STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 931
DOCKET NO. E-7, SUB 1032
DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Docket No. E-2 Sub 931 In the Matter of Application by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69 Docket No. E-7, Sub 1032 In the Matter of Petition by Duke Energy Carolinas, LLC, for Approval of Modifications to Residential Service Load Control Rider Docket No. E-100, Sub 179 In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan	**INITIAL COMMENTS OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

NOW COMES Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (together the "Companies" or "Duke Energy"), pursuant to the North Carolina Utilities Commission's ("Commission") December 30, 2022 *Order Adopting Initial Carbon Plan and Providing Direction for Future Planning*, Docket No. E-100, Sub 179, implementing N.C.G.S. § 62-110.9, which was codified by the enactment of House Bill 951, Session Law 2021-165 ("Initial Carbon Plan Order"), and its *Order Granting*

Public Staff's Motion for Procedural Relief and Scheduling Technical Conference, dated October 30, 2023 (the "Scheduling Order").

The Scheduling Order directed parties to: (i) provide comments on the issues identified in the Scheduling Order and (ii) submit for review and approval revisions to the Companies' respective demand side management ("DSM") and energy efficiency ("EE") mechanisms that are attached as Exhibit A and Exhibit B (together, the "Mechanisms" and individually, the "DEC Mechanism" or the "DEP Mechanism").[1] As explained in greater detail below, the Companies respectfully request that the Commission approve the respective Mechanisms and grant any other relief as the Commission deems just and reasonable in the furtherance of the public interest.[2]

I. Background of Mechanisms, Carbon Plan Order, and Stakeholder Process

The purpose of the Mechanisms is to encourage the Companies to pursue cost-effective DSM/EE programs that will result in lower long-term costs to ratepayers.[3] The Mechanisms encourage the achievement of these goals by allowing for cost-recovery of approved program costs and providing for certain financial incentives to the Companies for achieving savings from their DSM/EE programs. More specifically, as designed by the Commission, the Mechanisms allow the Companies to recover all reasonable and prudent costs incurred for adopting and implementing new DSM and EE measures; establish certain

[1] DEC's revised Mechanism is attached as Exhibit A and DEP's revised Mechanism is attached as Exhibit B. In each case, the exhibit contains a clean version of the revised Mechanism, along with a redlined version that shows the revisions against the existing, Commission-approved Mechanisms.

[2] Given the Companies' continued dialogue with stakeholders, the Companies expressly reserve the right to modify the Mechanisms.

[3] The history of the Mechanisms as well as the stakeholder review process are described in greater detail in the jointly-prepared pre-filed materials submitted on December 12th in anticipation of the December 18th Technical Conference.

requirements, in addition to those of Commission Rule R8-68, for requests by the Companies for approval, monitoring, and management of DSM and EE programs; establish the terms and conditions for the recovery of net lost revenues ("NLR") and a portfolio performance incentive ("PPI") to reward the Companies for adopting and implementing new DSM and EE measures and programs; and provide for an addition incentive to further encourage kilowatt-hour ("kWh") savings achievements.[4]

The Commission first approved the DEP Mechanism in June 2009 in Docket No. E-2, Sub 931, and the DEC Mechanism in October 2013 in Docket No. E-7, Sub 1032.[5] The Commission approved the most recent Mechanisms in October 2020 in those same dockets, and the terms and conditions of the Mechanisms are to be reviewed by the Commission every four years unless otherwise ordered.

Simply stated, the Mechanisms have been a resounding success by any measure, driving real results and customer benefits through a structured and deliberate collaborative process. Through the years, the Mechanisms have allowed the Companies to innovate; form partnerships with trade allies necessary to offer these programs; address the needs of their customers, including ensuring that those households struggling to make ends meet can participate in these programs; and succeed in driving customer adoption of cost-effective DSM/EE programs that result in lower long-term costs to customers.

Importantly, the Mechanisms contain clear parameters pursuant to which the Companies can develop sustainable DSM/EE portfolios, while providing a predictable

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[4] *See* Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, Docket No. E-7, Sub 1285, at 6.

[5] In February 2010, the Commission approved DEC's Modified Save-A-Watt proposal, establishing DSM/EE programs and a DSM/EE cost recovery mechanism, the pre-cursor to the DEC Mechanism.

framework for cost recovery that allows for Commission oversight at every turn. Likewise, the Mechanisms also require certain periodic reviews to ensure that the Mechanisms can adapt over time to better serve customers, while preserving the core regulatory constructs that have served this state well for over a decade.

Since 2009, customer adoption of the Companies' programs has saved approximately 3.4 gigawatts of energy and reduced peak demand by just over 4 gigawatts. The Companies are now not only regional leaders in EE, but are also each in the top 4 nationally in terms of energy saved per residential customer. The Companies' programs are incredibly cost-effective, providing customers with $2.69 in benefits for every $1 dollar invested from 2017 to 2022. This success would not have been possible without the Mechanisms, the existing regulatory construct, and the hard work of the Commission, Commission Staff, Public Staff – North Carolina Utilities Commission ("Public Staff"), and all stakeholders.

In the 2022 Carbon Plan, the Companies requested Commission support of the Companies' proposed near-term plan to "shrink the challenge" by advancing available tools to reduce demand and modify load through enhanced and new Grid Edge and customer programs. Specifically, the Companies identified and requested approval of several potential enablers that would be necessary to achieve the long-term EE savings included in the 2022 Carbon Plan (the "Proposed Enablers" discussed in detail below). The identified enablers included: 1) updating the inputs underlying the determination of utility system benefits in the Mechanisms; 2) using an as-found baseline for EE measures; 3) expanding the pools of low-income customers; and 4) developing guidelines for expedited regulatory approval of DSM/EE programs and rate designs.[6]

In its Carbon Plan Order, the Commission directed the Companies to initiate a review of the Mechanisms to consider the Proposed Enablers. In its Initial Carbon Plan Order, the Commission explained that "any modifications to individual components of the Mechanisms," including the Proposed Enablers, "must take place in the context of a full, formal review of the entire Mechanisms, so that any impacts of other components of the Mechanisms can be analyzed at the same time."[7]

On April 27, 2023, pursuant to the Commission's direction, the Companies initiated a review of the Mechanisms, which included engagement, both formally and informally, of stakeholders representing a wide variety of interests. The Companies hosted a series of eight formal stakeholder engagement sessions with the first occurring on June 29, 2023, and the final one prior to filing of the parties' initial comments occurring on January 11, 2024. Participants in these formal stakeholder engagement sessions included representatives of diverse interests from across the state including, but not limited to, the Public Staff, the Attorney General's Office (the "AGO"), the Southern Environmental Law Center ("SELC"), the Southern Alliance for Clean Energy ("SACE"), the South Carolina Coastal Conservation League ("CCL"), the Sierra Club, the North Carolina Sustainable Energy Association ("NCSEA"), the Carolina Industrial Group for Fair Utility Rates ("CIGFUR"), the Carolinas Utility Consumer Association ("CUCA"), and Walmart, Inc.

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[6] *See generally* Direct Testimony of Lon Huber and Tim Duff, Docket E-100, Sub 179.

[7] Initial Carbon Plan Order, Ordering Paragraph 31, at p. 134.

In addition to the eight formal stakeholder engagement sessions, the Companies also held a series of six bi-weekly, one-and-a-half-hour meetings for additional discussions in advance of the scheduled stakeholder meetings to allow the opportunity for focused discussions on discrete topics identified by parties regarding the Mechanisms.

The diagram included as Exhibit C to this filing illustrates the entirety of the stakeholder process, including the specific topics discussed at each session. Throughout this process, the Companies revised the Mechanisms based on the feedback, comments, and proposals received from stakeholders and interested parties and discussed proposed revisions to the Mechanisms. This stakeholder process exemplifies the Companies' long-standing commitment to in-depth and constructive dialogue to garner stakeholder feedback on issues surrounding DSM/EE, and the Companies appreciate the engagement of the Public Staff and all parties in working towards substantial amounts of consensus as is demonstrated by the consensus items summarized in the cover letter for this filing.

On October 30, 2023, the Commission issued the Scheduling Order that required a technical conference be held on December 18, 2023. The Commission requested oral presentations from the parties about the work of the stakeholder engagement process to date along with an overview of the existing Mechanisms.[8] In that same order, the Commission requested parties address certain enumerated topics in their initial comments in this docket. Those topics, as well as any revisions to the Mechanisms that are associated with those topics, are addressed one-by-one in Section II, below.

[8] A technical conference was held on December 18, 2023, where presentations were made by the Companies, Public Staff, SELC, NCSEA, and a large customer panel consisting of representatives of CIGFUR, CUCA, and Walmart. The Regulatory Assistance Project, whom the Commission had retained, also delivered a presentation on different cost recovery and incentive approaches for DSM/EE programs utilized in other jurisdictions.

II. Discussion of Topics from the Scheduling Order and Corresponding Revisions

a. *The Proposed Enablers*

The Proposed Enablers, which the Companies first identified in their 2022 Carbon Plan to maximize energy savings from DSM/EE and attain annual energy savings of 1% of eligible retail sales, include:[9] (i) updating the inputs underlying the cost benefit test in the Companies' cost recovery mechanisms; (ii) using an as-found baseline for EE measures; (iii) broadening the definition of low-income customer; and (iv) developing guidelines for expedited regulatory approval of DSM/EE programs.

1. *Updating cost benefit inputs*

The Mechanisms currently state that, for purposes of calculating cost-effectiveness for program approval, the Companies shall use projected avoided capacity and energy benefits specifically calculated for the program. The values for these benefits 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 most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of the date of the filing for the new program approval.[10] The Mechanisms further provide that, for the calculation of the underlying avoided energy

[9] In testimony in the Carbon Plan proceeding, the Companies described annual energy savings from EE of 1% of eligible retail sales as "aggressive yet achievable" if the Proposed Enablers are adopted. *See* Direct Testimony of Lon Huber and Tim Duff in Docket No. E-100, Sub 179, at pp. 7-8 and 12-16.

[10] *See* Paragraph 20 of the current Mechanisms.

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.[11] Estimated incremental evaluation, measurement, and verification ("EM&V") costs attributable to each program shall be included in the program costs for purposes of determining cost-effectiveness.[12]

The Companies propose to modernize the current framework for appropriately valuing demand-side distributed energy resources ("DERs"), EE, and DSM programs so that they are evaluated on par with zero-carbon supply-side alternatives. By making these necessary modifications, the Companies will treat EE as a first priority resource; consistent with the intent of Commission Rule R8-60(A)(f)(5).[13] Moreover, and most critical to achieving the aggressive, long-term energy savings goal of 1% of eligible load approved by the Commission in its 2022 Carbon Plan Order, the Companies believe that updating the cost benefit inputs will enable them to potentially (i) increase participation and customer incentive levels while maintaining cost effectiveness in existing programs and (ii) add new programs and measures that would not have been cost effective with the prior inputs. Expanding participation in their existing DSM/EE portfolio and offering more cost-effective, innovative new programs (with the input of the DSM/EE Collaborative and

[11] *See* Paragraph 20 of the current DEC Mechanism and Paragraph 20A of the current DEP Mechanism.

[12] *Id.*

[13] Commission Rule R8-60(A)(f)(5) provides, in pertinent part: The electric public utilities shall include an assessment of the portfolio of existing and future grid edge resources including demand-side management and energy efficiency programs consistent with the most recently filed DSM/EE cost recovery rider filed by the electric public utilities pursuant to Rule R8-69 and G.S. 62-133.9(c). The electric public utilities shall appropriately reflect grid edge resources as either load modifiers or as a resource considered on the supply side based upon the operating characteristics of the resource. For purposes of utility planning, the electric public utilities shall model energy efficiency as a load modifying resource, ensuring its priority in utility planning.

approval of the Commission) helps to shrink the challenge of transitioning to a cleaner energy future in a cost-effective manner and gives customers more tools to better manage their energy usage.

As a result, the Companies propose to use the most recently approved Carbon Plan Integrated Resource Plan ("CPIRP") to determine utility system benefits in the approved Mechanisms. Specifically, the updated inputs utilized for justifying demand-side utility programs will be based on specific costs associated with the selected marginal carbon free and storage resources in the approved CPIRP added to the system energy and capacity, inclusive of transmission and other required infrastructure. More specifically, the per kilowatt ("kW") avoided capacity benefits and per kilowatt-hour ("kWh") avoided energy benefits used will be derived from levelized average marginal supply-side resource costs utilized in the most recently approved CPIRP. The calculation of the underlying avoided energy value to be used to derive the specific avoided energy benefits will be based on the projected demand-side resource's hourly shape.

Avoided capacity benefits for DSM/EE resources will be determined using levelized costs over the recognized life of a dispatchable clean-energy capacity resource. Beginning in 2025, a Hydrogen-Capable Advanced Class Combustion Turbine ("CT"), including fixed operations and maintenance ("O&M"), major maintenance costs and intrastate fuel transportation costs, will be utilized as this capacity resource until an alternative dispatchable clean-energy capacity resource is identified in future CPIRPs. The Hydrogen-Capable Advanced Class CT is a peaking resource with the capability to convert to operating on 100% hydrogen with no associated carbon emissions. It is more efficient than anything on the Companies' systems today and the closest resource to a capacity resource. As such, it is the most appropriate resource to use for this purpose until an alternative dispatchable clean-energy capacity resource is identified in future CPIRPs.

This necessary update to the evaluation of the utility system benefits associated with DSM and EE will ensure the cost benefit metrics used to evaluate and compensate EE and other demand-side DERs enabled through customer programs appropriately recognize the customer benefits and risk reduction of zero-carbon DSM and EE on a consistent basis relative to zero-carbon supply-side alternatives in the CPIRP. Commission approval of this proposal and the required recognition of the customer benefits and risk reduction of zero-carbon demand-side programs on a consistent basis relative to zero-carbon supply-side alternatives in the CPIRP will enable the Companies to offer and operate programs in manner that allows the Companies to achieve the amount of DSM and EE energy and capacity envisioned in the CPIRP while saving customers money by cost-effectively avoiding unnecessary supply-side investments.

These updates have been incorporated into the Mechanisms through edits to several existing paragraphs. For example, Revised Paragraph 21(a) of the DEC Mechanism and Paragraph 21 of the DEP Mechanism now provide that, for purposes of calculating cost-effectiveness for program approval, the Companies shall use projected avoided capacity and energy benefits specifically calculated for the program, as derived from the underlying resource plan, production cost model, and cost inputs that generated the system benefits reflected in the Commission's most recently adopted CPIRP as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing.

Additionally, the Companies have incorporated these concepts into Revised Paragraphs 21(a) and 26(a) of the DEC Mechanism and Paragraphs 21A and 25A of the

DEP Mechanism. These revised paragraphs further provide that the projected EE portfolio hourly shape is used for the purposes of determining the avoided energy benefit—however, to ensure that EE is primarily avoiding marginal fossil fuel generation, future incremental renewable energy resources are removed from the CPIRP for purposes of determining the avoided energy benefit. To determine avoided capacity benefits for DSM/EE resources, the revisions provide that levelized costs over the recognized life of a dispatchable clean-energy capacity resource will be used with a Hydrogen-Capable Advanced Class CT (including fixed O&M, major maintenance and intrastate fuel transportation costs) until an alternative dispatchable clean-energy capacity resource is identified in future CPIRPs.

Finally, the avoided system capacity and energy benefits developed for purposes of DSM/EE program evaluation is specific to assessment of DSM/EE programs. The system capacity benefit value associated with avoided capacity savings from non-legacy DSM resources (*i.e.*, those demand-side resources not included as a resource in the Companies' approved 2018 IRPs)[14] shall be based on the seasonal allocation from the resource adequacy plan used in the Companies' most recent biennial avoided cost proceeding as of December 31 of the year preceding the date of the annual DSM/EE rider filing.[15]

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[14] Order Approving DSM/EE Rider, Subject to Final Billing Factors and Proposed Customer Notice, Docket No. E-2, Sub 1252, issued Dec. 17, 2020.

[15] Basing the system capacity benefit value associated with avoided capacity savings from non-legacy DSM resources on the seasonal allocation from the resource adequacy plan used in the Companies' most recent biennial avoided cost proceeding as of December 31 of the year preceding the date of the annual DSM/EE rider filing is consistent with current practice and prior Commission orders. Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice dated December 11, 2020, in Docket E-7, Sub 1230, at p. 11 (Finding of Fact 15: "The Company's seasonal allocation of avoided capacity value is consistent with the Commission's most recent avoided cost proceeding and is appropriate."); Order Approving DSM/EE Rider, Subject to Filing of Final Billing factors and Proposed Customer Notice dated December 17, 2020, in Docket E-2, Sub 1252, at p. 7 (Finding of Fact 14: "The Company's proposed seasonal allocation of avoided capacity value is consistent with the Commission's most recent avoided cost proceeding and is appropriate for use in this proceeding . . . .").

2. *As-found baseline*

Historically, the Companies have used the federal appliance standard as the baseline for determining energy savings impacts, knowing that the market will only offer customers equipment that is at or above the standard. The Companies' existing programs have not been designed to include customers whose equipment remains operational, and the program incentives have therefore not been designed to incent customers to replace a working unit before its fails. Thus, under the existing programs, customers are often unwilling to install more efficient equipment when their current equipment is still working (even though they may recognize that consuming less electricity could lower their energy bills sufficiently over time to justify the expenditure).

In contrast, the Companies propose to modify the Mechanisms to allow for an "as-found" baseline. The "as-found baseline" determines energy savings impacts based upon how older equipment is found actually operating in the customer's residence (*i.e.*, level of efficiency, etc.) rather than simply utilizing the federal standard as a baseline.[16] As a result, an "as-found" baseline would allow the Companies to match higher energy savings with higher customer incentives, making it more affordable to replace that equipment while it is still working—providing increased and timely energy savings to the Companies' systems.

The recognition of "as-found" baselines for certain EE measures is appropriate because the early replacement of inefficient equipment creates savings compared to the equipment being replaced, not the efficiency standard in place at the time of replacement. The Companies believe it is appropriate, when considering energy savings in the context

[16] By Order dated August 23, 2023, in Docket Nos. E-2, Sub 1308, and E-7, Sub 1278, the Commission approved an "as-found baseline" for the Companies' Smart$aver® Early Replacement and Retrofit Program.

of carbon reduction, to recognize that the amount of carbon being reduced is associated with the old usage from the old equipment compared to the new usage from the new equipment. Therefore, the Companies believe that the use of an "as-found" baseline is appropriate when a program promotes early replacement rather than replacement upon failure. However, utilizing the efficiency standard as the baseline continues to make sense for replacements on failure beyond repair.

The move to an as-found baseline will primarily impact cost-effectiveness scores for the associated programs and may allow for increased customer incentives. These increased incentives will encourage customers to replace aging equipment earlier than they otherwise would have, thereby accelerating the benefits to those customers through energy savings and to the Companies' systems through reduced demand. For example, as part of the cost-effectiveness assessment, the utility cost test ("UCT") considers the present value of the cost versus the energy savings benefit of an EE measure over the life of that measure. Today, the EE benefit for a given EE measure (such as an upgrade to a more efficient HVAC unit) is based on the difference between minimum efficiency and performance requirements set by the federal government and the efficiency of the measure being installed. However, use of the federal standard as the baseline may not fully capture the actual energy savings benefit. As a result, customers are not being offered incentives that reflect the true EE value their installed measures provide.

The use of the "as-found" baseline for certain EE measures will increase savings associated with a customer's EE investment, thereby increasing the potential incentive amount that can be provided to customers. Increased incentives will make it more affordable to replace such equipment prior to catastrophic failure, rather than simply maintaining or repairing it, particularly for low-income households who may benefit the most from lowering energy costs. In short, offering EE incentives through an "as-found" baseline has potential for greater kWh savings.

To allow for the use of an "as-found" baseline for certain EE measures, the Companies included edits in Revised Paragraph 23 of the DEC Mechanism and Revised Paragraph 24 of the DEP Mechanism to provide that, in future filings, the Companies shall specifically and clearly identify the proposed baseline—*i.e.*, the "as-found" baseline, the existing efficiency standard baseline, or a de facto baseline determined through market research—to be used to determine energy savings for all programs and measures. The revisions to the Mechanisms further require the Companies to provide the rationale supporting the use of such a baseline for the applicable program or measures and detail the specific EM&V protocols that will be utilized to appropriately measure and verify the impacts.

3. *Definition of Low-income customer*

Paragraph 3 of the existing DEC Mechanism provides that "Low-Income Programs or Low-Income Measures are DSM or EE programs, or DSM or EE measures approved by the Commission as programs or measures provided specifically to low-income customers" and Paragraph 4 of the existing DEP Mechanism similarly provides that "Low-Income Programs or Low-Income Measures are DSM or EE Programs or DSM or EE Measures approved by the Commission to be provided specifically to low-income customers." Neither of the Mechanisms specifically defines the term "low-income customer."

This arises partly because of the varying definitions—at both the state and federal level—of "low-income." As a result, expressly stating income requirements for these programs in the Mechanisms will artificially restrict the pool of customers that can participate in low-income programs. Therefore, the Companies' proposed revisions to the Mechanisms build in the necessary flexibility that will allow the Companies to tailor these programs to reach the most appropriate range of customers—with the ultimate goal of effectively reaching low-income customers in all cases subject to the Commission's ultimate approval.

For example, Paragraph 3 of the DEC Mechanism and Paragraph 4 of the DEP Mechanism have been revised to clarify that low-income programs are to be provided specifically to "customers that meet program eligibility criteria associated with an income qualification requirement used to determine eligibility of a low-income program participant." The revisions also (i) require clear delineation of the specific income qualification criteria proposed to be used to determine eligibility to participate in programs or measures when requesting approval of new low-income programs or measure additions to existing low-income programs with different eligibility criteria from those included in existing approved low-income programs; (ii) specify appropriate customer income qualification criteria; and (iii) require further explanation and demonstration if a proposed income qualification criteria differs from those used in low-income programs approved prior to 2024. Taken together, these provisions provide the Companies with flexibility to tailor low-income offerings in a way that maximizes energy savings, while ensuring that the Companies' determination of income qualification criteria remains appropriate and transparent and subject to the Commission's approval.

4. *Expedited Regulatory Approval*

As explained in the Companies' prior testimony in the Carbon Plan proceeding,[17] new technology and clean energy mandates and goals nationally are driving utilities to rapidly innovate customer programs and service offerings and to consider what changes to the existing regulatory processes are needed to ensure innovative solutions are identified, tested, deployed, and scaled at pace to meet these goals. The Companies believe that there is a need for new regulatory approaches in North Carolina to expedite the pilot programs needed to accomplish the energy transition. Innovation by nature requires the ability to quickly react and evaluate innovative concepts in a timely manner. Otherwise, the Companies run the risk of delaying innovative opportunities for its customers.

To implement such a process in North Carolina, the Companies have introduced a new Paragraph 31 in each Mechanism that includes a new Efficiency Innovation Program ("EIP") that would begin in 2025. The Companies' EIPs each will have an annual budget not to exceed $1 million that will be utilized by the Companies to test and evaluate new EE technologies, equipment, and program designs in an expedited manner and allow for scaling of said innovation at minimal cost. During annual DSM/EE rider filings, the Companies will provide an explanation of potential tests, projects, or pilots to be performed during the vintage year and a summary of the progress of the different projects included in the EIP. The Companies will also provide annual updates regarding the projects funded through the EIP at no less than two meetings of the Collaborative.

The EIP is designed to accelerate innovation, enabling the Companies to shrink the challenge posed by H.B. 951's carbon goals by evaluating potential non-DSM/EE rate

[17] *See* Direct Testimony of Lon Huber and Tim Duff in Docket No. E-100, Sub 179, at pp. 46-47.

designs, emerging technologies, and customer programs quickly and efficiently with an eye towards turning innovative prototyping concepts (or leveraging lessons learned) into pilots or programs, subject to any necessary modifications. The EIP will be considered a new EE program included in the Companies' portfolios, and prudently incurred costs will be reviewed and eligible for cost recovery through the annual DSM/EE rider but will not be eligible for recovery of NLR and PPI or Program Return Incentive ("PRI"), because the program is not subject to cost effectiveness screening.

b. *The appropriateness of continuing to allow the Companies to collect NLR in light of H.B. 951 and the Initial Carbon Plan Order*

The ability to recover NLR under the Mechanisms is a fundamental component of the DSM/EE regulatory construct that has served this state well for many years. H.B. 951 does nothing to change that construct—in fact, H.B. 951 explicitly states that "[e]xisting law shall apply with respect to EE measures and demand-side management." As such, the determination and collection of NLR under the Companies' DSM/EE riders remains appropriate for all classes of customers.

In the most recent DEC and DEP rate cases, the Commission approved the Companies' proposals for a residential revenue per customer decoupling mechanism to break the link between the Companies' profits and usage per customer in the residential class.[18] The approved decoupling mechanism trues up any difference between actual

[18] Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, and Modifying Lincoln CT CPCN Conditions, dated December 15, 2023, in Docket Nos. E-7, Sub 1134, and E-7, Sub 1276, at p. 274 (ordering that "DEC's proposed residential decoupling mechanism is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, and the proposed tariff for the associated rider, shall be, and is hereby approved"); Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, dated August 18, 2023, in Docket No. E-2, Sub 1300, at p. 244 (ordering that "DEP's proposed residential decoupling mechanism is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, and the proposed tariff for the associated rider, shall be, and is hereby approved").

residential revenue per customer, excluding variable costs, and the target residential revenue per customer, excluding variable costs. Any NLR billed to residential customers through the Companies' DSM/EE riders are subtracted from this balance to ensure that these revenues are not double-recovered from the residential customers included in the revenue decoupling mechanism.[19] It is important to note that these decoupling mechanism adjustments will be required for the collection of NLR through the DSM/EE riders that will occur in 2024 and 2025. Therefore, any modifications to the determination and collection of NLR in the DSM/EE rider proceedings will likely create more complexity and confusion in the calculations associated with the last year of the Companies' approved revenue decoupling mechanism.

The Companies' have revised the Mechanisms to appropriately reflect the Commission's order that required decoupling. In the proposed revisions to the Mechanisms, the Companies have added language to Paragraph 65(f) of the DEC Mechanism and Paragraph 71(f) of the DEP Mechanism to clarify that to the extent a revenue decoupling mechanism is adopted for customers served by the Companies, the recoverable NLR—based on kWh sales reductions and kW savings verified by the EM&V process and approved by the Commission for a vintage year for customers included in decoupling—shall be included in the calculation of the revenue decoupling mechanism. This will ensure that NLR continue to be directly tied to verified results of EE programs but are not double-recovered from customers included in the revenue decoupling mechanism.

[19] Lost revenues from non-residential customers continue to be collected through the Companies' DSM/EE riders.

As a result of prior rate case proceedings,[20] the Companies have implemented practices to ensure that NLR are calculated and treated consistent with this policy for residential customers and any other customers groups for which a decoupling mechanism may be approved. In this way, the Companies ensure that they have a transparent accounting methodology to protect customers against double-recovery, while also continuing to provide insight into the impact of the DSM/EE programs on revenues.

c. *What actions, if any, justify a utility incentive, as well as whether there should be limits imposed upon utility incentives, whether there should be a required savings threshold that must be met before incentives are earned, what metrics should be utilized in awarding incentives, whether the Mechanisms should contain both incentives and penalties like Performance Incentive Mechanisms, and the efficacy of incentive mechanisms in other jurisdictions*

As an incentive to pursue cost-effective DSM/EE programs and address the inherent conflict with the utility business model that provides return on capital investment in the utility system that is avoided by DSM/EE, the current Mechanisms provide for a PPI and a PRI, which are based on a shared savings model under which customers retain the bulk of the savings. The PPI is based on a percentage of the net benefits derived from the DSM/EE portfolio, calculated using the UCT. Beginning for Vintage Year 2022, the pre-tax PPI initially to be recovered for the portfolio for a vintage year is equal to 10.60% of the present value of the estimated net dollar savings associated with portfolio installed in that vintage year. After true-up, the upper limit on the allowed pre-tax PPI for each vintage year is the amount that produces a 19.50% margin over the aggregate pre-tax program costs for the vintage year of the PPI-eligible programs in the portfolio, and the lower limit is the amount that produces the following margins over the aggregate pre-tax program costs for

[20] *See supra* note 18.

the vintage year of those programs in the Portfolio that are eligible for the PPI: 10% for Vintage Year 2022; 6% for Vintage Year 2023; 2.5% for Vintage Year 2024; and 2.5% for Vintage Year 2025 and thereafter until completion of the next Mechanism review.

The PRI is designed to provide an appropriate financial incentive to the Companies for those DSM/EE programs that are approved by the Commission despite not projecting to be cost effective, like the Companies' programs targeting low-income customers. Therefore, to appropriately reflect the benefit of these approved programs, the PRI is based on the gross avoided costs of those programs eligible for the PRI. Beginning for Vintage Year 2022, the pre-tax PRI initially to be recovered for low-income programs and other specified societal programs not eligible for a PPI is 10.6% multiplied by the vintage year avoided costs projected to be generated by each approved PRI-eligible program.

As further incentive to aggressively pursue savings from cost-effective DSM/EE, the Companies may receive an additional incentive of $500,000 if they achieve annual energy savings of 1.0% of their prior year's system retail electricity sales in any year during the four-year 2022-2025 period. But the EE revenue requirement will be reduced by $500,000 if annual energy savings of 0.5% of retail sales (net of sales to opt-out customers) is not achieved.

The incentive structure in the Companies' DSM/EE Mechanisms has a demonstrated track-record of promoting EE, with the Companies' energy savings achievements regularly being recognized as the highest in the region and above the national averages for utilities. The shared savings structure underpinning the PPI incents the Companies towards two objectives: (i) save as much energy and capacity through their programs as possible and (ii) achieve such savings in the least-cost manner possible, which is how the net benefit realized by the utility system is maximized. In other words, it is a near perfect alignment of interests between the utility and customers. Another strength of a shared savings structure utilizing net benefits calculated under the UCT is that the net benefits recognize long-lived measure savings by looking at the net present value of the system benefits recognized over the life of the EE measure installed by a customer. As a result, the system benefits from a measure delivering savings over multiple years will be higher than those delivering savings in a single year.

At this time, the Companies do not believe that any changes to the incentive structure are necessary to enable additional EE and are not proposing any revisions to the existing structure at this time. The incentive structure under the existing Mechanisms remains appropriate because it serves to reduce the foregone opportunity costs associated with pursuing DSM/EE instead of the traditional supply-side resources. Eliminating or reducing the incentive would unnecessarily penalize the Companies for pursuing more aggressive DSM/EE efforts that are in accordance with state law, conflict with stated policy goals in Senate Bill 3 of 2007 and H.B. 951 and damage the regulatory construct that has worked well in advancing DSM/EE in North Carolina.

Additionally, the Companies find it difficult to make an apples-to-apples comparison regarding the efficacy of incentive mechanisms in other jurisdictions (a topic cited in the Scheduling Order) given that utility incentive structures in other states may contain key differences reflecting that specific jurisdiction. These differences can arise in a number of ways, including whether energy and demand savings are based on gross or net, the differences in recognized assumptions on system benefit or avoided costs, and considerations for differences in rate structures. Although these specifics are important and vary from jurisdiction to jurisdiction, utilities and regulators in other states typically recognize the need for a mechanism to incentivize the achievement of a cost-effective DSM/EE portfolio—which is a concept long-recognized in this state. Additionally, some utilities have proposed performance incentive mechanisms not previously recognized in their respective jurisdictions to account for the fact they are being required to do more DSM/EE (whether as a result of state policy, statutory mandates, etc.).[21] In general, the Companies believe that their incentive mechanisms fall within the range of the incentive levels in other jurisdictions. Most importantly, incentive mechanisms must be appropriate for and reflect the realities of the utility's system. As such, comparisons to other jurisdictions and corresponding incentive structures need to be viewed with the understanding that multiple important technical and system conditions and regulatory mechanisms vary from jurisdiction to jurisdiction.

Finally, while the Companies have not proposed any changes to the utility incentive structure, in the most recent stakeholder meeting on January 11th, stakeholders shared potential modifications to the incentive structure. Given the timing of the meeting, there was not adequate time to get broad stakeholder feedback on the proposals and develop consensus around a potential modification. However, the Companies did identify a common theme in two proposals—a performance tiering of the PPI percentage tied to the amount of annual efficiency achieved. The Companies believe that this type of structure

[21] *See* Pub. Serv. Comm. of Md. Order No. 90957 (Order Authorizing Transition to 2024-2026 Program Cycle) (Dec. 29, 2023), at p. 74 (discussing utilities' proposed PIMS and sending PIM structure to Cost Recovery Work Group to further refine and finalize); State Corp. Comm. of Kan. Order on Evergy's Application and Settlement Agreements, at pp. 1, 17 (noting that state had made "little progress" with respect to EE programs, stating that intent of the order was to "implement the goals of our State's highest policymakers and ensure those Kansas residents and businesses with the greatest need to control their bills have options available to do so," and setting utilities' earnings opportunity level at 15% retention of net benefits).

may potentially be further developed with stakeholders after parties' initial comments are filed. It was also suggested that if PPI levels were tied to annual energy saving achievements that an alternative incentive structure could be added to promote increased energy savings from income qualified programs, while yet another incentive structure could be tied to the development and successful implementation of Active Load Management. The Companies appreciate the effort to develop these new alternative proposals, believe that they have merit, and should also be further explored with the broad stakeholder group.

d. *How savings and benefits should be calculated and valued, including whether non-energy benefits should be included in particular cost-effectiveness tests, whether carbon reduction benefits should be separately accounted for, and the extent to which differential value to the system should be reflected, if at all, when quantifying anticipated costs and benefits of DSM/EE measures, among other issues*

With respect to non-energy benefits ("NEBS"), the existing Mechanisms provide that NEBS, "as approved for use by the Commission, may be considered in the determination of TRC results." As contemplated by this existing language, the Companies are proposing to modify the definition of Total Resource Cost Test ("TRC") to indicate that non-energy benefits "will be used" in the determination of TRC results "beginning in Vintage 2025." Specifically, Revised Paragraph 15 of the DEC Mechanism and Paragraph 16 of the DEP Mechanism now incorporate NEBS within the TRC by including a NEBS multiplier that is applies to the value of energy savings in the numerator of the cost-effectiveness test.

The Companies also propose to specifically define "Non Energy Benefits" as "a variety of positive and negative effects to utilities, participants, and society beyond electric savings realized due to program interventions" and to specify that "[t]he identification and valuation of the NEBS will be consistent with the April 25, 2023, report by Skumatz Economic Research Associates, Inc., entitled 'Non-Energy Benefits/Non-Energy Impacts (NEBS/NEIS) for Selected Programs in the Duke Energy Carolinas and Duke Energy Progress Portfolios.'" The Companies' proposed definition further specifies that "[t]he NEBS Multipliers are located on Page 11 of the report in Figure ES.7: Estimated Multiplicative "Adders" by Perspective for the Programs - (Ratio of NEBs/NEIs) over Program Bill Savings," and that "[t]he NEBS values will be utilized until the next NEBS analysis is ordered by the Commission," and that "[a]ny subsequent NEBS study will continue to estimate NEBS associated with the TRC."

Inclusion of NEBS in TRC is appropriate because the TRC is designed to measure the relative costs and benefits to participants and non-participants alike. Inclusion of NEBS provides a more complete view of those benefits by accounting for benefits experienced by customers outside of energy savings alone—such as improved quality of life. As a result, inclusion of NEBS in the TRC provides a more holistic assessment of costs and benefits experienced by customers.[22] However, inclusion of NEBS in other cost-effectiveness tests is a complex question. For example, because NEBS are experienced by customers and are not benefits that accrue to the overall utility system, inclusion of NEBS in the UCT would be inappropriate because the UCT compares only the benefits and costs realized by utility the system from DSM/EE and would not seem to be appropriate for inclusion in the net benefit calculation underlying the PPI. As a result, at this time, the

[22] *See* Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms, dated October 20, 2020, in Docket Nos. E-2, Sub 931, and E-7, Sub 1032, at p. 3-4 (noting that substantive revisions including a provision that "the Commission will assess whether it is appropriate to use non-energy benefits in the determination of cost-effectiveness under the Total Resource Cost Test (TRC)").

Companies believe that NEBS are only appropriate for inclusion in the TRC. The Companies believe inclusion of NEBS in the TRC will provide insight into those benefits in a transparent manner, while allowing the Commission and stakeholders to understand the impact the inclusion of NEBS on the results. However, the Companies agree that any subsequent NEBS studies will "continue to evaluate any potential NEBS that could be applicable to the UCT."

With respect to whether carbon reduction benefits should be separately accounted for, there is no explicit carbon value in the Carolinas, so such benefits are difficult to quantify. However, the Companies have acknowledged the impact of the Clean Energy Transition on the system benefits associated with DSM/EE in their proposal to update system benefits to be based on the CPIRP. As a result, to the extent such a value is established in North Carolina, the Mechanisms will be flexible enough to account for such value.

e. *Definitional changes, including how to define "low income" customers, different program types, cost effectiveness, and measure baselines*

As discussed throughout this filing, the Companies are proposing several revisions that are responsive to this topic, including:

- Revising the definition of "Low-Income Programs or Low-Income Measures" to expand the pool of eligible customers;
- Revising the definition of "Total Resource Cost (TRC) test" and adding a definition of "Non-Energy Benefits" as discussed above; and
- Proposing the use of an "as-found" baseline for certain EE programs.

f. Whether the same cost-effectiveness measures should be applied to all programs

The Companies are not proposing any changes to the cost-effectiveness measures to be applied to the programs. Applying different cost-effectiveness measures to different programs would create unnecessary administrative burdens. The Companies are also not advocating for any change to the existing Commission practice of approving certain programs that do not pass a cost-effectiveness screen (e.g., income-qualified programs, etc.).[23]

g. *Financial reporting requirements*

The Companies are proposing only clarifying revisions to the financial reporting requirements in the Mechanisms. Specifically, revised Paragraph 90 of the DEC Mechanism updates the reporting to account for current cost recovery instead of Save-a-Watt recovery which is no longer applicable and Paragraph 96 in the DEP Mechanism clarify that (i) reporting on the PRI is to be included in its quarterly ES-1, (ii) reporting in the ES-1 on NLR incentives will be adjusted to appropriately reflect the NLRs being returned to customers through the annual revenue decoupling mechanism, and (iii) the Companies' North Carolina retail jurisdictional earnings set forth in the supplementary schedules shall exclude the effects of the PRI.

h. *How to most effectively encourage industrial and commercial participation in DSM/EE programs, given that the right of industrial and large commercial customers to opt-out of ratepayer-funded DSM/EE measures is codified at N.C.G.S. § 62-133.9(f), and whether to change the threshold for a "large commercial customer" under Rule R8-69 that can opt-out*

At this time, the Companies are not proposing any change to the threshold for a "large commercial customer" under Rule 8-69 that can opt-out. However, the Companies are hopeful that approval of the Proposed Enablers will allow the Companies to offer higher

[23] Importantly, certain programs that do not pass cost-effectiveness screens may offer broader benefits warranting approval of such programs.

incentives for DSM/EE programs and measures, thereby making their DSM/EE programs more attractive to industrial and commercial customers. Absent these proposed modifications, the options available to the Companies to enhance the likelihood of additional participation will be very limited.

i. *Current EM&V practices*[24]

Presently, EM&V of the Companies' DSM/EE programs is conducted by an independent third party using a nationally recognized protocol to ensure that programs remain cost-effective.[25] The Commission may approve modifications to the protocol to reflect the evolution of best practices. Initial EM&V results are applied retrospectively to replace initial estimates of impacts.[26] For the purposes of the vintage true-ups, the initial EM&V results are considered actual results for a program until the next EM&V results are received. The new EM&V results are then considered actual results going forward and applied prospectively for the purposes of truing up vintages from the first day of the month immediately following the month in which the study participation sample for the EM&V was completed. This EM&V will continue to apply and will be considered the actual kWh/kW per unit reductions until superseded by new EM&V results.

The Companies are not proposing any material modifications to EM&V practices described above. However, the Companies are proposing certain revisions to the EM&V provisions and the Collaborative provisions in the Mechanisms to create enhanced

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[24] *See* Paragraphs 35 to 37 of the current DEC Mechanism and Paragraphs 32 to 34 of the current DEP Mechanism.

[25] One exception to this statement is DEP's DSDR Program for which the EM&V is conducted by DEP itself.

[26] EM&V for the DEC's Non-Residential Smart$aver Custom Rebate Program does not apply retrospectively, and this program is trued up based on the actual participants and projects undertaken.

transparency related to the development of EM&V plans to ensure that interested stakeholders can learn about and comment on EM&V plans being developed.

Specifically, revised Paragraph 46 of the DEC Mechanism and Paragraph 29 of the DEP Mechanism provide that the Companies will provide updates on the creation of new EM&V plans and any material modifications to existing EM&V plans and will make the new EM&V plans and modified EM&V plans available at the request of any stakeholder.

Revised Paragraph 37(b) of the DEC Mechanism and Paragraph 34B of the DEP Mechanism further provide that the Companies will provide testimony detailing the projected EM&V plans anticipated to be developed in the calendar year in which the rider filing is made. Prior to implementing new EM&V plans or making material modifications to existing EM&V plans, the Companies will share the EM&V plans or modifications with the Public Staff and with other stakeholders upon request. The Public Staff and any stakeholder electing to receive the EM&V plan may provide feedback on the plans or major modifications, and the Companies will identify what actions, if any, they intend to take in response to the feedback and provide justification for any disagreement with the feedback.

j. *Cost recovery issues such as the splitting of vintage years, whether vintage years should be considered complete after a certain period of time for purposes of cost recovery, amortization, deferral, allocations, and recovery of indirect costs (e.g., administrative, marketing, and education)*

The current Mechanisms remain appropriate with respect to these issues. However, the Companies have received feedback about vintage years remaining open for too long. The Companies have considered this issue and would be agreeable to considering a vintage year to be "complete" for purposes of annual DSM/EE rider proceedings 36 months after December 31 of the applicable vintage year.[27]

k. *Composition and role of the DSM/EE Stakeholder Collaborative, including whether attorneys should be allowed to participate*

The current Mechanisms contemplate a Collaborative for the Companies. The Collaborative is an advisory group made up of interested stakeholders from across North and South Carolina representing a wide array of customer groups and interests related to EE and demand response. The Collaborative serves as an open forum for the sharing of information and discussion of topics related to EE including program design and development, program evaluation, regulatory and other market conditions that will impact program performance, specific issues or topics as requested by the North and South Carolina Utilities Commissions in orders regarding DSM/EE matters, and other topics or issues to achieve the most demand and energy savings possible. The stakeholders collaborate on new program ideas, review modifications to existing programs, ensure an accurate public understanding of the programs and funding, review the EM&V process, give periodic status reports on program progress, help to set EM&V priorities, provide recommendations for the submission of applications to revise or extend programs and rate structures, and guide efforts to expand cost-effective programs for low-income customers.

To facilitate further expeditious advancement of new programs and enhancements, the Companies have revised the Mechanisms to provide for "focused working groups of interested parties to further investigate initiatives and topics" and "report[s] to the

[27] The Companies note that although no changes are being proposed at this time to address these issues, revised Paragraph 58 in the DEP Mechanism notes that DEP's three-year amortization period (which DEC's Mechanism does not include) will be eliminated if the Companies eventually merge and a consolidated mechanism is proposed.

Collaborative on the progress of all established working groups and . . . annual update[s] to the Commission, on establishment and progress of any working groups convened during a vintage year in the Annual DSM/EE Rider filing."

Given the success of the Collaborative to date, the Companies are not proposing any changes to the composition or role of the Collaborative. The Collaborative continues to operate successfully without the presence of attorneys at the meeting, and the Companies do not believe that a change to the fundamental framework of the Collaborative to allow for the presence of attorneys at meetings is necessary at this time. However, the revised Mechanisms do incorporate new provisions in revised DEC Paragraph 45 and revised DEP Paragraph 28 that will ensure all parties, including counsel for such parties, will be provided transparent, informative materials about the Collaborative meetings—such as an agenda at least 21 days in advance of a meeting and a subsequent slide deck of what was presented at the meeting within 24 hours of the meeting's closure. Additionally, the Mechanisms specifically provide that counsel for any party can request certain additional topics or informal working groups, if desired. This represents an acknowledgement in the revised Mechanisms that the Collaborative is an open space that welcomes ideas and broad collaboration.

l. *Identify Mechanism changes that would prioritize persistent, cumulative savings measures and reduce reliance on the achievement of short-lived behavioral measures*

As discussed above, the changes allowing the use of the "as-found" baseline encourage the early replacement of inefficient equipment. Use of the as-found baseline for certain programs and the proposed updates to system benefits should allow the Companies to move forward with offering higher customer incentives. Higher incentives will aid customers in procuring energy efficient equipment resulting in longer-lived savings.

Further, although not specifically part of the Companies' DSM/EE program portfolio (because no rebate or incentive is offered), the Residential Service-Tariffed On-Bill Program ("TOB Program"), as approved by the Commission in Docket Nos. E-2, Sub 1309, and E-7, Sub 1279, may also help to facilitate longer-lived measures. The TOB Program is designed to promote the Companies' DSM/EE portfolios and eliminate upfront costs for customers when installing approved measures. By removing the significant burden of upfront costs, the TOB Program will provide customers with access to EE measures that may have been too costly without the TOB Program's repayment options.

m. *A one-time, non-precedential reconciliation procedure to allow Vintage 2025 projections to be filed in the 2025 DSM/EE rider proceedings and then trued-up to reflect actual costs and results during the 2026 annual DSM/EE cost recovery proceedings*

During the 2022 Carbon Plan proceeding, the Companies emphasized that, because of the complexity, scope, and goals of energy transition contemplated in the Carbon Plan, and the vital role that EE would play in assisting customers with that transition, there was value in the Commission acknowledging and affirming in its 2022 Carbon Plan order that these Proposed Enablers should be adopted in the appropriate forums so that the Companies' critical work to "shrink the challenge" could begin as soon as possible.

On September 7, 2023, the Public Staff filed a motion requesting the Commission issue a scheduling order to allow for the filing of the initial comments concerning the Proposed Enablers and the full Mechanisms review on or before January 26, 2024, with reply comments to be due by March 29, 2024.

The Companies did not object to the proposed scope and filing deadlines in the Public Staff's motion, but did note that the amount of time that had already elapsed, coupled with the amount of time required to address the numerous, wide-ranging issues identified by Public Staff, could impede not only the Companies' efforts to "aim higher than the current 1% of eligible load forecast savings" as directed by the Commission in the 2022 Carbon Plan Order, but also the Companies' efforts to achieve the 1% eligible load energy savings.

To accommodate the Public Staff's proposed scope and breadth of review of the Mechanisms with the stakeholder input that the Commission directed, and to ensure that the Proposed Enablers and any other necessary and appropriate revisions to the Mechanism go into effect as soon as possible to help "shrink the challenge," the Companies are proposing a one-time, non-precedential reconciliation procedure. The Companies believe that if the Commission issues an order on the proposed revisions by no later than the second quarter of 2024, the Companies can make the Commission-approved revisions effective for Vintage 2025. The Companies therefore request a one-time, non-precedent setting reconciliation or "true-up" of Vintage 2025 to reflect all Commission-approved changes to the Mechanisms resulting from the present review.

If approved, the current Mechanisms would remain in effect through the end of 2024, and the Companies would file DEC Vintage 2025 and DEP Vintage 2025 projections for recovery of program costs, NLR, and utility incentives in the upcoming 2024 annual rider proceedings under the existing Mechanisms. In the 2026 annual DSM/EE cost recovery proceedings, the Companies would true up Vintage 2025's projections not only for actual participation, program costs and EM&V results through the Experience

Modification Factor ("EMF") rider, as is typically done under Commission Rule R8-69(f)(1)(iii) – (viii), but also for all Commission-approved modifications to the Mechanisms approved by the Commission by the end of 2024. Such a process would allow the revisions to the Mechanisms to apply to Vintage 2025 without unnecessary delay.

The proposed one-time reconciliation directly supports the Companies' ability to implement new programs and program modifications that are necessary to achieve the EE savings (1% of eligible retail load) and are critical to meeting the Companies' future carbon emission goals. The one-time reconciliation will allow the Companies' DSM/EE riders to appropriately reflect and capture the updated benefits to the utility systems of EE and avoids mismatch between higher program costs and system benefits that would result under the current reconciliation process. Without this one-time Vintage 2025 reconciliation, new programs and program modifications that will enable the Companies to achieve its emission goals will not be effective until 2026 at the earliest. Effectively, without approval of the one-time reconciliation, all parties and the Companies' customers will lose a year in implementing any approved modifications to the Mechanisms that will ultimately impact implementation of DSM/EE programs that benefit customers and help achieve the Companies' carbon emission goals.[28]

To accommodate the proposed one-time reconciliation for Vintage Year 2025, the Companies have revised Paragraph 82 of the DEC Mechanism and Paragraph 88 of the DEP Mechanism.

n. *Any other relevant issues*

1. *Avoided Transmission and Distribution ("T&D") Costs*

[28] As recognized in the Order Granting Public Staff's Motion for Procedural Relief and Scheduling Technical Conference, dated October 30, 2023, the SELC, CIGFUR, and NCSEA have all expressed support for the concept of a one-time reconciliation.

The Mechanisms approved in 2020 provided that the Companies and Public Staff would review Avoided T&D Costs no later than December 31, 2021, and make recommendations for any adjustment in the rider proceedings thereafter. The Mechanisms further provided that Avoided T&D costs will be reviewed at least every three years and will be updated if they change by at least 20%.

The review of Avoided T&D Costs was concluded in 2022.[29] Upon completion of the review, the Companies and Public Staff agreed (i) that the Avoided T&D rates agreed to in late 2021 should continue to apply to the upcoming DSM/EE rider proceedings setting cost recovery for Vintage 2024 and Vintage 2025, thereby allowing DEC and DEP to continue using the agreed upon Avoided T&D rates and associated escalator rates until the next Avoided T&D study is completed and reviewed with the Public Staff and (ii) that the next Avoided T&D Study will occur in 2024 and will be applied beginning with Vintage Year 2026, which will be reviewed in the calendar year 2025 DSM/EE rider proceedings.

In Revised Paragraphs 80 and 81 of the DEC Mechanism and Paragraphs 86 and 87 of the DEP Mechanism, the Companies incorporated the agreement to jointly review with the Public Staff, no later than December 31, 2024, the avoided transmission and avoided distribution (avoided T&D) benefits to be used in the Companies' calculations of cost-effectiveness and achieved net dollar savings utilizing the agreed upon process that was jointly developed with the Public Staff in 2022. The revised language further reflects the prior agreement that any updates to the avoided T&D benefits would be applied for the

[29] In Docket Nos. E-2, Sub 1294, and E-7, Sub 1265, the Commission was advised that the review of Avoided T&D Costs would not be completed by December 31, 2021, and that such review should be finalized before the end of 2022. By letter dated December 19, 2022, in those same dockets, Public Staff further informed the Commission that the review was complete.

projection of Vintage Year 2026 in the Companies' 2025 Annual DSM/EE Rider Filings and that the per kW avoided T&D benefits used to calculate net savings for a Vintage Year shall be reviewed and updated at least every three years.

2. *Reserve Margin Adjustment Factor ("RMAF") and Production Demand Allocation Method*

In the proposed Mechanisms, the Companies have included certain non-substantive revisions related to the RMAF in Revised Paragraph 21(b) of the DEC Mechanism and Paragraph 21B of the DEP Mechanism and to the use of the production demand allocation method to allocate the aggregated costs of the DSM programs in Revised Paragraph 55(b) of the DEC Mechanism and Paragraph 50(d) of the DEP Mechanism.

o. *Any issues directed by the Commission to be considered*

By Order dated December 19, 2023, in Docket E-2, Sub 1322, the Commission stated its intent to include within this Mechanism review "a full evaluation of the practice and methodology of including participant and non-participant spillover in the calculation of energy savings."

The Companies presently perform calculations for spillover (*i.e.*, an estimate of savings resulting from the installation of energy-efficient projects completed without a program incentive but that still was influenced by the program). Spillover, when combined with free ridership (an estimate of the proportion of the program's savings that would have happened in the absence of the program), produce the program-level Net-to-Gross ("NTG") ratio. The Companies differentiate between participant spillover ("PSO"), the attribution of savings to the program for equipment that participants installed without the incentive that was influenced by the program; and nonparticipant spillover ("NPSO"), the attribution of savings to the program for equipment contractors install for customers without a Duke Energy incentive that was influenced by the program. The NTG ratio is then multiplied by the gross verified energy savings resulting from the impact evaluation activities to determine the program's net verified energy savings.

Spillover savings from non-participants represent the additional system benefits that are achieved when a non-participant implements EE measures or practices as a result of the program's influence and recognized by all customers regardless of opt-out status arising from operating effective programs. Importantly, the non-participant EE activities generating these savings are not naturally occurring; rather the EE resulting in the additional NPSO benefit is occurring indirectly as result of program costs that the Companies incur to train its DSM/EE allies. Generating additional energy savings by influencing contractor practices is foundational to the Companies' EE programs' theories and activities—just as it is for EE programs throughout the Carolinas and the country and is based on an industry-standard, transparent methodology found in the Pennsylvania Evaluation Framework. The Department of Energy's Uniform Methods Project is the basis of the Pennsylvania Evaluation Framework, and it is consistent with other established frameworks to provide free ridership and spillover estimation (Pennsylvania Framework, p. 57). Since the Pennsylvania Evaluation Framework indicates that free ridership is an established approach to calculate reductions in net savings, so should NPSO continue to be included in the calculation of additional program's net savings.

III. Conclusion

Based on the comments herein, the Companies respectfully request that the Commission approve the respective Mechanisms attached as Exhibit A and Exhibit B and grant any other relief as the Commission deems just and reasonable in the furtherance of the public interest.

WHEREFORE, the Companies respectfully request that the Commission:

(1) Approve the respective Mechanisms;[30] and

(2) Grant any other relief as the Commission deems just and reasonable in the furtherance of the public interest.

Respectfully submitted this 26th day of January 2024.

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

s/ ______________________________

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[30] Given the Companies' continued dialogue with stakeholders, the Companies expressly reserve the right to modify Mechanisms.