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August 13, 2020

VIA ELECTRONIC FILING

Kimberley A. Campbell
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Duke Energy Carolinas, LLC's Post-Hearing Brief
Docket No. E-7, Sub 1230

Dear Ms. Campbell:

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

DEC is also making a separate filing of its Proposed Order, which comprehensively addresses all issues raised in the above-referenced proceeding. An electronic copy is being emailed to briefs@ncuc.net.

Please do not hesitate to contact me should you have any questions or need additional information.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosure

cc: Parties of Record

<u>CERTIFICATE OF SERVICE</u>

I certify that a copy of Duke Energy Carolinas, LLC's Post-Hearing Brief, in Docket No. E-7, Sub 1230, has been served on all parties of record either by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid.

This the 13th day of August, 2020.

Kendrick C. Fentress

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1230

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 recommendation of the Public Staff of the North Carolina Utilities Commission ("Public Staff") that the avoided capacity cost benefits for purposes of the Portfolio Performance Incentive ("PPI") and cost-effectiveness of the Company's legacy, pre-existing demand-side management ("DSM") and energy efficiency ("EE") programs be calculated under the assumption that the Company should apply a 10% summer and 90% winter seasonal allocation factor to the avoided cost associated with those programs. With its recommendation that the Commission direct the Company to re-calculate its legacy pre-existing DSM/EE programs with a 10% summer seasonal allocation factor, the Public Staff erroneously values the Company's legacy DSM/EE capacity the same as new incremental capacity from a qualifying facility ("QF"). For the reasons set forth herein, the Public Staff's recommendation, as well as the resulting $ 3,624,753.00 reduction to DEC's Vintage 2021 PPI attributed to this erroneous treatment of avoided capacity valuation, should be rejected by the Commission.

I. BACKGROUND

In its *Order Approving DSM/EE Rider*, *Revising DSM/EE Mechanism*, *and*

Requiring Filing of Proposed Customer Notice issued in Docket No. E-7, Sub 1130 on August 23, 2017 ("Sub 1130 Order"), the Commission approved a comprehensive agreement between the Public Staff and DEC ("Sub 1130 Agreement" or "Agreement") that, among other things, clarified and revised the method by which avoided costs would be updated for purposes of the PPI and DSM/EE program cost effectiveness previously outlined in the cost recovery mechanism approved by the Commission in Docket No. E-7, Sub 1032 ("Mechanism"). The revision focused on referring to the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as the guide for establishing the PPI and cost-effectiveness for Vintage Year 2019 and afterwards. Specifically, Paragraph 69 of the approved Sub 1130 Agreement provides that:

> 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 of the Mechanism (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.[1]

The Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from QFs ("Avoided Cost Proceeding") presents the Commission's framework for implementing Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The biennial determinations of the avoided cost rates reflect the then current "economic and regulatory circumstances facing QFs and the electric public utilities in North Carolina" as those economic and regulatory circumstances change over time. *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 148, issued Oct. 17, 2017 ("Sub 148 Order") at 6, 9.

Prior to the most recent 2018 Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities ("Avoided Cost Proceeding") the Commission directed the utilities in Docket No. E-100, Sub 158 ("Sub 158") to address in initial filings consideration of issues that impact the avoided capacity rates, "such as the weighting of capacity value between the summer and non-summer seasons." *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 158, issued April 15, 2020 ("Sub 158 Order") at 27. In response to the Commission's directives, on November 1, 2018, DEC filed a new rate design that reflected, among other things, changes to the previously-approved seasonal allocation weighting for capacity payments. In that filing, the new seasonal allocation was more heavily weighted to winter. Sub 158 Order at 18. The changes in seasonal allocation in Sub 158 were justified by DEC's 2018 integrated resource plan ("IRP"), which presented 90% of DEC's

[1] 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."

loss of load risk occurring in the winter. *Id*. After initial disagreement, the Public Staff ultimately supported DEC's new seasonal allocation. Sub 158 Order at 20. The Commission reviewed the various parties' positions on this issue thoroughly, stating that "the evidence in this proceeding confirms the Commission's determination in the 2016 Sub 148 Order that the high solar penetrations in Duke's service territory that it is experiencing today and expects to continue in the future will have different impacts on summer versus winter loads net of solar contribution than in the past." Sub 158 Order at 28. The Commission further agreed with DEC witness Glen A. Snider that "an assessment of historic loads without consideration of the impact of current and projected levels of solar output does not provide a complete or reasonably accurate picture of the appropriate seasonal allocation weightings to assign *to forward-looking avoided cost rates*." Sub 158 Order at 28. (Emphasis added.) Thus, the Commission noted, "DEC's *new* rates pay 90% of its annual capacity value in the winter and 10% in the summer period." Id. (Emphasis added.) The Commission then turned to the "related issue" of the availability of winter DSM programs, and directed DEC and Duke Energy Progress, LLC ("DEP") to "place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands." *Id*. at 28-29. The Commission directed DEC and DEP to address this issue in its 2020 biennial avoided cost proceeding. *Id.* at 29. Finally, the Commission concluded by observing that "these assumptions can be dynamic and can change in the future. The Commission will be receptive to revisiting these issues in future proceedings . . . ." *Id*.

Once the Commission approved these new avoided cost rates in Sub 158, they were applicable to QFs establishing a legally enforceable obligation ("LEO") after November 1,

2018. LEOs give the QF (and the utility) a date certain for determining the applicable long-term fixed avoided cost rates to be used in the power purchase agreement ("PPA") between the QF and the utility. *Order Granting Motion to Dismiss*, Docket Nos. E-2, Sub 1177 and E-7, Sub 1172, issued July 16, 2018, at 4-5. However, the Sub 158 avoided cost rates do not apply to QFs that established LEOs prior to when the Company made its avoided cost filing in Sub 158, November 1, 2018. Those legacy QFs with long-term, fixed rate contracts still receive avoided capacity and energy cost rates that were in effect when they established their LEO. *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 on or after November 1, 2018 ("new" or "incremental" QFs) receive avoided cost rates that reflect the most recently approved seasonal allocation. QFs that established LEOs prior to November 1, 2018 ("legacy QFs") receive avoided cost rates that reflect the seasonal allocation weightings when the LEO was established.

In this proceeding, the Public Staff and the Company agree that the Applicable Avoided Cost Proceeding for Rider 12 is Sub 158. Both the Public Staff and the Company agree that using the seasonal allocation weightings as an input when calculating avoided capacity values for incremental new DSM capacity resources that are built from new participation in DSM programs not factored into the Company's IRP as a load serving resource ("new DSM") is consistent with the Sub 1130 Agreement and the Sub 158 Order.[2] (Tr. at 106.) The key issue in dispute between the Company and the Public Staff is whether the Company must use the most recently approved seasonal allocation weightings as an input for calculating avoided capacity values for existing DSM programs that had been previously included in the Company's 2018 IRP forecast as a load serving resource ("legacy DSM programs") when those historic and planned DSM programs have been approved and adopted by customers. (*Id*.)

As described in the testimony of Public Staff witness Hinton, the Public Staff contends that legacy DSM program capacity should be valued the same as new QF capacity. Witness Hinton accepts the Commission's conclusion in Sub 158 that DEC is winter planning. (Tr. at 214-16.) As such, he concludes that it is appropriate to apply the seasonal allocation weighting to capacity from incremental new DSM programs; however, he goes one step further to conclude that, as a whole, the value of DEC's pre-existing legacy summer DSM programs is now diminished and they no longer have the same value for resource planning purposes in terms of a capacity resource at the expected time of peak and the dollar per kW associated with the demand reductions. (Tr. 216.) Accordingly, witness Hinton recommends that the avoided capacity cost benefits for purposes of the PPI and the cost-effectiveness of the Company's DSM/EE programs be calculated under the assumption that the seasonal allocation weighting proposed in November 2018 and

[2] The Public Staff's position on this issue appears to vary somewhat. On the one hand, witness Hinton insisted that changes to the seasonal allocation used in calculating avoided capacity costs be first addressed in the Mechanism, as revised by the Sub 1130 Agreement, before they could be brought to the Rider proceedings. On the other hand, he acknowledged that the Public Staff agreed with the Company's application of the seasonal weightings for "new DSM" even though he did not believe that was called for in the Mechanism. (Tr. at 307- 09.)

approved in October 2019[3] be applied to all DSM capacity regardless of both the continuing value of that DSM capacity and the regulatory and the avoided capacity values at the time the Commission approved the DSM programs. The Company opposes the Public Staff's recommendation because it erroneously treats legacy DSM/EE programs as new and incremental to the IRP, it is illogical when compared to DEC's sister utility, DEP's legacy DSM portfolio, it is contrary to the intent of the Sub 1130 Agreement, and because it conflicts with the public policy of the State of North Carolina of encouraging DSM/EE programs. 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 Company's Use of Seasonal Allocation Weighting in this Proceeding is Consistent with the Sub 1130 Agreement, the Sub 158 Order, and Past Commission Orders.

The Public Staff does not dispute that the Company updated the avoided capacity cost rate for estimating program cost effectiveness and the Company's projected PPI consistent with the method agreed upon and approved in Docket No. E-7, Sub 1130 by applying the 10% summer and 90% winter seasonal allocation factor to the avoided capacity cost associated with its new, incremental DSM programs. Although the Sub 1130 Agreement does not expressly and directly compel the Company to apply the seasonal allocation weightings, and neither the Company nor the Public Staff has previously included them in their calculations, the application of the seasonal allocation weighting is

[3] The Commission issued its *Notice of Decision* in Sub 158 on October 7, 2019. It included the Commission's conclusion on the Company's proposed seasonal allocation weighting in Finding of Fact No. 3. Notice of Decision at 8. Because the Notice of Decision had been issued, even though the Commission's final order had not, the Company used the seasonal allocation weightings approved in the Notice of Decision, which were included and discussed further in the Commission's subsequent Sub 158 Order. (Tr. at 108.)

wholly consistent with the intent of the Sub 1130 Agreement, which directs that 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 Avoided Cost Proceeding. The Company raised the issue of seasonal allocation weightings in the most recent biennial determination of avoided cost rates for electric utility purchases in response to the Commission's direction in the Scheduling Order for Sub 158. Sub 158 Order at 27. It was litigated and central to the Commission's conclusions in the Sub 158 Order. *See e.g. Notice of Decision*, Docket No. E-100, Sub 158 at 8; and Sub 158 Order at Finding of Fact Nos. 6 and 7 and at 17-29. Therefore, the Company's adoption of the seasonal allocation weightings in the present DSM/EE proceeding is completely consistent with the Sub 1130 Agreement as it reflects the most recent biennial determination of avoided cost rates for electric utility purchases.

Significantly, however, the Company's adoption of the recently approved seasonal allocation of avoided capacity values for new incremental programs and participation in this proceeding is also consistent with the Sub 158 Order. In that Order, the Commission directed the Company to "place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands." Sub 158 Order at 28-29. The Commission did not direct DEC to apply this seasonal allocation to QFs that had established LEOs prior to November 1, 2018, nor did the Commission instruct that legacy summer DSM program were no longer effective or were any less valuable. Before this proceeding, however, winter DSM programs had zero capacity value assigned to them for cost effectiveness and PPI calculations. (Tr. at 155.) Accordingly, and as DEC witness Duff responded to Chair Brown-Bland's inquiry, to recognize the growing need for winter capacity and to encourage EE and DSM programs that will provide winter capacity savings, the Company applied the seasonal weighting for future capacity needs of 90% in the winter and 10% in the summer to encourage the development and specific promotion of new EE and DSM programs that provide winter capacity savings. (Tr. at 107-09, 181.) The Company did so to reflect the current economic and regulatory conditions going forward. (Tr. at 160, 181.) By prioritizing the current need for winter DSM and EE going forward, however, the Company did find it necessary or appropriate to also retroactively devalue its legacy summer DSM.

B. The Public Staff's Approach Undervalues the Company's Legacy DSM/EE Programs.

Public Staff witness Hinton recommends that the Commission deny DEC's proposal to give its legacy DSM/EE programs a 100% summer weighting under the current IRP winter planning scenario, and require DEC to recalculate cost-effectiveness using a 90% winter and 10% summer allocation of avoided capacity benefits. He asserts that "[t]his would value the demand reduction benefits from DSM on the same basis as any other demand reductions the Company may realize from QFs." (Tr. at 222.) This recommendation, however, falsely equates legacy DSM/EE capacity with new QF capacity. Additionally, it establishes a flawed and rather extreme premise that the only way to encourage DEC to prioritize winter DSM programs would be for the Commission to devalue existing DSM summer resources that contribute to the fact that DEC has shifted toward winter planning. This approach ignores that DEC's 2018 IRP still predicts its summer peaks are 300 to 400 MW greater than winter peaks throughout most of the planning period, reaching over 500 MW in 2030. (Tr. at 214.) Although the PURPA method contemplates treating legacy DSM/EE programs as legacy QFs are treated for purposes of applying Avoided Cost Proceeding conclusions prospectively, it does not mandate that the Commission view the value of demand response capacity the same as the value of capacity from a QF. As DEC witness Duff testified, "there are fundamental differences between QF and DSM capacity." (Tr. at 144.)

The Commission has previously rejected the Public Staff's false equivalency of QF capacity and DSM capacity in its *Order Approving DSM/EE Rider and Requiring Filing of Customer Notice*, Docket No. E-7, Sub 1164, issued Sept. 11, 2018 ("Sub 1164 Order"). In that docket, the Public Staff attempted to argue that because the Commission had approved the use of zeros for capacity costs in years where the Company did not show a need for capacity to calculate avoided cost rates for new and incremental QFs in Docket No. E-100, Sub 148, the Mechanism compelled DEC to likewise apply zeros to its calculation of avoided capacity costs for purposes of calculating the PPI and cost-effectiveness in DSM/EE proceedings. The Commission, however, recognized that DSM provides a capacity value to customers that is different from that provided by primarily solar QFs. The Commission concluded in the Sub 1164 Order that "evaluating the contributions that DSM/EE measures make to a utility avoiding future capacity needs to determine cost-effectiveness is inherently different than the evaluation taken to determine the capacity costs avoided through the purchase of electric output from a QF." Sub 1164 Order at 44. It logically follows that assigning a 10% value for avoided capacity to an existing DSM resource, as the Public Staff urges in this case, would also undervalue this capacity resource.

The Public Staff's flawed approach values legacy DSM programs as if they were like new QF capacity. The legacy DSM programs, however, are not incremental programs;

they are not “new.” Even the Public Staff has conceded that the DSM programs included in the IRP block are stable and expected to continue for the foreseeable future. (Tr. at 114.) From a system planning perspective, the peak MW capability of the DSM programs is included in all 15 years of the IRP. (Tr. at 113, 172-73.) In other words, the legacy DSM programs are viewed as a dispatchable resource that is available for the entire 15-year IRP planning horizon. (Tr. at 114.) Notably, solar QF capacity is not dispatchable. In contrast, the Power Manager Program resource has the flexibility to dispatch any time throughout the day depending on the net load on the system after accounting for the must-take solar output on the grid. The Company’s solar QF resources contribute significantly more to the summer afternoon peak than to winter morning peak, but, as the sun sets, the contribution from solar resources diminishes. *See* Sub 148 Order at 58 (discussing how solar resources contribute to afternoon peak). As such, Power Manager is available to dispatch into the evening hours when net load is still high due to diminished solar output, a circumstance known as the “duck curve.” Additionally, if solar is lost due to midafternoon cloud cover, demand response can be used to make up for diminished irradiance. (Tr. at 113.) As an IRP resource, both existing AC demand response and existing solar resources are oriented toward summer peak demand reduction, helping to meet customer peak demand in the summer. The capacity value from these resources is at least in part why incremental resource decisions are now geared toward winter peak demand needs. (Tr. at 113.) This does not mean that the existing summer-oriented resources have less value, but recognizes that *incremental* additions to those resources, whether they are solar or DSM, would have diminished incremental value.

The stability of legacy DSM resources is also reflected in DEP's treatment of DSM resources. The Public Staff also argues, to no avail, that because DEC's DSM programs are short-lived, each year's customer participation is new and incremental. (Tr. at 114.) The fallacy of this argument becomes obvious when comparing DEC's and DEP's measure lives. Although DEC adopted a one-year measure life for DSM programs for cost-recovery purposes (DEC does not amortize for cost recovery purposes under N.C. Gen. Stat. § 62-133.9), DEP, which recovers its DSM/EE costs differently, recognizes 25 years of peak reduction impacts at the point a new customer signs up for DSM. (Tr. at 114.) The recognized measure life ties to the switch life, which is 25 years. (Tr. at 142.) In short, DEP recognizes a 25-year measure life for DSM. When DEP installs the switch, it is getting 25 years of the avoided cost value associated with the installation. As with DEC, the Commission approved new seasonal allocation weightings for DEP in Sub 158 as well – 100% winter. Consequently, the Public Staff could not logically apply the argument about the one-year measure life to DEP, because it would require retroactive application of zero value seasonal allocation weightings for a DSM resource that has already been deemed used and useful for a 25-year life.

The Public Staff's other attempt to minimize the capacity value of legacy existing DSM/EE to equate with the capacity value of new, incremental QFs also fails. Public Staff witness Hinton attempts to show that during the most recent four years of actual DSM activations, the Company has had fewer activations of summer DSM programs, which he attributes to a change in the Company's system lambda. (Tr. at 115.) As Company witness Duff explained, however, that change could just as easily be explained by the milder 2017-19 summers when compared to the summer of 2016, where summer DSM programs were activated a significant number of times. (Tr. at 115.) Witness Duff stated that his cursory examination of historical temperatures indicated that the summer of 2016 was much hotter than normal. (Tr. at 116.) No party contested witness Duff's testimony in this regard. Moreover, the full value of a summer DSM resource occurs during extreme weather days where the ability to dispatch a summer DSM program provides peak load reduction that is less expensive to customers than starting up and running a more expensive peaking generation. (Tr. at 116.) In this respect, existing summer DSM capacity provides a more reliable value to customers than new, likely solar, QF capacity. Thus, legacy DSM capacity should not be valued the same as incremental, new QF capacity.

C. The Public Staff's Position is Inconsistent with the Intent of the Sub 1130 Agreement and Past Commission Orders.

The Public Staff's retroactive application of the 10% summer and 90% winter seasonal allocation to legacy DSM programs and participation is also contrary to the intent of the Sub 1130 Agreement. Public Staff witness Hinton asserts that the Company should have foreseen its application of the seasonal allocation weightings to the Company's legacy DSM because the Company should have known that "things were going to be in flux." (Tr. at 301.) However, for the reasons discussed below, the Public Staff's approach departs from 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 12 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 102-105.). *See also,* Sub 1164 Order at 44.

Consistent with those revisions in DEC's DSM/EE cost recovery Mechanism that the Commission approved in the Sub 1130 Order, the Company derived both the avoided energy and avoided capacity using the underlying resource plan, production cost model, and cost inputs approved in the Company's most recent Avoided Cost Proceeding, Sub 158. The avoided cost calculations and rates in an Avoided Cost Proceeding are applied *prospectively* to QFs that established LEOs after the proposed rates are filed and approved. Thus, in following the PURPA method, for *legacy* DSM/EE programs already providing a capacity value underlying the resource plan used in Sub 158, the Company assumed that these resources would create a value equivalent to the cost of building a new peaker – a method that has been used in all past DSM/EE filings. For *new or incremental* DSM/EE programs, the Company applied the seasonal allocation weightings that had been recently approved in Sub 158 for new QFs. (Tr. at 105.)

Although the Public Staff protests that this application was wholly unexpected and should have been initially addressed in the Mechanism, it nonetheless readily agrees with Company's application of seasonal allocation weightings with respect to new DSM/EE programs. (Tr. at 308-09.) It is the Public Staff that then departs from the directives of the Mechanism by applying the seasonal allocation weightings to devalue legacy DSM programs that were in existence prior to the most recent Avoided Cost Proceeding. This is contrary to the intent of the Sub 1130 Agreement.

The Mechanism, specifically Paragraph 69, reflects the "PURPA method," which requires that the most recent Commission-approved Biennial Determination of Avoided Cost Rates as of December 31 of the year immediately preceding the annual DSM/EE filing date will used to derive both the PPI-focused avoided capacity costs effective for Vintage 2019 and thereafter. Sub 1130 Order at 31.

In support of the PURPA method, witness Hinton described it as follows:

> The use of PURPA-based avoided costs links the savings and financial incentives afforded the Company for its DSM/EE programs with the rates it pays QFs for avoided energy and avoided capacity.

(Tr. at 113.) 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, linked to (but not the same as) the avoided cost rates the Company pays QFs. Approved avoided capacity and energy credits are effective *prospectively*, not retroactively.

Based on the PURPA method, it is appropriate to treat the continuing capacity value for these legacy DSM programs consistently with the treatment of *legacy* QFs that had established LEOs or had signed power purchase agreements with the Company prior to November 1, 2018. These legacy QFs are now receiving long-term fixed rates (up to 15 years) that included seasonal allocation weightings that reflect the Commission's policies, avoided cost orders, and regulatory and economic circumstances in place when they were approved or planned, prior to November 1, 2018. (Tr. at 309-10.) 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 1, 2018 to modify the capacity payments to reflect the Commission's Sub 158 seasonal allocation. 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, should retain their capacity value as legacy QFs retain their long-term avoided capacity rates, fixed at the time they established their LEOs.

D. Contrary to North Carolina Policy, The Public Staff's Approach Impedes the Development and Operation of New Cost-Effective DSM, Especially Winter DSM, Programs.

The Public Staff agrees that its approach to legacy DSM programs makes them less cost-effective and changes pre-existing methods of valuing legacy DSM programs. However, the Public Staff insists the Commission ignore these impacts because the legacy

DSM program remain cost-effective, and the Company still recovers its costs for the programs (Tr. at 222, 303.) This short-sighted approach both ignores that cost-effectiveness depends on more than one factor and discourages the Company's continued development and investment in DSM programs, especially the ongoing development of winter DSM programs.

Although the Public Staff's approach does not result in the Company's legacy DSM programs being not cost-effective for Vintage 2021, the approach does have potential adverse long-term impacts on this important legacy summer resource. (Tr. at 117.) With only 10% of the avoided capacity value being recognized under the Public Staff's approach, most of the avoided costs associated with this legacy resource come from avoided Transmission and Distribution ("T&D") value. (Tr. at 117.) The Commission has required the avoided T&D rates to be studied and updated prior to 2022. If T&D costs decreased, it would further imperil the cost-effectiveness of these programs. (Tr. at 165.) Given that uncertainty, the Public Staff's approach jeopardizes the cost-effectiveness of these programs, and thereby potentially jeopardizes their continuation. Building back a DSM resource after it has become non-cost-effective is not a quick process. (Tr. at 164, 191.) Although the Public Staff tried to point out on cross-examination that avoided T&D costs may increase, this does not mitigate the Company's concern about the continued cost-effectiveness of these programs. As witness Duff pointed out, the general trends of avoided costs have been downward. (Tr. at 190.)

Ultimately, the Public Staff's short-sighted position impedes the Company's ability to be able to plan DSM programs, especially winter DSM programs. By applying the 90% seasonal allocation weighting to new, incremental EE and DSM winter programs and participation, the Company has complied with the Commission's direction in Sub 158 to develop winter oriented DSM and EE programs. (Tr. at 116, 155.) The Company has already started to discuss these types of programs within the Collaborative and embarked on hiring a consultant to investigate winter programs. (Tr. at 149, 303.) However, if seasonal allocation weightings applications can change every two years and be applied retroactively to legacy DSM and EE, planning for those resource becomes "exceedingly hard." (Tr. at 163.) To change the underlying value every two years complicates the ability to include the resource in long-term IRP planning. As DEC witness Glen A. Snider testified in Sub 158:

> Duke's seasonal allocation may continue to change over time as customer mix, customer energy usage, and changes to the summer and winter resource mix, including the continued addition of solar resources, the addition of battery storage capability, longer-term potential wind resources, additional DSM programs and other changes impacting the balance of summer versus winter resources, and other factors change.

Sub 158 Order at 24. The Commission has also declared that it "will be receptive to revisiting these issues in future proceedings." *Id*. However, under the Public Staff's proposed method, as the Company builds its winter DSM resources, it has no certainty, based on the variables listed above, that seasonal allocations may shift in the future or that T&D avoided costs may decrease. Adopting the Public Staff's approach, therefore, potentially undermines the long-term viability of winter DSM programs. As the Company is currently planning with a focus on winter DSM programs, it cannot have confidence in the ongoing value of those programs if the seasonal allocation changes in upcoming Avoided Cost Proceedings, affecting the value of the capacity and the continued cost-effectiveness of the program. *See* e.g. Sub 1130 Order at 31 (Witness Hinton discusses how the PURPA method looks at lifetime avoided energy costs over 10, 15, and 20 years; thus, a fluctuating avoided energy cost would "not provide certainty" and "would make difficult both the planning and evaluation of programs.")

The Public Staff appears to imply that the Company bears the risk of implementing DSM programs that may decrease in value and, because the Company will still recover its costs for legacy programs, the Company is not really harmed by their position. (Tr. at 302-03.) Ultimately, what the Public Staff's approach fails to acknowledge is that legacy DSM 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. When the Company implements DSM/EE programs, it is delaying the need to build new power plants. See *Order Approving Integrated Resource Plans and Requiring*

Additional Information in Future Reports, Docket No. E-100, Sub 103, issued Aug. 31, 2006, at 21 (Pre-Senate Bill 3, "[t]he Commission believes that the DSM programs implemented in North Carolina in the past have helped reduce the need for additional generation.") 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 like that associated with the earnings on a power plant. In other words, 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 as urged by the Public Staff, it violates that regulatory compact.

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 legacy DSM/EE programs should be based on avoided capacity rates reflect a 10% seasonal allocation weighting for summer-oriented programs and 90% for winter-oriented programs: (2) deny the Public Staff's downward adjustment to the Company's PPI; (3) accept the cost-effectiveness calculations performed by the Company for purposes of Rider 12; and (4) approve the Company's calculation of the DSM/EE rates for Vintage 2021 as reflected in the supplemental testimony and exhibits of DEC witness Miller.

Respectfully submitted this 13th day of August 2020.

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