosed for filing the Company's Post-Hearing Brief.

The Post-Hearing Brief specifically addresses the Public Staff's proposal that the avoided capacity cost benefits for purposes of the Portfolio Performance Incentive and cost-effectiveness of the Company's demand-side management and energy efficiency programs be calculated under the assumption that capacity avoided prior to year 2023 be assigned a zero dollar value. DEC is also making a separate filing of its Proposed Order, which comprehensively addresses all issues raised in the above-referenced proceeding.

Please do not hesitate to contact me should you have any questions. Thank you for your assistance in this matter.

Sincerely,

Electronically submitted
s/ Molly McIntosh Jagannathan
molly.jagannathan@troutmansanders.com

Enclosure

Copy: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1164

In the Matter of Application by Duke Energy Carolinas, LLC for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C. Gen. Stat. §62-133.9 and Commission Rule R8-69	)))))))	**DUKE ENERGY CAROLINAS, LLC'S POST-HEARING BRIEF**

In this Post-Hearing Brief, applicant Duke Energy Carolinas, LLC ("DEC" or the "Company") submits its arguments in opposition to the Public Staff's recommendation that the avoided capacity cost benefits for purposes of the Portfolio Performance Incentive ("PPI") and cost-effectiveness of the Company's demand-side management ("DSM") and energy efficiency ("EE") programs be calculated under the assumption that capacity avoided prior to year 2023 be assigned a zero dollar value.[1] For the reasons set forth herein, the Public Staff's recommendation, as well as the resulting $8,994,251 reduction to DEC's Vintage 2019 PPI, should be rejected by the Commission.

I. BACKGROUND

Paragraphs 68 and 69 of the cost recovery mechanism approved by the Commission in Docket No. E-7, Sub 1032 ("Sub 1032 Mechanism") state as follows:

> 68. For the PPI for Vintage Year 2014, the per kW avoided capacity costs used to calculate avoided cost savings shall be those reflected in the filing by Duke Energy Carolinas in Docket No. E-100, Sub 136. The per kWh avoided energy costs shall be those reflected in or underlying the most recently filed integrated resource plan (IRP)...
>
> 69. For the PPI for Vintage Years 2015, 2016, and 2017, the presumptive per kW avoided capacity costs and per kWh

[1] All issues, whether contested or not, are addressed in the Company's Proposed Order. Terms and party names not otherwise defined herein are as stated in the Proposed Order.

> avoided energy costs used to calculate avoided cost savings shall be those determined pursuant to paragraph 68 above. However, if at the time of initial estimation of the PPI for each of those years, either (a) the Company's per kWh avoided energy costs calculated for the purposes of the Company's annual IRP or resource plan update filings have increased or decreased by 20% or more or (b) the Company's per kW avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings have increased or decreased by 15% or more, the avoided costs (both energy and capacity) will be updated for purposes of the DSM/EE rider proceeding.

The parties sometimes referred to the method for updating avoided costs under Paragraph 69 of the Sub 1032 Mechanism as the "trigger" or "ratchet" method, in that avoided costs would remain the same unless and until the specified thresholds were met – either a change in avoided energy costs of at least 20% or a change in avoided capacity costs of at least 15% – which would then trigger an update of both avoided energy and avoided capacity costs. In addition, under Paragraph 69 of the Sub 1032 Mechanism, avoided energy costs and avoided capacity costs were derived from two different sources: the annual IRP or resource plan update filings for avoided energy and the biennial avoided cost proceedings for avoided capacity.

In last year's DSM/EE proceeding in Docket No. E-7, Sub 1130 ("Sub 1130"), the Public Staff and DEC discovered that they had differing interpretations as to the appropriate avoided costs to be used in calculating Rider 9 pursuant to Paragraph 69 of the Sub 1032 Mechanism. The Public Staff believed that the "ratchet" that would cause avoided capacity and energy costs to be updated for purposes of the DSM/EE rider proceeding had been triggered for purposes of the PPI to be calculated for Vintage 2018. The Company maintained that the ratchet had not been triggered. Had avoided cost rates been updated in a manner consistent with the Public Staff's interpretation of Paragraph

69, the Vintage 2018 PPI would have been reduced by approximately $9.5 million.

The Company and the Public Staff eventually reached a comprehensive agreement (the "Sub 1130 Agreement" or "Agreement") resolving their differences which consisted of (1) a monetary adjustment which reduced the Vintage 2018 PPI by $6,750,000 million; and (2) certain revisions to the Sub 1032 Mechanism, including the method by which avoided costs would be updated for purposes of the PPI and DSM/EE program cost-effectiveness. The Commission approved the Sub 1130 Agreement and the resulting revisions to the Sub 1032 Mechanism in its *Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice* issued in Sub 1130 on August 23, 2017 ("Sub 1130 Order").

The revised Paragraph 69 reads as follows:

> 69. For the PPI for Vintage Years 2019 and afterwards, the program-specific per kW avoided capacity benefits and per kWh avoided energy benefits used for the initial estimate of the PPI and any PPI true-up will be derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing. However, for the calculation the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100 MW reduction typically used to represent a qualifying facility.

Paragraphs 19 and 23 (which govern the calculation of cost-effectiveness for program approval filings and continuing cost-effectiveness for existing programs, respectively) were also revised to reflect the same method for determining avoided costs.[2]

In the most recent Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities ("Avoided Cost Proceeding") in Docket No. E-100, Sub 148 ("Sub 148"), the Commission was faced with whether certain changes to the previously-approved methods used to calculate avoided cost rates and to the current framework for implementing Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") were warranted given the amount and pace of the development of qualifying facilities ("QFs"), and in particular solar-powered QFs, in North Carolina. *See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 148, October 11, 2017 ("Sub 148 Order"). The issue arose as to whether utilities should have to pay QFs for capacity in years in which they do not have a capacity need. Witnesses in the proceeding described significant growth in solar production in the State resulting in over-supply, operational challenges, and artificially high costs passed on to North Carolina residents, businesses, and industries. *Id*. at 9-14. DEC and Duke Energy Progress, LLC ("DEP") proposed, and a number of parties, including the Public Staff, agreed, that a utility should include zeros in the calculation of capacity rates for the years in which the utility does not have a capacity need. *Id*. at 39-41, 46.

While the case was pending, N.C. Gen. Stat. § 62-156(b)(3) was amended by the General Assembly in House Bill 589 to provide, with respect to power sales by small power producers to public utilities, as follows:

> A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource

[2] The Public Staff refers to the method for calculating avoided cost rates pursuant to the revised Paragraphs 19, 23, and 69 as the "PURPA method."

> plan filed with the Commission pursuant to G.S. 62-110.1(c) has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power, other than swine or poultry waste for which a need is established consistent with G.S. 62-133.8(e) and (f).

Accordingly, the Commission concluded that, with regard to QFs that are small power producers, § 62-156(b)(3) requires that when calculating avoided capacity rates using the peaker method, it is appropriate to require a payment for capacity in years of a utility's IRP forecast period only when a capacity need is demonstrated during that period. Sub 148 Order, p. 48. The Commission found that providing a levelized capacity payment over the term of the standard offer contract is a reasonable means of implementing this capacity payment. *Id*. The Commission also determined that this avoided capacity payment methodology is appropriate with regard to the standard offer to purchase available to QFs that are not small power producers. *Id*. The Commission based this change in methodology upon the "changed economic and regulatory circumstances facing QFs and utilities" – namely, the increasing amount of solar-powered QF development activity and its impact on utilities' systems and rates. *See id*. at 15-19, 48.

The underlying IRP for purposes of the Sub 148 proceeding – DEC's 2016 IRP – does not show a capacity need until 2023. *See id*. at 40. As such, the Commission's ruling in Sub 148 results in avoided capacity rates that use a zero value for capacity for the years 2019 to 2022. However, that ruling does not apply to QFs that established a legally enforceable obligation ("LEO") prior to the date the Company made its avoided cost filing in Sub 148. *See, e.g., Order Establishing Standard Rates and Contract Terms* *for Qualifying Facilities*, Docket No. E-100, Sub 136, issued Feb. 21, 2014, at 33 ("[a] QF has a right to long-term avoided cost contracts or other LEOs with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred."). As a result, QFs establishing a LEO after November 15, 2016 ("new QFs") receive a capacity value that is zero in 2019 through 2022;[3] QFs that established LEOs prior to November 15, 2016 ("legacy QFs") receive a capacity value that is not zero in 2019 through 2022. *See e.g.*, *Order Setting Avoided Cost Parameters*, Docket No. E-100, Sub 140, December 31, 2014 (Commission declines to approve utilities' request to not include the cost of capacity in years where the utility does not show a need for capacity when calculating avoided cost rates at that time).

In this proceeding, the parties agree that the applicable Avoided Cost Proceeding for Rider 10 is Sub 148. The key issue in dispute between the Company and the Public Staff is whether, because the Company does not show a capacity need until 2023, the Company is required by the Sub 1130 Agreement and the Sub 148 Order to use zero as the input when calculating its avoided capacity values for DSM/EE for years 2019 through 2022.

As described in the testimony of Public Staff witness Williams, the Public Staff interprets the Sub 1130 Order and the Sub 148 Order to mean that the Company's avoided capacity rates for DSM/EE should reflect zero avoided capacity value in years prior to the identified need for new capacity in the Company's IRP. (*See* Tr. at 216-17.)

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[3] New QFs under the standard offer tariff will receive capacity payments in years prior to the utilities' first capacity need because the new QFs will receive a levelized capacity rate reflecting a lower annual payment to account for those initial years in which there are no avoidable capacity costs. Sub 148 Order, pp. 40, 48.

Accordingly, witness Williams recommends that, for Vintage 2019 and afterward, as long as the Sub 148 avoided cost rates remain in effect, the avoided capacity cost benefits for purposes of the PPI and cost-effectiveness of the Company's DSM/EE programs be calculated under the assumption that capacity avoided prior to year 2023 be assigned a zero dollar value. (*See id*.) The Public Staff's recommendation would result in a decrease in the estimated Vintage 2019 PPI of $8,994,251. (*Id*. at 150.) It would also result in a decrease in cost-effectiveness scores for all of the Company's DSM/EE programs. (*Id*. at 183.)

The Company opposes the Public Staff's recommendation on the grounds that it is contrary to the intent of the Sub 1130 Agreement, that it erroneously treats legacy DSM/EE programs as new and incremental to the IRP, and that it conflicts with the public policy of the State of North Carolina. Accordingly, the Commission should reject the Public Staff's recommendation and approve the PPI and billing factors calculated by the Company in this proceeding.

II. ARGUMENT

A. The Public Staff's Position is Contrary to the Intent of the Sub 1130 Agreement.

"The heart of a contract is the intention of the parties, which is ascertained by the subject matter of the contract, the language used, the purpose sought, and the situation of the parties at the time." *Se. Caissons, LLC v. Choate Const. Co.*, 784 S.E.2d 650, 655 (N.C. Ct. App. 2016) (citing *Pike v. Wachovia Bank & Trust Co.*, 274 N.C. 1, 11 (1968) (citations omitted)). To ascertain intent, a court properly "consider[s] the language, subject matter and purpose of the contract, as well as the situation of the parties at the time, and may even read into a contract such implied provisions as may be necessary to effect the parties' intent." *Fed. Realty Inv. Trust v. Belk–Tyler*, 56 N.C. App. 363, 367 (1982); *see also Offiss, Inc. v. First Union Nat. Bank*, 150 N.C. App. 356, 363 (2002) (courts must consider "the expressed intent of the parties"); *N. Star Mgmt. of Am., LLC v. Sedlacek*, 235 N.C. App. 588, 592 (2014) (courts must "ascertain the intention of the parties at the moment of its execution").

Here, the Company's calculation of Rider 10 is consistent with the language and intent of the Sub 1130 Agreement. As witness Duff testified, the Sub 1130 Agreement was intended to eliminate the trigger method, so that avoided costs would be updated more frequently, and to change the source of avoided energy costs, so that avoided energy and avoided capacity rates for DSM/EE would be derived from the same proceeding. (Tr. at 308-09, 311.) The revisions to Paragraphs 19, 23, and 69 resulting from the Sub 1130 Agreement did not alter the source or manner in which the avoided capacity costs are to be derived for the purpose of calculating cost-effectiveness and incentives associated with DSM/EE programs. (*See id*. at 310-11; *see also* DEC's Response to Public Staff Data Request 22-2, Stevie/Duff Stipulated Ex. 8.) Accordingly, this year, the Company derived its proposed annual avoided capacity rate for DSM/EE as it always has – by dividing the annual capacity cost from the applicable Avoided Cost Proceeding (in this case, Sub 148) by the megawatt rating. (*See* Tr. at 310-11; *see also* DEC's Confidential Response to Public Staff Data Request 21-3,[4] Stevie/Duff Stipulated Ex. 7.) For DSM/EE programs already providing a capacity value underlying the resource plan used in Sub 148, the Company assumed that these resources would create a

[4] The Company has only included public information from this response in this Post-Hearing Brief.

value equivalent to the cost of building a new peaker – a method that has been used in all past DSM/EE filings. (*See* Tr. at 310-11; *see also* DEC's Response to Public Staff Data Request 22-1, Stevie/Duff Stipulated Ex. 8.) This starting point value of building a peaker was provided in Sub 148 in 2016 dollars, and that value was then escalated at the 2.5% rate, also approved in Sub 148. (*See* DEC's Response to Public Staff Data Request 22-1, Stevie/Duff Stipulated Ex. 8.)

Importantly, the avoided capacity rate used for DSM/EE and the avoided capacity rate paid to a QF are not identical. This was true under the Sub 1032 Mechanism, as well as under the revisions approved in Sub 1130. For example, the Sub 1032 Mechanism states that the per kW avoided capacity costs reflected in Avoided Cost Proceeding are "used to calculate avoided cost savings" for purposes of the PPI. The revised paragraphs of the Mechanism approved in Sub 1130 provide that the program-specific per kW avoided capacity benefits shall be "derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities." Stated another way, the avoided capacity cost reflected in the Avoided Cost Proceeding has always been an input to the calculation of avoided capacity benefits for purposes of DSM/EE but was never intended to be the same value. If the parties had intended for the avoided capacity rate the Company pays QFs to be equivalent to the avoided capacity rate calculated for DSM/EE, they would have said so – they did not. This much is clear from the plain language of the Mechanism.

Understanding that the avoided capacity rate reflected in the Avoided Cost Proceeding is merely an input to the DSM/EE avoided capacity calculation, we must look at the parties' intent to see whether they envisioned – at the time they entered into the Sub 1130 Agreement – for that input to be zero. The Commission may properly consider the parties' intent at the time of signing to interpret the Sub 1130 Agreement's express terms. *See Chapel Hill Spa Health Club, Inc. v. Goodman*, 90 N.C. App. 198, 203 (1988). For example, the North Carolina Court of Appeals found that price-discount discussions made at the time of signing a membership agreement were "in fact the basis for defendant's decision to join" and thus properly considered in determining the membership agreement's pricing. *Id*. Because both parties presented evidence of the membership agreement and the oral discussions, the appellate court determined that both were properly considered part of the "integrated transaction." *Id*. Here, both DEC and the Public Staff have presented evidence from the parties' discussions that shows the intent was to use capacity values that are not zero when determining the Company's avoided capacity cost of DSM/EE. These discussions were in fact the basis for the Company's decision to enter into the Sub 1130 Agreement and thus are properly considered by the Commission in determining the meaning of the Agreement.

As referenced in the Affidavit of Public Staff witness Maness, in Sub 1130, the Company provided the Public Staff with calculations showing that the projected PPI for 2018 would be reduced by approximately $9.5 million if the Public Staff's interpretation of the prior version of Paragraph 69 (i.e., that the triggers had been hit) had been applied to the calculation of the Vintage 2018 PPI. (Sub 1130 Tr. at 177.) The Company's position was that there should be no reduction to the Vintage 2018 PPI because the triggers had not been hit. (*Id*.) The monetary adjustment (reduction to the Vintage 2018 PPI) agreed to by the Public Staff and the Company in the Sub 1130 Agreement was $6,750,000. (*Id*. at 178.) When asked by counsel for NCSEA where this number came from, witness Maness testified that:

> in general, from the Public Staff's perspective, if paragraph 69 was taken to definitely apply to Vintage Year 2018, we felt that the proper interpretation would have be [sic] the approximately $9.5 million. There is a little bit of ambiguity in that paragraph 69 doesn't specifically mention Vintage 2018. *Also, in the course of our discussions with the Company, we began discussing switching to the, what we've termed the "PURPA method" and that would have resulted in a reduction of the PPI that would have been – I don't have the exact number but may be a little bit more than half of the difference between the Company's position and the reduction by the $9.5 million.* In our internal discussions and deliberations within the Public Staff, we felt the $6.75 million appropriately balanced all of the issues in the case between the PURPA method, the Public Staff's interpretation, and the Company's interpretation of paragraph 69, and we were satisfied that that was a reasonable conclusion and would be beneficial to the customers.

(*Id*. at 267-68 (emphasis added).)

In his Sub 1130 testimony, witness Maness specifically references a calculation of the resulting impact on PPI as calculated under the "PURPA method" – i.e., a determination of what the Vintage 2019 PPI would be if the Sub 1130 Agreement were approved by the Commission. *See id*. More importantly, he references the number resulting from this calculation being a key component of the compromise to reduce the Company's PPI by $6,750,000. *See id*.

This is corroborated by Company witness Duff. In his rebuttal testimony in this case, he explains that, as part of the exact same analysis the Company performed for the

Public Staff that produced the $9.5 million figure, the Company also provided a projection of what the change in Vintage 2019 PPI would be under the revisions to Paragraph 69 if the proposed avoided cost rates pending before the Commission in Sub 148 were approved. (Tr. at 314.) Specifically, the Company provided a projected stream of avoided capacity costs that reflected capacity values beginning in year one (2019). (*Id*. at 314-15.) The analysis provided clearly reflected avoided capacity values in the years 2019 through 2022, rather than the zero value now advocated by the Public Staff. (*Id*. at 315.)

Testimony from both the Company and the Public Staff demonstrates that the Public Staff knew at the time that it entered into the Sub 1130 Agreement that the Company did not intend to apply zero values for capacity for the Vintage 2019 PPI and that the monetary adjustment the parties agreed to as part of the Sub 1130 Agreement was based on analysis that did not include zeros for capacity. This could mean one of two things: (1) that the Public Staff shared the Company's intent that zeros should not be applied for capacity for DSM/EE, or (2) that the Public Staff knew it was the Company's intent that zeros should not be applied for capacity, disagreed, but failed to challenge the assumption upon which this analysis was based.[5]

As the Company stated in response to a Public Staff data request, "Since this analysis was relied upon in the development of the agreed-upon reduction to the 2018 PPI in Docket E-7, Sub 1130 (as acknowledged in Witness Maness' testimony at the Sub

[5] The Public Staff's position was a $9.5 million reduction, the Company's position was a $0 reduction, and as witness Maness testified, the figure the Company calculated using the method described in revised Paragraph 69 was somewhere in between. Had the Company used zeros for capacity in applying the revised Paragraph 69, the number would have been substantially lower, and thus the reduction to the Vintage 2018 PPI that the Company would have been willing to agree to as a compromise would have been correspondingly smaller.

1130 hearing) and the Public Staff never expressed disagreement with the analysis, the Company believes that its intent was clear and was surprised that the Public Staff would take the position that zeros should be used for avoided capacity when this analysis did not utilize zeros for avoided capacity for the Vintage 2019 PPI."[6] (Response to Public Staff Data Request 22-4, Stevie/Duff Stipulated Ex. 8.)

Further evidence that the Public Staff shared – or at least was aware of – the Company's intent, is the Public Staff's recommendation of approval of the addition of the "Bring Your Own Thermostat" ("BYOT") measure to the Company's Power Manager Program. The Company filed this program modification on December 28, 2017, after both the Sub 1130 Order and Sub 148 Order had been issued and House Bill 589 had gone into effect. (*See* DEC's Proposed Modifications to the Power Manager Load Control Service - Rider PM, Docket No. E-7, Sub 1032, December 28, 2017 ("BYOT Application").) Revised Paragraph 19 provides that for program approval filings, like the BYOT Application, the Company shall use the same method as prescribed by revised Paragraph 69, with the avoided capacity and energy benefits derived from the most recent Commission-approved Avoided Cost Proceeding as of the date of the filing for approval. Accordingly, the Company applied this method utilizing avoided cost rates derived from the avoided capacity credits reflected in the Sub 148 Avoided Cost Proceeding to

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[6] The Public Staff included a caveat to the Sub 1130 Agreement that the Public Staff would be able to propose further revisions to the Mechanism should the methodologies adopted in an Avoided Cost Proceeding change in a manner that conflicts with their use in the DSM/EE context. (Sub 1130 Tr. at 180-81.) The Public Staff was particularly concerned with impact that adoption of the "two-year refresh" proposal by the Company would have on the method for calculating avoided energy costs pursuant to the Sub 1130 Agreement. (*See id.*) As discussed below, the two-year refresh proposal was rejected by the Commission in the Sub 148 Order, so this caveat did not come into play in this proceeding. Nevertheless, it serves as further evidence that the Company was confident that the Public Staff shared its intent, as the Company did not see any need to caveat the Agreement in like manner (though, as explained further below, the adoption of a zero capacity value clearly would conflict with the use of avoided costs from the Sub 148 proceeding in the DSM/EE context).

determine the cost-effectiveness of Power Manager with the addition of BYOT. (*See* BYOT Application.) Significantly, the Company included capacity values that were *not* zero in its filing. (*See id*., Attachment A, lines 40-43; Attachment B, line 3.[7]) In fact, since Power Manager is a DSM measure, there are no avoided energy benefits – only avoided capacity and avoided transmission and distribution ("T&D") – as clearly shown on Attachments A (*see* lines 40-49) and B (*see* line 3).

There is no question that the Public Staff examined the cost-effectiveness evaluations the Company provided in its 17-page BYOT Application. As the Commission stated in its February 7, 2018 *Order Approving Program Modifications*, the Company's "application includes estimates of the Program's impacts, costs, and benefits used to calculate the cost-effectiveness of the Program. DEC's calculations indicate that the Program will remain cost-effective under the Total Resource Cost, the Utility Cost, and the Rate Impact Measure tests." The Public Staff recommended that the Commission approve the BYOT modification to the Power Manager program, stating that "the Program has the potential to continue to encourage energy efficiency, appears to continue to be cost effective, will be included in future DEC IRPs, and is in the public interest." (*Id*.)

The Company has clear and consistent evidence of its intent and the Public Staff's knowledge of its intent. By contrast, the only witness in this proceeding testifying about the Public Staff's intent – witness Williams – was absent from the Sub 1130 discussions. Though he testified at length regarding the reasons that the Company and the Public Staff chose to propose revisions to the Sub 1032 Mechanism regarding the source of the

[7] Attachments A and B to the BYOT Application are attached hereto as Exhibits A and B, respectively).

avoided energy and capacity, his "Qualifications and Experience" show that he was not employed by the Public Staff when DEC and the Public Staff negotiated and consummated the Sub 1130 Agreement and, therefore, did not participate in any of the discussions leading up to the agreement. (*See* Tr. at 230; *see also* Public Staff's Response to DEC Data Request 1-13, Stevie/Duff Stipulated Ex. 6.) In short, the only evidence that the Public Staff presented relating to the intent of the agreement was from a witness who has no first-hand knowledge thereof.

While witness Williams cites witness Hinton's testimony in Sub 1130 ostensibly as evidence that the Public Staff's position is consistent with the letter and intent of the Sub 1130 Agreement,[8] witness Hinton merely testified that the use of PURPA-based avoided costs (which, as mentioned above, the Company has always used for avoided capacity) links the Company's DSM/EE savings and financial incentives with the avoided cost rates it pays QFs. (*Id.* at 220-21; *see also* Sub 1130 Tr. at 250-51.) This is not a groundbreaking proposition, and, indeed, the Company agrees with witness Hinton – because the avoided costs for DSM/EE programs are derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the Avoided Cost Proceeding, they are, in fact,

[8] Witness Williams inexplicably cites witness Duff's Sub 1130 testimony as also being consistent with the Public Staff's position – it is not. Witness Williams selectively quotes Mr. Duff's testimony to create the illusion that Mr. Duff testified that the revisions to the Mechanism resulting from the Sub 1130 Agreement were designed to align avoided capacity costs for DSM/EE with those paid QFs. (*See* Tr. at 218.) Mr. Duff said nothing of the sort. As he pointed out in his rebuttal testimony in this proceeding, witness Duff's testimony in Sub 1130 clearly referred to the fact that the proposed revisions align avoided energy costs *for DSM/EE* with avoided capacity costs *for DSM/EE*. (Sub 1130 Tr. at 65-66.) The inconsistent assumptions to which he referred were that the avoided energy cost for DSM/EE previously had been derived from the IRP proceeding, whereas the avoided capacity cost for DSM/EE had been derived from the Avoided Cost Proceeding. *See id*. The Company also pointed this out in response to a data request prior to witness Williams filing this misleading testimony. (DEC's Response to Public Staff Data Request 16-1, Stevie/Duff Stipulated Ex. 3.)

linked to (but not the same as) the avoided cost rates the Company pays QFs. This was the case under the Sub 1032 Mechanism and is the case under the Sub 1130 revisions.

The Public Staff then extrapolates that because avoided costs for DSM/EE are linked to those paid to QFs, the avoided cost rates for capacity that are used in the calculation of ongoing cost-effectiveness and utility incentives for DSM/EE programs should be consistent with the avoided cost rates for capacity for new QFs. (Tr. at 216-17.) However, as discussed below, existing DSM/EE programs are much more analogous to legacy QFs, which receive a capacity value that is not zero in years 2019 through 2022. It is therefore appropriate for the Company to use the forecasted avoided capacity costs that recognize the value of the legacy DSM/EE resources in each year underlying the Company's resource plan.

B. The Public Staff's Approach is Inappropriate and Underestimates the Value of the Company's DSM/EE Programs.

The Public Staff's position is based on the fallacy that all of the Company's DSM/EE programs are "new" and incremental to the IRP. This presumption is not only untrue, but seriously undervalues the Company's DSM/EE programs.

Witness Williams posits that because, as long as the Sub 148 Order is in effect, new QFs seeking to sell their energy and capacity to DEC will not be paid capacity payments until new capacity is needed, "incentives of both new DSM/EE programs and new vintages of existing DSM/EE programs starting in vintage 2019 should be based on avoided capacity rates that reflect zero avoided capacity value in years prior to the identified need for new capacity in the Company's IRP." (Tr. at 216-17.) This position is flawed for several reasons.

To begin with, witness Williams inappropriately defines "new" to include "new vintages of existing DSM/EE programs," which necessarily includes every single one of the Company's DSM/EE programs regardless of when they were established and whether they were included in the IRP. (*See* Tr. at 217.) Based upon this position, the Public Staff removes the avoided capacity value for *all* of the DSM/EE kW impacts in the years 2019 to 2020. (*See id*. at 318.) As shown in the 2016 DEC IRP, in 2019 this represents the removal of the capacity value for 1,119 MW of DSM impacts and 220 MW of EE impacts of summer capability from the Company's existing portfolio of approved DSM/EE programs. (*Id*.)

In relying on this faulty definition, the Public Staff has completely ignored the legacy aspect of the Company's DSM programs. The DSM programs are not incremental programs. (*Id*.) They are not "new." (*Id*.) Even the Public Staff's witnesses concede that the DSM programs included in the IRP block are stable and expected to continue for the foreseeable future. (*See id*. at 227.) As DEC witness Stevie stated, these are established programs that are treated as a dispatchable resource in the Company's IRP. (*Id*. at 319, 323.)

Moreover, witness Williams' own analysis demonstrated that the existing DSM resources provide real value in terms of capacity during the 2019 to 2022 timeframe. (*Id*. at 224-26, 319.) In his testimony, he states that by year 2022, 95% of the DSM programs would be needed to defer the need for capacity to the year 2023. (*Id*. at 225.) He also acknowledges that the DSM programs are necessary in 2019 and 2020 to avoid building new capacity. (*Id*. at 225-26.) Indeed, if the Company's legacy DSM programs were closed tomorrow, there would be an immediate need for new capacity. (*Id*. at 319.) It thus defies logic for a resource such as the legacy DSM programs not to receive a capacity valuation. Nevertheless, the Public Staff's position is that the Company should use zero capacity value for all DSM/EE programs – even those which the Public Staff acknowledges are providing necessary capacity for the Company to reliably serve its customers.

The Company believes it is appropriate to recognize the similarity between the continuing capacity value for these legacy DSM programs and QFs that had established LEOs or had signed power purchase agreements with the Company prior to November 15, 2016. These legacy QFs are now receiving long-term fixed rates (up to 15 years) that included capacity values in every year based on the Commission's policies and avoided cost orders in effect prior to House Bill 589's enactment. (Tr. at 320.) No party has recommended a retroactive revision of existing purchase power agreements (some of which may continue until 2030 or longer under Section I.(c) of House Bill 589) entered into by the Company and these legacy QFs that contracted to sell prior to November 15, 2016 to modify the capacity payments to reflect the Commission's Sub 148 Order. (*Id.*) Likewise, the Company should be compensated for its legacy DSM programs based upon the avoided cost framework in existence at the time of Commission approval. Accordingly, the Company's legacy DSM programs, which are, in fact, providing capacity value in the near-term to avoid future capacity needs, deserve to be assigned an avoided capacity value similar to the legacy QFs and not to have the zero value position of the Public Staff retroactively imposed upon them.

The Company's My Home Energy Report ("MyHER") EE program is effectively in the same position as the legacy DSM programs. The MW capability provided by the

MyHER EE program was created in the past, prior to the establishment of the new avoided cost rates. (*Id*. at 321.) All that is required is the expenditure of funds to maintain the impacts, just like the Company must do to maintain the availability of the impacts from the legacy DSM programs. (*Id*.) In this case, the MyHER program impacts are also not incremental or new after November 2016. (*Id*. at 321-22.) They are embedded in the resource plan, and like legacy QFs with LEOs existing prior to November 15, 2016, should receive a capacity value in the 2019 to 2022 time period. (*Id*. at 322.)

The Company acknowledges that its other EE programs aside from MyHER are, in some respects, different than the DSM programs in that most represent incremental new impacts in the resource plan. (*Id*. at 321.) However, the Company's inputs to the IRP for the cost of the DSM and EE programs include not just the implementation cost, but also the estimate of the utility's PPI, which contains a capacity value for the years 2019 through 2022. (*Id*. at 323.) As a result, to be consistent with the underlying resource plan, including the cost inputs, it makes sense to include the avoided capacity value of these EE programs as well for the years 2019 to 2022. (*Id*.)

Further, there is a summer capacity need of 425 MW (379 MW for the winter) from the EE programs in the year 2023.[9] (*Id*. at 322.) As witness Stevie pointed out, "anyone who has been around the implementation of EE programs for any length of time will recognize that one does not create 425 MW of EE overnight. It takes time. It takes time to build customer awareness. It takes time for equipment to wear out and be replaced or for customers to recognize that it is time to change out equipment." (*Id*.) In

[9] These figures do not include the MW impacts of the MyHER program.

other words, DEC cannot flip a switch and turn an EE program on or off. While the Public Staff would not likely advocate for the Company to shut down its existing EE programs during "gap years" until a capacity need arrives, from a financial perspective, it is effectively telling them to do just that.

In sum, it is clear that the legacy DSM programs and the MyHER program deserve a capacity value that is not zero for the years 2019 to 2022 and beyond. The legacy DSM programs are not incremental and are treated as a dispatchable resource in the IRP. In addition, even the Public Staff's own analysis concluded that the legacy DSM programs provide a capacity value during the 2019 to 2022 time period. With respect to the MyHER EE program, because its load impacts are also not incremental and existed prior to the treated establishment of the new avoided cost rates, they also deserve a capacity value that is not zero. Finally, in order to be consistent with the underlying resource plan and the public policy discussed further below, the Commission should also include the avoided capacity value for all of the Company's remaining EE programs for the years 2019 to 2022.[10]

C. The Public Staff's Position is Inconsistent with the Public Policy of the State of North Carolina.

Witness Williams' testimony implies that DSM/EE is the first capacity resource that should be cut out of the Company's resource plan in the event DEC's IRP does not show a need for capacity. (*See* Tr. at 224-27.) Similarly, by urging the Commission to

[10] For the Company's approved EE programs other than MyHER, the Company believes it valued them appropriately with an avoided capacity value that is not zero for all years for the reasons discussed above. However, should the Commission decide that these programs should be treated differently than the legacy DSM programs and MyHER, then the Company would recognize that the incremental impacts from those programs could be treated the same as the incremental new QF resources in the IRP. This means that, consistent with how "new" QFs with LEOs after November 15, 2016 are treated, the Company would ascribe a zero value of capacity for the years 2019 to 2022 for these other EE programs.

adopt zero avoided capacity values for DSM/EE, the Public Staff seeks to remove the financial incentive for the Company to pursue certain programs in years 2019 to 2022, and effectively sends the Company the message that it is not worth it to encourage customers to find ways to reduce their kW impact.

In addition, as witness Williamson acknowledges, as avoided cost rates decrease, it becomes difficult for a DSM/EE program to produce cost-effective savings. (Tr. at 183.) Indeed, for Vintage 2019, application of the Public Staff's position would result in two of the Company's existing programs crossing the threshold from cost-effective to not cost-effective. (*Id*. at 186-88.) This trend is sure to continue if zero capacity values continue to be applied through 2022. Given the ramp up time required to engage customers and build participation in DSM/EE programs, if the Company's programs are canceled due to failing cost-effectiveness (in this case, due solely to the application of zero capacity values), it would be extremely difficult to resurrect them once cost-effectiveness is restored. For example, if the Public Staff's position were adopted by the Commission and DEC were forced to shut down a DSM or EE program in 2019 due to deteriorating cost-effectiveness, the Company would have to dismantle the program and tell participants they no longer would receive incentives. It is unlikely that these same customers would choose to participate again if the program were brought back in 2023, and the Company would lose this pool of participants.

Ultimately, what the Public Staff's argument fails to acknowledge is that DSM and EE programs are a desirable resource that is not only encouraged but mandated by the State. Senate Bill 3 was passed in August 2007 "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable

Energy and Energy Efficiency Portfolio Standard (REPS)." N.C. Gen. Stat. § 62-2(10). The stated goals of the legislation are to diversify the resources used to reliably meet the energy needs of consumers in the State, provide greater energy security through the use of indigenous energy resources available within the State, encourage private investment in renewable energy and EE, and provide improved air quality and other benefits to energy consumers and citizens of the State. *Id*. To this end, Senate Bill 3 provides that electric utilities "shall implement demand-side management and energy efficiency measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of its customers." *See* N.C. Gen. Stat. § 62-133.9. Through the enactment of REPS, Senate Bill 3 also requires each electric public utility in the State to meet increasing percentages of its energy needs each year through EE measures. *See* N.C. Gen. Stat. § 62-133.8. Finally, this legislation provides that the utilities shall be compensated for their DSM/EE efforts and allows incentives to be awarded, including rewards based upon shared savings and avoided costs achieved by DSM/EE measures. *See* N.C. Gen. Stat. § 62-133.9.

Apart from Senate Bill 3, the Public Utilities Act more broadly promotes the establishment of "just and reasonable rates…consistent with long-term management and conservation of energy resources by avoiding wasteful, uneconomic and inefficient uses of energy" and encourages "harmony between public utilities, their users and the environment." *See* N.C. Gen. Stat. § 62-2(4) and (5). In addition, the Act provides that it is the public policy of the State of North Carolina to:

> To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options,

> including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to 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, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills[.]

N.C. Gen. Stat. § 62-2(3a). Through Senate Bill 3 and the stated policy of the Public Utilities Act, it is apparent the legislature not only appreciates the importance of energy efficiency, but also recognizes that if a utility is not appropriately compensated and incentivized for its DSM/EE efforts (which, from a financial perspective, equate to a utility spending money to encourage its customers to buy less of its product), it is difficult to put these efforts on equal footing with supply-side resources, for which the Company receives a return. As the Company indicated in its response to a Public Staff data request:

> When the Company implements DSM/EE programs, it is delaying the need to build new power plants. Delaying or eliminating the need to build new capacity impacts the expected future earnings for the Company. To remove the financial disincentive associated with the pursuit of DSM/EE, it makes sense to provide the utility with a financial reward similar to that associated with the earnings on a power plant. In other words, in order to further the policy purpose of encouraging utilities to pursue energy efficiency, financial incentives are designed to make the utility essentially indifferent from a financial standpoint with respect to implementing DSM/EE programs versus building a new plant. If the incentive is reduced, that violates that regulatory compact.

(DEC's Response to Public Staff Data Request 21-2, Stevie/Duff Stipulated Ex. No. 7.)

Of course, the policies discussed above do not give the Company free reign to implement – and recover incentives for – any DSM and EE programs it chooses to offer without regard to cost to customers. In accordance with the statutory framework outlined above, through its IRP process, the Company has developed a least cost mix of resources which includes a defined block of cost-effective DSM/EE measures. Unlike natural gas units, solar facilities, or other supply-side options, DSM/EE MW impacts depend on forecasts of customer adoption for each individual DSM/EE measure and program. (DEC's Response to Public Staff Data Request 14-3, Stevie/Duff Stipulated Ex. 2.) Long-term adoption rate estimates are shown at technical potential, economic potential, and achievable potential levels as represented in periodically updated "Market Potential Studies." (*Id*.) Shorter term projections of MW impacts come from forecasted adoption rates from existing Commission-approved DSM/EE programs based on the experience of program managers and evaluation, measurement, and verification (EM&V). (*Id*.) It is this combination of short-term projections for existing programs and longer term achievable potential that, when combined, produce the MW and MWh reduction in the retail load forecast due to utility-sponsored DSM/EE. (*Id*.) DSM/EE programs also have separate cost-effectiveness metrics, including the Total Resource Cost (TRC) test, the Utility Cost Test (UCT), the Participant Test, and the Ratepayer Impact Measure (RIM) test. (*See id*.; *see also* Tr. at 180.) Only approved cost-effective programs reduce the retail load that goes into the IRP. (DEC's Response to Public Staff Data Request 14-3, Stevie/Duff Stipulated Ex. 2.) Public Staff witness Williams has dismissed the block of DSM/EE measures the Company has included in its IRP as "fluid" and treats them as dispensable (*see* Tr. at 223), but these are real programs that create real savings. These savings, in turn, offset the Company's need to build new generation, and the Company should be appropriately incentivized to implement these programs.

It makes sense for customers not to have to pay for third parties to supply generation capacity that the Company does not need – that is the crux of N.C. Gen. Stat. § 62-156 and the Sub 148 Order. However, it is far different to encourage customers to use less energy and capacity to decrease their bills. And as dictated by the State of North Carolina, this should be encouraged and reflected in the Company's rates through "consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills." By eliminating avoided capacity benefits from the Company's incentive, the Public Staff is removing that reward.

Witness Williams repeatedly cites N.C. Gen. Stat. § 62-156 to support his argument that the Company should receive zero capacity values for DSM/EE. However, this statute, by its terms, is limited to small power producers. Nevertheless, witness Williams conclusively states that the General Assembly and Commission have determined that customers should not have to pay for capacity the Company does not need and characterizes this as a general principle that necessarily includes DSM/EE. If the General Assembly had intended for DSM/EE to be included in this provision of House Bill 589, it certainly could have done so, but did not. In any event, as discussed above, in the case of DSM/EE, customers are not paying for capacity they do not need.

Similarly, if the Commission had intended for DSM/EE to receive zeros, it would have said so in the Sub 148 Order. However, nowhere in the Commission's discussion of either the changed circumstances warranting the change in avoided cost methodology (Finding of Fact No. 1) nor in its discussion of the adoption of the approach that new QFs should not receive payments for capacity in years in which there is no capacity need (Finding of Fact Nos. 5 and 6), does the Commission mention DSM/EE. *See* Sub 148

Order, pp. 9-19, 39-50. In fact, DSM/EE is only mentioned once in the entire Sub 148 Order (Finding of Fact No. 10), and in a manner that is irrelevant to the issue at hand.[11] *Id*. at 69. While witness Williams contends that the Sub 148 Order, in effect, commands that DSM/EE should receive zero capacity value, nothing in the Commission's order dictates this result.

When one looks beyond the selectively quoted passages of the Sub 148 Order in

[11] Witness Williams asserts that the Commission has determined that customers should not have to pay for capacity that the Company does not need and that new QFs should receive the equivalent of zero avoided capacity cost payments until capacity is needed. (*See* Tr. at 222.) In the very next sentence, he states "As the Commission noted, '…the Commission-determined avoided costs are utilized in, among other applications, the determinations of the ongoing cost-effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs…'" (*Id*. (citing Sub 148 Order, p. 69).) However, witness Williams takes the quoted material out of context (it is from an entirely different section of the Sub 148 Order) and erroneously links it to the concept that QFs should receive zero avoided capacity payments – the Commission's Sub 148 Order does no such thing.

The full paragraph that was excerpted from by witness Williams reads as follows:

> The Commission notes that in addition to providing the basis for electric power purchases from QFs by a utility, the Commission-determined avoided costs are utilized in, among other applications, the determination of the cost effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs, the determination of the incremental costs of compliance with REPS for cost recovery purposes; and in some ratemaking, such as determination of stand-by rates. In these contexts, it is appropriate for the rates to be reflective of the utilities' actual forecasted rates over a longer term, not based on a short-term forecast that is fixed for the duration of a longer term."

Sub 148 Order, p. 69.

While the paragraph does reference that Commission-determined avoided costs are utilized in "the determination of the cost effectiveness of DSM/EE programs and the calculation of the performance incentives" (a concept which no party disputes), it in no way indicates that they are to be utilized in a manner consistent with the Public Staff's position. *See id*. The portion of the Sub 148 Order that contains this paragraph is specifically dealing with Finding of Fact No. 10, which does not deal with avoided capacity rates, but rather with the Commission's denial of DEC and DEP's request to reset energy rates utilized in a standard contract every two years. *See id*. at 61-70. That the Commission mentions DSM/EE in the section of its order dealing with the "two-year refresh," makes sense because several months prior, the Public Staff had expressly noted its concern about the impact of the two-year refresh of avoided energy rates on DSM/EE to the Commission, and even incorporated its concern as a caveat to the Sub 1130 Agreement. (Sub 1130 Tr. at 180-81.)

While the language referenced clearly indicates the Commission believes that because the avoided energy rates are utilized in calculations associated with cost-effectiveness and performance incentives related to DSM/EE programs, they should not be updated every two years, it is a far cry from supporting the Public Staff's contention related the application of avoided capacity rates.

witness Williams' testimony, it becomes very clear that the driver for the Commission's decision was the growth in solar. In finding that the economic and regulatory circumstances facing QFs and utilities have changed since the previous Avoided Cost Proceeding, the Commission cited substantial evidence relating to the sheer volume of solar QF development, as well as testimony that the significant growth of facilities from which utilities are obligated to purchase energy and capacity has increased the risk of potential overpayment by ratepayers. *See* Sub 148 Order, pp. 9-19. For example, the Commission relied upon testimony from Company witness Yates that North Carolina's marketplace for solar is "distorted," which results in artificially high costs being passed on to North Carolina ratepayers. *Id*. at 16. The Commission further found that the increasing amount of solar-powered QFs interconnected to DEC's electric systems is "inhibiting the Companies' ability to fulfill its public service mission and statutory obligation to provide safe and reliable energy to its customers at reasonable rates." *Id*. The Commission also cited testimony from witness Hinton that the pace of QF solar development is now exceeding the growth experienced by the utilities. *Id*. at 13. Witness Hinton also explained that this higher penetration of solar QF resources is posing operational and technical challenges for the utilities in meeting their obligation to provide safe, reliable, and economic service. *Id*. The Commission agreed that the implications of the pace and level of QF development continuing unabated poses serious risk of overpayment by utility ratepayers and operational soundness of utility electric systems, and, ultimately, calls in to question the State's continued compliance with PURPA's requirements. *Id*. at 15.

With respect to the Company and DEP's proposal regarding the use of zero capacity value for QF payments in years in which the IRP does not show a capacity need, witness Hinton testified that contrary to the position taken by the Public Staff in prior proceedings, "he believed that *in light of current circumstances related to the amount of solar generation online and pending in the interconnection queue*, it is appropriate for the utilities to adjust their avoided cost rates to provide a capacity payment to new QFs only when additional capacity is needed on the system." *Id*. at 46 (emphasis added). The Commission again agreed with witness Hinton, finding that including a capacity credit only in those years in which the IRP has established a capacity deficiency sends a better price signal to the solar market. *Id*. at 49.

Finally, in concluding that QFs should only receive capacity payments in years in which the utility has a capacity need, the Commission noted that the operating characteristics of a QF resource must be considered in evaluating whether a QF resource can help to avoid the utility's planned capacity addition. *Id*. In considering these characteristics and other factors, the Commission concluded that the capacity value provided by additional solar PV does not necessarily help the utilities offset or avoid their next capacity need. *Id*. The Commission encouraged utilities to focus on improving rate design to ensure that the change in policies adopted in the Sub 148 Order does not adversely impact other small power producers for "problems that are specifically related to solar energy." *Id*. at 49-50.

DSM/EE by its very nature is different from a solar QF, and none of the policy reasons behind the Commission's shift in avoided costs methodology articulated in the Sub 148 Order apply to DSM/EE. There is no evidence in this proceeding that there is an over-supply of DSM/EE programs, that customers are paying artificially high prices for

DSM/EE, or that DSM/EE is burdening the system. There is no showing of an overabundance of DSM/EE programs such that the Commission needs to send a price signal to the Company to cut back on its DSM/EE programs. In addition, as discussed several times herein, in evaluating the characteristics of DSM/EE resource, it is clear that DSM/EE can help to avoid planned capacity additions. In sum, there is a fundamental difference between what the Commission and General Assembly were trying to avoid – customers paying for capacity in the form of additional generation that the Company does not need – and the Company's implementation of DSM/EE programs to encourage customers to use less energy and capacity in accordance with the policy of the State of North Carolina as expressed in Senate Bill 3 and elsewhere in the Public Utilities Act.

III. CONCLUSION

For the reasons set forth above, DEC respectfully requests that the Commission: (1) reject the Public Staff's recommendation that determinations of the Company's PPI and cost-effectiveness of its DSM/EE programs should be based on avoided capacity rates that reflect zero avoided capacity value in years prior to the identified need for new capacity in the Company's IRP; (2) deny the Public Staff's downward adjustment to the Vintage 2019 PPI; (3) accept the cost-effectiveness calculations performed by the Company for purposes of Rider 10; and (4) approve the Company's calculation of the DSM/EE rates for Vintage 2019, as reflected in the rebuttal testimony and exhibits of DEC witness Miller.

Respectfully submitted this 20th day of July, 2018.

/s/ Molly McIntosh Jagannathan

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ATTORNEYS FOR DUKE ENERGY CAROLINAS, LLC

Attachment A
Participation

Bring Your Own Thermostat / Power Manager		
1	Measure Life (Average)	1
2	Free Rider % (Average)	0%
3	Incremental Participants Year 1	19,807
4	Incremental Participants Year 2	50,764
5	Incremental Participants Year 3	80,210
6	Incremental Participants Year 4	109,371
7	Incremental Participants Year 5	143,100
8	Cumulative Participation Year 1	19,807
9	Cumulative Participation Year 2	50,764
10	Cumulative Participation Year 3	80,210
11	Cumulative Participation Year 4	109,371
12	Cumulative Participation Year 5	143,100
13	Cumulative Summer Coincident kW w/ losses (net free) Year 1	34,496
14	Cumulative Summer Coincident kW w/ losses (net free) Year 2	75,884
15	Cumulative Summer Coincident kW w/ losses (net free) Year 3	114,927
16	Cumulative Summer Coincident kW w/ losses (net free) Year 4	153,095
17	Cumulative Summer Coincident kW w/ losses (net free) Year 5	195,184
18	Cumulative kWh w/ losses (net free) Year 1	0
19	Cumulative kWh w/ losses (net free) Year 2	0
20	Cumulative kWh w/ losses (net free) Year 3	0
21	Cumulative kWh w/ losses (net free) Year 4	0
22	Cumulative kWh w/ losses (net free) Year 5	0
23	Per Participant Weighted Average Coincident Saved Winter kW w/ losses	0.00
24	Per Participant Weighted Average Coincident Saved Summer kW w/ losses	1.74
25	Per Participant Average Annual kWh w/ losses (net free) Year 1	0
26	Per Participant Average Annual kWh w/ losses (net free) Year 2	0
27	Per Participant Average Annual kWh w/ losses (net free) Year 3	0
28	Per Participant Average Annual kWh w/ losses (net free) Year 4	0
29	Per Participant Average Annual kWh w/ losses (net free) Year 5	0
30	Cumulative Lost Revenue (net free) Year 1	$0
31	Cumulative Lost Revenue (net free) Year 2	$0
32	Cumulative Lost Revenue (net free) Year 3	$0
33	Cumulative Lost Revenue (net free) Year 4	$0
34	Cumulative Lost Revenue (net free) Year 5	$0
35	Average Lost Revenue per Participant (net free) Year 1	$0
36	Average Lost Revenue per Participant (net free) Year 2	$0
37	Average Lost Revenue per Participant (net free) Year 3	$0
38	Average Lost Revenue per Participant (net free) Year 4	$0
39	Average Lost Revenue per Participant (net free) Year 5	$0
40	Total Avoided Costs/MW saved Year 1	$124,204
41	Total Avoided Costs/MW saved Year 2	$126,491
42	Total Avoided Costs/MW saved Year 3	$129,323
43	Total Avoided Costs/MW saved Year 4	$132,414
44	Total Avoided Costs/MW saved Year 5	$135,627
45	Total Avoided Costs/MWh saved Year 1	N/A
46	Total Avoided Costs/MWh saved Year 2	N/A
47	Total Avoided Costs/MWh saved Year 3	N/A
48	Total Avoided Costs/MWh saved Year 4	N/A
49	Total Avoided Costs/MWh saved Year 5	N/A

Bring Your Own Thermostat / Power Manager

Attachment B
Cost-Effectiveness Evaluation

	Bring Your Own Thermostat / Power Manager				
		UCT	**TRC**	**RIM**	**Participant**
1	Avoided T&D Electric	$76,973,205	$76,973,205	$76,973,205	$0
2	Cost-Based Avoided Elec Production	$0	$0	$0	$0
3	Cost-Based Avoided Elec Capacity	$86,503,379	$86,503,379	$86,503,379	$0
4	Participant Elec Bill Savings (gross)	$0	$0	$0	$0
5	Net Lost Revenue Net Fuel	$0	$0	$0	$0
6	Administration Costs	$6,943,644	$6,943,644	$6,943,644	$0
7	Implementation Costs	$36,751,523	$36,751,523	$36,751,523	$0
8	Incentives	$22,812,488	$0	$22,812,488	$22,812,488
9	Other Utility Costs	$2,935,047	$2,935,047	$2,935,047	$0
10	Participant Costs	$0	$0	$0	$0
11	Total Benefits	$163,476,584	$163,476,584	$163,476,584	$22,812,488
12	Total Costs	$69,442,702	$46,630,214	$69,442,702	$0
13	**Benefit/Cost Ratios**	**2.35**	**3.51**	**2.35**	

Data represents present value of costs and benefits over the life of the program.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing POST-HEARING BRIEF OF DUKE ENERGY CAROLINAS, LLC upon each of the parties of record in this proceeding or their attorneys of record by deposit in the U.S. Mail, postage prepaid or by email transmission with the party's consent.

This 20th day of July, 2018.

/s/ Molly McIntosh Jagannathan

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