STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1276

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
	)	**POST-HEARING BRIEF**
Application of Duke Energy Carolinas,	)	**OF THE**
LLC For Adjustment of Rates and	)	**NORTH CAROLINA**
Charges Applicable to Electric Service	)	**ATTORNEY GENERAL'S OFFICE**
in North Carolina and Performance-	)	
Based Regulation	)	

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Pursuant to Commission Rule R1-25 and the Commission's *Notice of Due Date for Proposed Orders And/Or Briefs* filed in the above-captioned docket on September 11, 2023, the North Carolina Attorney General's Office (AGO) respectfully submits this post-hearing brief regarding the application for a general rate increase filed by Duke Energy Carolinas, LLC (DEC, Duke, or the Company).

PROCEDURAL BACKGROUND

In October 2019, Governor Cooper issued a Clean Energy Plan report, which called for the development of a stakeholder process to evaluate alternative approaches to utility ratemaking. A number of stakeholders participated in that stakeholder process, called the North Carolina Energy Regulatory Process (NERP), including Duke Energy, the AGO, the Public Staff, the Commission, environmental organizations, municipalities, and industry groups.

On October 13, 2021, Governor Cooper signed House Bill 951, S.L. 2021-165, which adopted many of the recommendations put forward by the NERP. Section 4 of House Bill 951, which contained the provisions related to performance-based regulation, were codified as N.C.G.S. § 62-133.16.

The Company filed its initial application for performance-based regulation on January 19, 2023. In addition to the application, the Company filed direct testimony of 25 expert witnesses in support of the application.

On May 19, 2023, the Company filed supplemental testimony of 14 expert witnesses proposing revisions to the Company's initial application. Second Supplemental Testimony was filed on June 19, 2023 of two expert witnesses. Those same two expert witnesses filed third supplemental testimony on July 19,

2023. In addition, on that date, the Company filed the second supplemental testimony of four additional witnesses and the supplemental testimony of one witness.

On July 19, 2023, the following intervenors filed expert witness testimony: the Public Staff; the AGO; the North Carolina League of Municipalities (NCLM); the Sierra Club; the Commercial Group; the North Carolina Justice Center, the North Carolina Housing Coalition, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Vote Solar (NCJC *et al*.); the Fayetteville Public Works Commission; the Carolina Industrial Group for Fair Utility Rates III (CIGFUR III); the Kroger Company and Harris Teeter, LLC; the Carolina Utility Customers Association (CUCA); and the North Carolina Waste Awareness and Reduction Network (NCWARN).

On August 4, 2023, the Company filed 25 sets of rebuttal testimony on behalf of 27 expert witnesses.

On September 9, 2022, the Company, Duke Energy Progress, LLC (DEP), the Public Staff, CIGFUR II, and the Carolina Industrial Group for Fair Utility Rates III (CIGFUR III) entered into an Agreement and Stipulation of Partial Settlement related to cost allocation methodologies for the Company's production and transmission demand costs (Cost Allocation Settlement).

On April 27, 2023, DEP, DEC and the Public Staff entered into a Transmission Cost Allocation Agreement and Stipulation of Settlement regarding the proper transmission cost allocation adjustment for DEP and DEC.

On May 4, 2023, DEP, DEC, NCJC *et al*., and the Public Staff entered into an Agreement and Stipulation of Partial Settlement Regarding Low Income Affordability Performance Incentive Mechanisms and Affordability (Affordability Settlement).

On August 22, 2023, DEC, CIGFUR III, and the Public Staff entered into an Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics and Decoupling Mechanism (PIM Settlement), which addressed Performance Incentive Mechanisms (PIMs), tracking metrics, and the electric vehicle (EV) adjustment to the Company's proposed decoupling mechanism.

On August 22, 2023, the Company and CIGFUR III entered into an Agreement and Stipulation of Settlement regarding a power quality pilot program and/or further discussion of an alternative (Power Quality Settlement).

On August 22, 2023, DEC and the Public Staff, and CIGFUR III entered into an Agreement and Stipulation of Partial Settlement regarding various contested revenue requirement issues (Partial Revenue Requirement Settlement).

On August 25, 2023, the Company, the Commercial Group, the Kroger Company, and Harris Teeter entered into a Partial Rate Design Agreement and Stipulation of Settlement, that "increase[s] the proportion of total revenues recovered through demand charges for the Schedule OPT-V-Secondary sub-class by 5% (relative to current rates) in Year 1 of the Multiyear Rate Plan, from 37.9% to 42.9%," with "a corresponding revenue neutral decrease to the proposed on-peak, off-peak, and discount energy charges." (Partial Rate Design Agreement at 4). The parties also agreed that "[i]n Year 2 and Year 3 of the Multiyear Rate Plan, each of the demand and energy charges will be increased by an equal percentage in order to recover the target revenue requirement. (*Id.*)

ARGUMENT

I. THE COMPANY'S REQUESTED 10.4% RETURN ON EQUITY IS NOT JUSTIFIED.

A utility's rate of return on common equity (ROE)

> is the return that a utility is allowed to earn on its capital investment, which is realized through rates collected from its customers. The ROE affects profits to the utility's shareholders and has a significant impact on what customers ultimately pay the utility. The higher the ROE, the higher the resulting rates that customers will pay to the utility.

State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 485 n.1, 739 S.E.2d 541, 542 n.1 (2013) (*Cooper I*) (citation omitted). N.C.G.S. § 62-133(b)(4) provides the Commission shall fix a rate of return that

> will enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, . . . to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors.

Section 62-133(b)(4) is meant to advance the dual goals of assuring sufficient shareholder investment in the utility while also ensuring the lowest possible cost to the using and consuming public. The cost of equity must be estimated and is meant to reflect the risk of a given investment as compared to alternative investment opportunities and to investors' current opportunity cost of investing in that company. (Tr. vol. 8, 205-06; Tr. vol. 9, 59)

Our state Supreme Court has explained that "the rate of return on common equity . . . is the most expensive form of capital accumulation, which expense is ultimately borne by the rate payer." *State ex rel. Utilities Commission v. Public Staff*, 331 N.C. 215, 222-23, 415 S.E.2d 354, 360 (1992) (cleaned up). Accordingly, "customer impact weighs heavily in the overall rate setting process, including . . . the Commission's [deciding the] appropriate authorized return on equity." Order Granting General Rate Increase, No. E-7, Sub 1026, at 24 (N.C.U.C. Sept. 24, 2013) (Sub 1026 Order). Impact to customers is not just an "afterthought." *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. To the contrary, the Commission is tasked with "set[ting] rates *as low as possible* consistent with the dictates of the United States and North Carolina Constitutions." Sub 1026 Order at 25 (citing *State ex rel. Utils. Comm'n v. Public Staff*, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988) (emphasis added)). The Court has emphasized that "the primary purpose of Chapter 62 of the General Statutes is not to guarantee the stockholders of a public utility constant growth in the value of, and in the dividend yield from, their investment, but is to assure the public of adequate service at a reasonable charge." *Cooper I,* 366 N.C. at 494-95, 739 S.E.2d at 548. The Commission must also set forth sufficient findings of fact regarding the impact of changing economic conditions upon consumers when setting the appropriate ROE.

There are two key approaches that are used to determine the appropriate ROE: Discounted Cash Flow (DCF) and the Capital Asset Pricing Model (CAPM). "The DCF model posits that a stock price equals the sum of the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital." (Tr. vol. 14, 55) "The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security." (*Id.* at 77) There are variations on each of these methodologies (*Id.* at 142-43), including Empirical CAPM (ECAPM), Constant-Growth DCF, Sustainable-Growth DCF, etc.

One of the key steps in determining the appropriate ROE is identification of a proxy group. The two bedrock cases from the Supreme Court of the United States that address utility ROEs are *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 88 L. Ed. 333 (1944), and *Bluefield Waterworks & Imp. Co. v. Public Serv. Comm'n of W. Va.*, 262 U.S. 679, 67 L. Ed. 1176 (1923). Under *Hope* and *Bluefield*, "the allowed return should be commensurate with returns on investments in other firms of comparable risk. A proxy group of similarly situated companies of comparable risk is needed to meet this criteria." *Hope*, 320 U.S. at 603, 88 L. Ed. at 345. The ROE should "be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Id.* However, the Company "has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures." *Bluefield*, 262 U.S. at 692-93; 67 L. Ed. at 1883. This determination necessarily "depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts." *Id.* at 692; 67 L. Ed. at 1882.

That said, "the Commission [is] not bound to the use of any single formula or combination of formulae in determining rates." *Hope*, 320 U.S. at 602, 88 L. Ed. at 345. As this Commission has stated previously:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return,

> but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management . . . . In reality, the concept of a fair rate of return represents a "zone of reasonableness."

Order Approving Revenue Requirement, Rate Schedules and Notice to Customers of Change in Rates, *Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges*, No. E-2, Sub 1300, 155 (N.C.U.C. August 18, 2023) (2022 DEP Rate Case Order) (citations omitted).

The AGO agrees with the Public Staff's recommendation at the hearing and suggests that the Commission adopt an ROE of 9.35%. The evidence offered in the proceeding shows that a 9.35% ROE is sufficient and fairly balances the interests of investors and consumers. This recommendation is also supported by the expert testimonies of Public Staff witness Walters, CUCA witness LaConte, Commercial Group witness Chriss, NCJC *et al.* witness Ellis,[1] and CIGFUR witness Collins. Indeed, the only outliers are Duke's witnesses.

Our Supreme Court has also concluded that it is not proper to give weight to such other returns determined in regulatory proceedings, since the details underlying those determinations are not of record. *State ex rel. Utils. Comm'n v. Public Staff*, 331 N.C. 215, 224-25, 415 S.E.2d 354, 360-61 (1992); *see also Cooper*, 367 N.C. at 443, 758 S.E.2d at 643. For example, in 1992, the North Carolina Supreme Court overturned this Commission's order regarding the ROE fixed for Duke Power in part because the Commission gave weight to ROE

[1] Although this witness recommended an ROE of 6.15%, he also recommended a corresponding, and significant, increase to the common equity ratio of capital structure to 58.8%.

decisions by other regulatory authorities. *Public Staff,* 331 N.C. at 225, 415 S.E.2d at 361. The Court found that the decisions by other regulatory authorities "fail[ed] to support the Commission's findings because there is nothing in the record to show that the equity return requirement for any of these utilities is comparable to Duke's." *Id.* Similarly, in 2014, the North Carolina Supreme Court reversed and remanded an order of this Commission on ROE and concluded that "the Commission's reliance on past ROE determinations authorized for other utilities, without evidence tying those determinations to the facts of the case *sub judice*, prevented the Commission from fairly considering current economic conditions." *Cooper*, 367 N.C. at 443, 758 S.E.2d at 643.

A key point of disagreement in this proceeding is how the modernized ratemaking mechanisms under House Bill 951 will impact the risk to the Company. N.C.G.S. § 62-133.16(c)(1)(a) recognizes that the approval of an MYRP may affect the utility's risk and requires that "[i]n setting the electric public utility's authorized rate of return on equity for an MYRP period, the Commission shall consider any increased or decreased risk to either the electric public utility or its ratepayers that may result from having an approved MYRP." The Company argues that it is not proper to adjust the authorized ROE to reflect a decrease in risk due to these mechanisms. In support of its position, the Company claims that any decreased risk is "baked in" to the proxy group identified by Company witness Morin. However, few of the members of the Company's proposed proxy group are comparable to Duke insofar as they have alternative ratemaking mechanisms and are also vertically integrated utilities. None overlap specifically with each of the mechanisms Duke is proposing to adopt in this rate case. Indeed, only four members have both a multiyear rate plan and revenue decoupling: Edison International, Eversource Energy, Sempra Energy, and Xcel Energy.

It is axiomatic that a shift from traditional ratemaking principles to these new-to-North Carolina constructs minimizes risk. The MYRP allows multiple years of rate adjustments based only on projected costs and revenue requirements, with the Company better able to adjust and absorb changes in expenditures and operating conditions during each rate year of the plan, all while improving cash flow during construction of planned and Commission-approved projects. Moreover, these investments are immediately placed into rates—without further consideration of other factors that would necessarily mitigate the future rate increase, such as additional load growth or cost efficiencies.

Going forward, instead of recovering expenses only once capital projects are completed and in service, Duke collects these rates prior to completion, and without the time lag, expense, and natural check on capital spending inherent in a future rate case. It also places additional risk on customers for bearing costs for projected projects that are never completed on the hope that the costs associated with the failed projects will be removed in future cases or not be attributed elsewhere. Duke will earn a return on capital investment several years earlier than it would be able to with traditional ratemaking with incommensurate benefit flowing to ratepayers, so long as Duke's overall performance falls within a certain band. It also shifts the burden and risk onto intervenors and the Commission to claw back from Duke what has already been given.

Public Staff witness Walters testified that the implementation of PBR would further transfer the risk from shareholders to ratepayers due to the substantial mitigation of regulatory lag. As a result, witness Walters testified that if the Commission were to approve the requested MYRP and PBR, the approved ROE should be adjusted downward 20-basis points to 9.35%, instead of 9.55% which he recommends as appropriate in the absence of these risk mitigation measures.

Duke's own expert, Dr. Morin, agreed that risk-mitigating mechanisms reduce risk on an absolute basis. (Tr. vol. 7, 298) He also testified that the risk-reducing nature of performance-based regulation generally warrants a downward adjustment in ROE. (*Id*. at 297-98) Likewise, CUCA witness LaConte and Public Staff witness Walters both testified that a 20-basis-point reduction would be appropriate on the approval of the MYRP and PBR, due to the Company's lower risk profile. However, witness Morin believes that because several companies in his proxy group employ various risk-mitigating mechanisms such as revenue decoupling, riders, adjustment clauses, MYRPs, and PBRs, the reduced risk is already considered and embedded in the financial data (*Id.*)—as if all risk-mitigating mechanisms are created equal in their impact to a utility's risk. This argument is flawed.

An MYRP allows three full years of rate adjustments based on projected costs and projected revenue requirement levels. Most other risk mitigation mechanisms do not target and absorb large, projected, future capital projects—especially to the degree as proposed here—giving money to the utility before it has even been spent. Rather, they mostly are expenditure-specific, like fuel adjustment clauses, which are simply passthroughs that do not command investor return, or decoupling mechanisms associated with lost revenues due to energy efficiency or customer-owned distributed generation, of which currently makes up a small portion of utility revenues. Indeed, Duke already also employs several of these other measures, including various riders, fuel adjustment clauses, and deferral accounting treatment for large expenditures.

In contrast, Duke failed to show that each company in its proxy group has adopted, or intends to adopt, each and every one of the risk-reducing mechanisms at issue in this case: PBR, MYRP, and revenue decoupling, coupled with the additional authorization for the utility to permissibly *overearn* so long as its overearning falls within a certain band. Each of these mechanisms reduces both absolute and relative risk. Similarly, the other factors that "work in the reverse direction—e.g., "declining customer energy usage, improving energy efficiency technologies, [and] the advent of game-changing distributed generation" (*Id.* at 299)—are minimized by the decoupling Duke seeks.

The Commission cannot conclude that because *some* risk-mitigating mechanisms are available and utilized in some states, that these other mechanisms are akin to the implementation of PBR and MYRP or that all the proxy companies presumably have commensurate risk profiles to DEC. Other regulatory commissions have recognized the significant impact of multi-year rate regulatory treatment on reducing the adopted ROE for regulated utilities. A notable instance is the recent 2021 decision by the Public Service Commission of the District of Columbia (PSCDC), which decreased the proposed ROE for Potomac Electric

Power Company to reflect the diminished risk associated with its Enhanced Modified Rate Plan. In The Matter of the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan, 2021 D.C. PUC LEXIS 77, *7, *112, *117 (D.C.P.U.C. June 8, 2021) (concluding that "the Modified EMRP reduces the ROE from 9.7% to 9.275% accounting for the reduction in risk and regulatory lag which further reduces the revenue requirement and benefits all ratepayers"). The PSCDC further commented that investors generally hold a positive view on the impact of an MYRP on a utility's cash flow. *Id.* at *179-80.

A recommended 9.35% ROE is in line with all witness testimony aside from the Company's. Public Staff witness Walters recommended 9.35%; CUCA witness LaConte recommended 9.20%; and NCJC *et al.* witness Ellis recommended a ROE of 6.0%, compensated by recommending approval of a significantly higher equity ratio of 58.8%. In contrast, Duke witnesses Morin's and Coyne's recommended ROE of 10.4% is at least 70 basis points higher than the national average and 80 basis points higher than the Company's current authorized ROE of 9.60%. (*See* Tr. vol. 15, 1015 ("According to data from S&P Global Market Intelligence ('S&P Global'), a financial news and reporting company, the average of the 148 reported electric utility rate case ROEs authorized by commissions to investor-owned utilities in 2019, 2020, 2021, 2022, and so far in 2023, is 9.49 percent."; *Id.* at 1016 ("So far in 2023 [it] is 9.70 percent."); Tr. vol. 7, 305 ("which averaged 9.73% so far in 2023"); *see also* Commercial Group witness Chriss Exhibit 2)

It is apparent that Duke will be expending substantial sums and its creditworthiness is therefore important. However, there has been no persuasive evidence that Duke's credit rating is at any legitimate risk. Duke has presented no evidence that it lacks the ability to pay the expenses it will incur over the next many years. In fact it has stated that it does not intend to issue stock for the next three or four years. And it suffered no downgrade in the wake of the last rate case, despite this Commission's approving significant grid improvement expenditures and that case following in the wake of costly and significant coal ash litigation which resulted in the subsequent—again costly—coal ash settlement. Moreover, following the issuance of this Commission's Order in the Duke Energy Progress, LLC (DEP) Rate Case, which issued the week before the hearing for this case, Duke's sister company saw no downgrade and the outcome in that case was generally greeted favorably by the investor community. This was so despite DEP being awarded a 9.80% ROE—60 basis points lower than its initial request.

Relatedly, Duke in this case also seeks an upward adjustment in the common equity portion of its capital structure from its current common equity/debt ratio of 52/48% on the same basis it argues for a 10.4% ROE—threats to its creditworthiness. Yet Duke's current allowed common equity ratio already exceeds the nationwide average per S&P Global Market Intelligence by 116 basis points (data through June 9, 2023) (Tr. vol. 14, 23) There is also no evidence that Duke's parent company has had difficulty raising capital even though it maintains a lower equity ratio than 50%; to the contrary. In short, there has been no convincing evidence presented that Duke's financial outlook is at risk.

The Company itself has recognized that the PBR framework will help strengthen its financial outlook. For example, the Company has noted that "the proposed MYRP would result in more timely rate increases, and revenue decoupling reduces the risk of residential revenue erosion and volatility." (Tr. vol. 11, 149) The Company has noted that "about 90% of its electric capital investments are 'eligible for modern recovery mechanisms, mitigating regulatory lag.'" (Tr. vol. 14, 94-95) The earning sharing mechanism allows the Company to earn approximately $40 million in additional annual revenue before sharing them with ratepayers. This is on top of the tens of millions of additional dollars that would flow from ratepayers to shareholders were this Commission to approve Duke's requested change to its capital structure.

Industry analysts also agree that PBR will strengthen the Company's financial outlook. For example, S&P Global Ratings noted that both multiyear rate plans and decoupling help protect the Company from regulatory lag. (*Id.* at 94) This is in line with how credit rating agencies have addressed these regulatory mechanisms in other jurisdictions. S&P Global Ratings has stated that MYRP "supports credit quality" by "enhanc[ing] rate predictability, reduc[ing] regulatory lag, and provid[ing[an opportunity for [a] company to earn its authorized return." *(Id.)*

The Company argues that projected increases in interest rates, inflationary increases in O&M expenses and spending not related to the discrete MYRP projects will not be included in the MYRP-related revenue increase and therefore necessarily increase the risk to the utility. This is not the case. Under N.C.G.S. §

62-133.16, the utility may initiate a new rate case any time its earnings fall below those approved by the Commission. Therefore, those theoretical risks should have no bearing on the risk analysis because if they occur and actual earning erosion occurs, the Company can simply initiate a new rate case. Moreover, these risks are no different than those existing in any traditional ratemaking context.

The Company has implied that carbon reductions and the transition to cleaner energy are risks that the Company faces that are somehow specific to North Carolina. That is simply not so. The Commission need only look north to Virginia, or several other states located within PJM Interconnection LLC, to reject this claim. And it is the norm, not the exception, that States are seeking a cleaner energy future—almost every State in the nation is having these conversations, weighing resource options, and looking to make grid improvements to allow for clean energy. FERC issued Order No. 2023 on July 28, 2023, its final rule in FERC Docket No. RM22-14, opened in large part to address transmission grid reform and modernization to help facilitate this transition nationwide. *See Improvements to Generator Interconnection Procedures and Agreements,* 184 FERC ¶ 61,054, 2023 FERC LEXIS 1012 (2023). Duke not only has the assurance of the Carbon Plan statute it now has the assurance and assistance of the statutory PBR/MYRP framework to help effectuate these changes. Duke has not pointed to any increased risk of it or other North Carolina utilities failing to recover costs when those costs are associated with specific statutory authority mandating or permitting the actions and improvements be taken. Indeed, the Company acknowledges that *failure* to transition away from carbon intensive generation is a major risk. (Tr. vol.

7, 63-64 ("The voices of our customers and our investors have become increasingly clear on this topic—they expect us to invest in cleaner power and we are making decisions and building long-term plans based on those expectations."))

Finally, if there is no lessened risk—or commensurate benefit—that necessarily passes to ratepayers that is inherent to the adoption or approval of the MYRP, PBR, and revenue decoupling mechanisms, it is unclear why then the Commission should approve these measures. Traditional rate making principles have historically well served shareholders and ratepayers alike. If ratepayers are not to see some additional benefit—commensurate with the benefit that will be seen by the Company and its shareholders—how can it be said that moving to these constructs is in the public interest? *See* N.C.G.S. § 62-133.16(d)(1) (which provides that the Commission may approve a PBR application "only upon a finding that a proposed PBR would result in just and reasonable rates, *is in the public interest*, and is consistent with the criteria established in this section and rules adopted thereunder") (emphasis added). This is especially so when Duke's as-proposed PIMs are, and as further discussed below, "underwhelming" at best. Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, *Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges*, No. E-2, Sub 1300, 2023 N.C. PUC LEXIS 1093, *575 (N.C.U.C. August 18, 2023) (Commissioner Clodfelter, dissenting in part) (2022 DEP Rate Case Order).

The evidence in the record shows that a 9.35% ROE strikes a fair and reasonable balance between the interests of the Company and its shareholders and ratepayers for each rate year for the term of the proposed MYRP. The Commission should approve the same.

II. THE COMPANY'S PROPOSAL TO INCLUDE HAZARD TREE REMOVAL AS AN MYRP PROJECT SHOULD BE REJECTED BECAUSE VEGETATION MANAGEMENT IS NOT A CAPITAL PROJECT OR INVESTMENT.

The Company identifies $39 million in Hazard Tree Removal Projects that it seeks to include in its MYRP project proposal. (Tr. vol. 8, 108-09, 130) The capital costs the Company seeks for the Hazard Tree Removal Program are $71.6 million. (Tr. vol. 8, 135) Duke explains that the program "maintains or improves reliability by identifying and cutting down dead, structurally unsound, dying, diseased, leaning, or otherwise defective trees from outside the maintained right of way that could strike electrical lines or equipment of the distribution system." (Tr. vol. 8, 135) It further identifies these projects as outside of "the scope of [its proposed] Substation and Line projects." (*Id.* at 131) Instead the Company states that this work "is performed in conjunction with normal trimming cycles." (*Id.* at 108-09)

Two categories of expenditures may be captured in rates: those that make up a utility's rate base, and those that make up its operating and maintenance expenses. *See, e.g., State ex rel. Utilities Com. v. Thornburg (Thornburg I)*, 325 N.C. 463, 467 n.2, 385 S.E.2d 451, 453 n.2 (1989); *see also* N.C.G.S. § 62-133(b). Our Supreme Court has noted that "[t]here is but one ratebase, namely, the ratebase defined by the ratemaking statute." *State ex rel. Utilities Com. v. Morgan*, 277 N.C. 255, 268, 177 S.E.2d 405, 414 (1970); *see also State ex rel. Utilities Com. v. Thornburg (Thornburg II),* 325 N.C. 484, 491, 385 S.E.2d 463, 466-67 (1989). Only the utility's rate base, not its operating expenses, is eligible to be multiplied by a rate of return. *Thornburg I*, 325 N.C. at 475, 385 S.E.2d at 458; *see also* N.C.G.S. § 62-133(b)(5).

The discretion granted to the Commission by N.C.G.S. § 62-133(d) is not so broad that it allows the Commission to ignore specific requirements in the ratemaking formula. North Carolina law makes clear that the Commission has no discretion to give rate-base treatment to something that is not properly includable in rate base. *See, e.g., State ex rel. Utilities Com. v. Carolina Water Serv.*, 335 N.C. 493, 507-08, 439 S.E.2d 127, 135 (1994); *Thornburg II*, 325 N.C. at 486, 385 S.E.2d at 464. The Commission also does not have the discretion to expand a utility's rate base simply because some parties agree to it in a settlement (or because the expenses were erroneously capitalized in past cases).

North America Electric Reliability Corporation's (NERC's) Electric Reliability Standard FAC-003-4[2] requires that trees or other vegetation growing in *or adjacent to* the transmission line right-of-way be regularly removed or pruned in order to prevent power outages caused by contact with a transmission line. Duke's own Vegetation Management Policy recognizes and relies upon the same to hold true for distribution lines. *See* Duke Energy Carolinas, LLC's Vegetation Management Policies and Practices, No. E-7, Sub 1014 (filed December 14, 2015).[3] Title 18, Chapter I, Subchapter C, Part 101—FERC's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the

[2] https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf; *see also* Up in Flames: Containing Wildfire Liability for Utilities in the West, 33 Tul. Envtl. L.J. 55, 82 fn.151 (2020) ("NERC, through its delegated powers from the Federal Regulatory Commission, sets the standard minimum clearance between vegetation and powerlines and other inspection requirements.").

[3] https://starw1.ncuc.gov/ncuc/ViewFile.aspx?NET2022&Id=b4860b7f-36aa-42ba-9730 2ba6f4eeed90

Federal Power Act—permits the cost of labor, materials used, and expenses incurred for trimming trees and clearing brush (or chemically treating the right of way when occurring subsequent to the construction of the line) to be included as operating expenses. *See* 18 C.F.R. Part 101, Accounts 571, 574, 593, and 594.1; *see also* Tr. vol. 12, 889 ("the vegetation management pro forma is for expenses and not capital projects").

Duke attempts to include what is essentially vegetation management as a capital project warranting a return, rather than as annual operations and maintenance (O&M) expense. But the "project" activities are simply part of "the Company's overall vegetation management approach"—"[t]he work is no different than what we've been doing for years." (Tr. vol. 8, 116, 417; *see also id.* at 417-18 ("no different than hazard trees we're doing right now that are not part of MYRP," "it's routine"); *Id.* at 351 (witness Maley responding to Public Staff's request to remove vegetation management costs from the MYRP, in part stating "the VM Project locations are considered routine work . . .")) To be sure, vegetation management is important for overall system reliability and benefits customers (Tr. vol. 8, 117), much like regular oil changes are important to maintain and keep reliable a gasoline-powered engine and can prevent more costly issues from arising. But that fact does not transform a regular maintenance expense into a capital asset warranting a return.[4]

Duke's argument fails as a matter of law. It is identical to DTE Electric Company's (DTE) argument before the Michigan Public Service Commission

[4] Like it did for other projects, the Company did not prepare cost-benefit analyses for its alleged Hazard Tree Projects. (Tr. vol. 8, 143)

(Michigan PSC), that some $45 million in annual expenses as part of its "Enhanced Vegetation Management Program" (EVMP) warranted capital treatment. *See Order on Application of DTE Electric Company for Authority to Increase its Rates*, 2016 Mich. PSC LEXIS 23, *11-*13 (M.P.S.C. January 19, 2016). In rejecting the claim, the Michigan PSC upheld the ALJ's Order which held that "the Commission is not presently convinced that this program is fundamentally different from enhanced clearing, the costs of which have never been capitalized. The EVMP effort is not a first clearing, as all of these rights-of-way have been cleared before, possibly multiple times." *Id.* at *11. The Michigan PSC also noted that reliability would be improved but nevertheless disallowed the capitalization request. In fact, the Michigan PSC *disallowed recovery of the $27 million* DTE had already spent, noting that it would not "reclassify [that amount] the utility chose to spend without Commission approval." *Id.* at 13. On appeal, the Michigan Court of Appeals affirmed the same. *See Application of DTE Electric Co to Increase Rates*, 2018 Mich. App. LEXIS 263 (Mich. Ct. App. February 13, 2018) (unpublished).

The Michigan PSC subsequently rejected another utility's attempts at the same, addressing Indiana Michigan Power Company's (I&M) attempt to capitalize its own expanded vegetation management program. *See Order on Application of I&M for Authority to Increase its Rates*, 2018 Mich. PSC LEXIS 97 (M.P.S.C. Apr 12, 2018). There, I&M sought to move to a four-year management cycle and argued that clearance zone widening and a move to a quicker cycle-based vegetation management program would increase reliability and further benefit customers, including by providing savings related to reduced outages. *Id.* at *25-

*26. While I&M agreed that any future widening would be an O&M expense, it sought to capitalize the "initial" widening to the expanded "clearance zone." The Michigan PSC noted that

> according to a 2013 Federal Energy Regulatory Commission (FERC) audit report, "the capitalizable costs of equipment," which "include the first clearing and grading of land and ROW [right of way], only applies to the vegetation management costs incurred for the initial clearing of land during construction. Vegetation management costs that a Company incurs subsequent to the construction phase of a project should be an O&M expense."

Id. at *27; *see also id.* at *30 (the Michigan PSC citing and relying upon the report); *accord Fin. Accounting, Reporting and Records Retention Requirements*, 117 F.E.R.C. ¶ 61,064, 2006 FERC LEXIS 2535, *236 (2006) (the "first clearing and grading of land and rights-of-way and the damage costs associated with the construction and installation of property" are "included in the appropriate property accounts directly benefited").

In again rejecting the claim, the Michigan PSC concluded that "I&M's proposed vegetation management program is properly treated as an O&M expense[,]" further noting that

> [t]he company's proposed "clearance zone" is not a first clearing because all these ROWs have been cleared before, possibly multiple times. In addition, the costs incurred to expand the ROW are no longer associated with the first clearing and grading of land during initial line construction. Therefore, going forward, any vegetation management costs the company incurs to maintain or enhance a previously-cleared zone should be treated as an O&M expense with no impact to previously-capitalized vegetation management expenses.

Id. at *30-*31.

This Commission has likewise previously referenced Duke's vegetation management as ordinary expenses. *See, e.g.,* Order Accepting Stipulation, Deciding Contested Issues, And Requiring Revenue Reduction, *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges*, No. E-7, Sub 1146, 28, 104 (N.C.U.C. June 22, 2018) (2018 DEC Rate Order); *cf.* Order Granting Partial Rate Increase, *Application of Public Service Company of North Carolina, Inc., for an Adjustment of its Rates and Charges*, No. G-5, Sub 327, 20-23 (N.C.U.C. October 7, 1994) (clean-up costs recoverable only as reasonable operating expenses as a matter of law).

Other courts and commissions have treated regular or routine vegetation maintenance similarly. *See State ex rel. Mo. Power & Light Co. v. Pub. Serv. Comm'n*, 669 S.W.2d 941, 944-45 (Mo. App. 1984) (holding that tree trimming expenses are expenses properly included in the revenue requirement); *see also Empire Dist. Elec. Co. v. Pub. Serv. Comm'n*, 630 S.W.3d 887, 892 (Mo. App. 2021) (state commission treating vegetation maintenance as an expense); *Reliant Energy, Inc. v. Public Util. Comm'n*, 153 S.W.3d 174, 202 (Tex. 2004) (same); *accord Sherwood v. TVA*, 956 F. Supp. 2d 856, 865-66 (E.D. Tenn. 2013) (same); *In re Consumers Energy Co.*, 2012 Mich. App. LEXIS 2195, *17-*18 (Mich. App. 2012) (same). Unlike, for example, securitization of storm costs (to include vegetation management costs related to the storm), these expenses are not related to a specific extreme or unprecedented weather event. Neither has Duke sought to capitalize, securitize, or defer these as past-incurred extraordinary or unique costs; nor has it sought to meet the Commission's requirements for deferral and capitalization. *See, e.g., Elyria Foundry Co. v. Pub. Util. Comm*., 114 Ohio St.3d 305, 308-10 (Ohio 2007) (Ohio PUC permitting the capitalization and deferral of vegetation management expenses incurred as storm costs).

Nor are these trees "projects," capital assets, or investments in any sense of the word(s). The Project or Program—Duke uses these terms interchangeably—is not tree-, location-, or project-specific. (Tr. vol. 8, 415; Tr. vol. 14, 262) Duke fails to sufficiently identify any particular hazardous tree set for one-and-done removal in a certain future Rate Year that is the action item considered to be the specific MYRP project that warrants inclusion in that Rate Year—e.g., akin to a one-time transmission line upgrade that is placed into service and, upon review, may support a conclusion of property used and useful and placed into service. Duke cannot even give a rough estimate of tree counts or specific locations. Although, of course, there are many times specific trees reported to the Company that are placed in a queue for removal, Duke is instead relying on future estimates based on the continuing expense of removing hazardous trees in general. (Tr. vol. 8, 414-15; *see also id.* at 417-19) One cannot create rate base simply by lumping together a bunch of estimated future maintenance expenses and calling it a "project."

Even were Duke to identify and log each-and-every tree with sufficient detail, it would still fail its burden. Essentially, the program is one aspect of regular maintenance but relies on customers (or workers in the field) to discover and alert the company to certain hazardous trees that either Duke failed to identify and remove in its last 5/7/9-year cycle or may have become hazardous in the (potentially upwards of) 9 years since Duke last visited the right-of-way. Neither of these circumstances warrants capitalization. In short, the fact that the Company has a plan for right-of-way maintenance based upon the identification of certain hazard trees through customer (or employee) reporting is not compelling. The Company could not capitalize *all* its vegetation management expenses merely by first identifying and then making a record of each tree, bush, and shrub it considered a hazard prior to its future pruning of the vegetation in the field; it cannot do so by relying on customer involvement to identify the same.

Duke admits that its Hazard Tree Removal Program is not the exercise of condemnation proceedings or the negotiating to buy or otherwise acquiring adjacent customers' property. (Tr. vol. 8, 118; *see also* Tr. vol. 14, 250-51) Again, "it's essentially a larger scale tree trimming program that works in tandem with the traditional vegetation management expenses." (Tr. vol. 14, 250) In other words, it is not the purchase of additional property or the expansion of right-of-way—a capital asset or investment that may well constitute property used and useful. Nevertheless, to the extent it is, Duke has not separated out any such claim and thus cannot include or recover these funds as though it were intending to purchase, or had already purchased, such land.

More problematically, the evidence also shows additional overlap between what Duke considers its ordinary vegetation management and its hazard tree programs. The Company states that its costs are currently higher than reflected in the Distribution Vegetation Management production budget and threatens that any reduction—as initially recommended by the Public Staff—"will further challenge the Company's efforts to trim the full 5.7.9-year mileage target of approximately 6,055 miles per year." (Tr. vol. 8, 179, 200; *see also id.* at 249 ("will prevent" the same)). The Company further threatens that "[d]ecreasing the funding DEC proposed in the MYRP will limit its ability to remove hazard trees, which will, in turn, contribute to vegetation-caused outages." (*Id.* at 226) In other words, the Company links its ability (and obligation) to properly trim 6,055 miles annually with additional costs for hazard tree removal—one budget affects the other. They are in essence the same maintenance program sharing costs.

This overlap is also problematic for a different reason. As this Commission is well-aware, the Company has a history of failing to regularly maintain its right-of-way. *See* 2018 DEC Rate Order at 104 (noting DEC's 13,467-mile tree-trimming backlog). That history created a backlog that specifically needed to be addressed by this Commission; the Company only caught up over numerous years and with the imposition of additional Commission oversight. *See* Order Declining to Accept Annual Vegetation Management Report and Requiring Compliance Filing, No. E-7, Sub 1146, 3-4 (N.C.U.C. June 18, 2019) (noting that Duke missed its target miles, failing to "understand why [Duke's] strategy necessarily result[ed] in [its] falling behind" on its obligation, and "seek[ing] DEC's confirmation" that it will spend the necessary funds to catch-up); see also Order on Revised Vegetation Management Plan, No. E-7, Sub 1146 (N.C.U.C. August 15, 2019). Providing a return would only incentivize less than diligent 5/7/9-year vegetation management practices, necessitating (and with the Company further profiting from any) future trips to remove hazardous trees.

The Program also cannot be included as a capital asset for another reason. Because it is an annual expense based on past work and estimations of future budgetary-needs for the same or similar maintenance work, the Program is in essence either (1) not property that is currently used and useful, or (2) it is never finished.[5] Once a specific tree is removed, that tree cannot be said to be property that is placed into service or used and useful in continuing to provide service to the public. *See Thornburg I*, 325 N.C. at 471, 385 S.E.2d at 455-56 (reversing Commission decision to place canceled plant into rate base); *Carolina Water*, 335 N.C. at 507-08, 439 S.E.2d at 135 (1994) (same as to retired plant); *State ex rel. Utilities Com. v. Public Staff*, 333 N.C.195, 202, 424 S.E.2d 133, 137 (1993) (same with water connection). Likewise, if the project is couched as a continuing program without any particular end date, then it can never be finished or placed into service. *Morgan*, 277 N.C. at 273, 177 S.E.2d at 417. Either way, it cannot be capitalized as rate base.

Any costs associated with tree removal should be removed from Duke's MYRP project proposal. It also does not appear that Duke has alternatively requested to treat these costs as ordinary, dollar-for-dollar recoupable expenses as part of its test year. As such, the Commission should not allow these expenses at all.

[5] Any arguments to the contrary would essentially apply to all vegetation management operations, as well as all other operations and maintenance activities performed by the Company.

III. THE COMPANY SHOULD NOT BE ALLOWED TO EXCLUDE REVENUES RELATED TO ELECTRIC VEHICLES FROM THE DECOUPLING MECHANISM UNTIL THEY CAN BE ACCURATELY MEASURED.

The Company has proposed a Residential Decoupling Mechanism that allows DEC to earn a consistent revenue-per-customer as residential electricity consumption rises or falls. (Tr. vol. 11, 146) This mechanism breaks the link between Company revenues and residential electricity consumption, thus allowing the Company to no longer be disincentivized to encourage energy conservation. (*Id.*) However, as the Company recognized, residential decoupling reduces the Company's throughput incentive, which is one of the incentives that causes utilities to encourage increased energy consumption, such as adoption of electric vehicles (EVs). (Tr. vol. 11, 146-47) Recognizing the value of EVs and wanting electric public utilities to be friendly to their adoption, N.C.G.S. § 62-133.16(c)(2) allows the Company to "exclude rate schedules or riders for electric vehicle charging, including EV charging during off-peak periods on time-of-use rates, from the decoupling mechanism[.]"

The Company has proposed a method for excluding EV revenues from the residential decoupling mechanism "in order to continue to incent adoption of EVs." (Tr. vol. 11, 147) Every month, the Company will calculate the difference between the target per-customer revenues and actual residential revenues. (Tr. vol. 11 p 146-47) The Company will then adjust to account for Demand-Side Management/Energy Efficiency ("DSM/EE") net lost revenues and incremental electric vehicle ("EV") revenues. (Tr. vol. 11, 147) The remaining amount will accrue a return for the Company based on the Company's after-tax weighted average cost of capital (WACC). Any amount remaining at the end of the rate year will be returned to ratepayers or recovered by the Company through a decoupling rider in subsequent rate years. (*Id.*)

The Commission is permitted to "exclude rate schedules or riders for electric vehicle charging, including EV charging during off-peak periods on time-of-use rates, from the decoupling mechanism to preserve the electric public utility's incentive to encourage electric vehicle adoption" under N.C.G.S. § 62-133.16(c)(2) (stating that the utility "may" exclude those schedules). However, the Commission is not required to do so. N.C.G.S. § 62-133.16(c) states that the Company "may exclude" EV revenues. "The word 'may,' when used in a statute, is generally construed as permissive rather than mandatory." *Wise v. Harrington Grove Comm. Ass'n, Inc.*, 357 N.C. 396, 403, 584 S.E.2d 731, 737 (2003). Therefore, the statute gives the utility the option to seek exclusion of EV revenues, but neither requires it to do so nor guarantees the Commission's approval. The Company still has the burden of proving that doing so is "just and reasonable."

The Company repeatedly points to the need to preserve or strengthen "the Company's incentive to encourage EVs." (Tr. vol. 11, 154) However, the Company has pointed to no actions that it has taken to encourage EV adoption. Instead, the Company's proposed EV revenue exclusion is an attempt to insulate EV revenues without any identifiable benefit to ratepayers. Compare this with the DSM/EE mechanism, which requires the Company to carefully assess its role in and contribution towards DSM/EE adoption and only recover net lost revenues specifically related to its programs. (Tr. vol. 15, 407)

A. <u>The Company's proposed method of calculating EV revenues is inconsistent with N.C.G.S. § 62-133.16(c)(2) and Commission Rule 1-17B.</u>

The Company's proposed method for estimated EV revenues to be excluded from the residential decoupling mechanism includes a three-step process, which is described below in Section I.B. in more detail. The Company, the Public Staff, and CIGFUR III have committed to "work together to develop and file EV tariffs and/or programs to estimate and update the revenue associated with residential EV sales in the Company's service territory[.]" (PIM Settlement at 7) Until that development is complete, and the results are evaluated, the three-step method outlined in the Company's initial application will be used. The only justification given in the testimony supporting the PIM Settlement was:

> The conditions associated with tracking and estimating the Company's proposal to exclude incremental residential EV sales from the Decoupling Mechanism are reasonable and will result in a transparent process for updating EV revenue estimates before the Commission.

(Tr. vol. 11, 209)

At the outset, this proposed approach is plainly inconsistent with the statutory language of N.C.G.S. § 62-133.16(c)(2), which allows for the exclusion of "rate schedules or riders for electric vehicle charging[.]" The Company's proposal does not identify rate schedules or riders specific to electric vehicle charging.

Similarly, Commission Rule R1-17B(d)(1)(f) requires that a decoupling ratemaking mechanism include:

> A method for distinguishing kWh sales associated with EVs and the residential class as a whole and an explanation of how those EV sales will be treated, including the EV rate schedules or riders that

> have been excluded from the mechanism, along with the projected number of EV customers and kWh for each month of each Rate Year, along with the electric public utility's underlying assumptions, calculations, and methodology.

The Company argues that its method for estimating EV revenues is the same as a "method for distinguishing" those revenues. This analysis is flawed—distinguishing and estimating are not synonymous. Distinguish means "to perceive a difference in." Merriam-Webster.com Dictionary, Merriam-Webster (2023). Conversely, estimate means "to determine roughly the size, extent, or nature of." *Id.* Both the PBR statute and the Commission's rules require that EV revenues be specifically measured before their exclusion is allowed.

The General Assembly authorized the Company to exclude EV revenues from the decoupling mechanism under one condition: they prove the magnitude of those EV revenues. The Company has not and cannot do so. Until the Company establishes a method for distinguishing EV revenues from other residential revenues, the Commission's rules and the PBR statute prohibit their exclusion. The burden of proof is on the Company to prove that its rates are just and reasonable.

B. <u>The Company's proposed method of estimating electric vehicle revenues is inaccurate by an incalculable degree.</u>

As described above, the Company's proposed method for estimating EV revenues, which was adopted in the PIM Settlement with minor adjustments, is composed of three steps. Each of these steps requires approximations, estimations, and guesses. The Company cannot and will not be able to verify the accuracy of this estimate. Public Staff witness Nader referred to the process as "highly speculative." (Tr. vol. 12, 774)

The first step involved in the EV revenue exclusion is estimating the incremental number of residential EVs in the Company's service territory. (Tr. vol. 12, 105) Under the Company's initial application, the Company proposed using data from the Electric Power Research Institute (EPRI) to determine the number of residential EVs in the Company's service territory. (*Id.*) After other parties critiqued this approach, the Company agreed to use data from the North Carolina Division of Motor Vehicles (DMV) to estimate the number of residential EVs. (Tr. vol. 12, 123) Public Staff witness Nader noted that monthly EV registrations are "also estimations rather than verified numbers." (Tr. vol. 12, 774) The DMV data that the Company intends to use is only available on a county-wide basis. (Tr. vol. 15, 402) Further, even though the decoupling mechanism is limited to the residential class, the DMV data does not differentiate between residential, commercial, and industrial vehicles. (*Id.*) Even if the Company can narrow the registrations to determine residential EVs within the service territory, which it has not described whether or how it would, the DMV data cannot show whether the EV registered in a given county is charged within that county, much less within the Company's service territory. (*Id.*) Together, these limitations mean that the number of residential EVs calculated under this method will not be accurate and it is not possible for the Company to determine the degree of inaccuracy.

The second step involved in the EV revenue exclusion is estimating the "typical" kWh usage data per EV. (Tr. vol. 12, 106) The Company's initial application called for this to be set at 225 kWh per EV. *(Id*. at 105) This number was based on the Company's application for the EV Make-Ready Program. *(Id.)*

In the PIM Settlement, the Company, the Public Staff, and CIGFUR III agreed to lower this estimate to 180 kWh as proposed by Public Staff witness Nader. (PIMs Settlement at 7)

The 180 kWh per EV figure is based on the first status report made by the Company and DEP in the Make Ready Credit Program. (Tr. vol. 15, 403) The Company's Make-Ready Credit Program has been available for less than one year. (*Id.*) During that time, only 508 residential credits have been fulfilled under the program. (*Id.*) This number reflects 1.3% of all EV users of EVs registered in North Carolina. (*Id.*) Company witnesses Byrd and Beveridge testified that the 180-kWh figure was "based on limited data and limited participation. (Tr. vol. 10, 224) Finally, the Company's First Status Report in the Make-Ready Credit Program states:

> The Companies are reviewing interval data from AMI meters to identify when customers may be charging their EVs. Currently, the MRC programs are still too early in implementation and the interval data is not granular enough to create reliable revenue estimates based on when EV charging is taking place, as opposed to other appliances being used. As the MRC programs progress and the Companies have more granular interval data from the AMI meters to review, they will be able to provide this analysis.

(*Duke First Status Report of Make Ready Credit Programs,* Nos. E-7, Sub 1195, and E-2, Sub 1197, at 11 (N.C.U.C. February 20, 2023); *see also* Tr. vol. 11, 774-75) Together, this evidence shows that the 180-kWh estimate is based on a miniscule sample size that may not be representative of typical EV users and includes EVs that are not eligible to be excluded under the residential decoupling mechanism. The extent of the inaccuracy is unknown and cannot be determined.

The third step involved in the EV revenue exclusion is to calculate EV revenues by multiplying the preceding two numbers by the estimated electric rate. (Tr. vol. 12, 105) In the Company's initial application, the Company proposed using an average of the off-peak rates from the RSTC and RETC rate schedules. (*Id.*) Public Staff witness Nader advocated using the Schedule RES rate until the Company demonstrates that most EV owners are charging during off-peak hours. (Tr. vol. 12, 775-76) Nevertheless, the PIM Settlement made no changes to this step. There is no evidence in the record to support that either of these rates constitute a reasonable estimate of actual residential EV charging.

The proposed method of estimating EV revenues is not based on actual data but is instead based on an inflexible calculation that uses a number of inaccurate assumptions. This means that not only will the estimated EV revenues be inaccurate, but the calculation will be "unable to account for changes in markets, policy changes, and energy prices." (Tr. vol. 15, 405)

C. <u>Allowing ratepayers to be billed based on inaccurate estimates is inconsistent with the Commission's prior practice.</u>

In other areas, the Commission has devised strict rules to ensure that ratepayers are only billed for electricity they actually use. For example, the Commission has rules regarding billing accuracy. N.C.G.S. § 62-139(a) prohibits any utility from "directly or indirectly, by any device whatsoever, charge, demand, collect or receive from any person a greater or less compensation for any service rendered or to be rendered by such public utility than that prescribed by the Commission[.]" Commission Rule R8-12 thus sets strict meter accuracy requirements. A finding that a utility violated Commission Rule R8-12 will result in an order directing the utility to refund the affected ratepayers. Similarly, Commission Rule R8-44 sets a method for compensating ratepayers who have been overcharged, including those who are “inadvertently” overcharged.

Similarly, the Commission requires that DSM/EE recovery be supported by Evaluation, Measurement, and Validation (EM&V). In order to recover costs for DSM/EE programs, Commission Rule R8-69(f)(iii) requires the Company to provide “a description of, the results of, and the costs of all measurement and verification activities conducted in the test period.” Together, these precedents show that the Commission has strictly maintained that ratepayers only be charged for services actually rendered by the Company. The Company’s method for estimating residential EV revenues is not comparably rigorous.

D. <u>The risks to ratepayers and the Company are not equivalent.</u>

The residential decoupling mechanism provides the Company with protection if its EV revenue calculations prove incorrect, but there is no similar protection for ratepayers. If the Company underestimates the revenues attributable to EVs, then any under recovery that causes the Company to fall below its revenue-per-customer target will be recovered via the decoupling mechanism. If the Company over-estimates the revenues from EVs, then there is no protection for ratepayers and an over-collection will occur. (Tr. vol. 15, 400-01)

The Company bears the burden of proof to show that its proposed rates are just and reasonable. Under this standard, the Company must “make an affirmative showing of the reasonableness of the costs in question” once an intervenor “adduces sufficient evidence to cast doubt upon their reasonableness or prudence.” *State ex rel. Utilities Comm’n v. Stein*, 375 N.C. 870, 908, 851 S.E.2d

237, 261 (2020).

> If a utility expense is properly challenged, the Commission has the obligation to test the reasonableness of such expenses. In addition, if there is an absence of data and information from which either the propriety of incurring the expense or the reasonableness of the cost can readily be determined, the Commission may require the utility to prove their propriety and reasonableness by affirmative evidence.

Id. (cleaned up). This standard does not require an intervenor to develop an alternative means of calculating the utility's rates or charges. As described above, there is an abundance of evidence in the record showing that the Company's EV revenue exclusion is unreasonable.

Public Staff witness Nader effectively concurs with the approach advocated for in this AGO post-hearing brief with his testimony that:

> Until such time as the Company is able to provide metered data for evaluation, measurement, and verification (EM&V) of EV sales, or the Company proposes specific rate schedules or riders for EV-related service, the "Incremental EV Revenue Adjustment" included in Taylor Exhibit 5 as proposed should be removed from the "Cumulative Deferral Balance" computation.

(Tr. vol. 12, 773-74) Therefore, the AGO recommends rejecting the proposed method for estimating EV revenues laid out in the PIM Settlement until the Company can accurately measure EV revenues.

IV. THE COMMISSION SHOULD CAP DECOUPLING SURCHARGES AT 3% ANNUALLY.

Under the proposed decoupling mechanism, if the Company's actual revenues-per-customer fall below the target revenue-per-customer, the Company will recover the difference through a surcharge in the following year. (Tr. vol. 11, 146-47)

The Commission should implement a 3% hard cap on decoupling surcharges. While annual increases under the MYRP are capped under N.C.G.S. § 62-133.16(c)(1)(a) at 4% of the utility's retail jurisdictional revenue requirement, there is no statutory cap on the decoupling surcharge. Under N.C.G.S. § 62-133.16(c)(1)(c)(1), the Commission is required to establish a decoupling rider within 60 days of the conclusion of each rate year. Public Staff witness Williamson expressed concern that "as the residential revenue requirement is reconciled annually through the decoupling mechanism, customers may see an increase in rates year over year, over and above the overall change in revenue requirement for years two and three of the MYRP[.]" (Tr. vol. 13, 53-54) A decoupling cap would help address these concerns.

N.C.G.S. § 62-133.16(d)(1) requires the Commission to ensure that the PBR application "[w]ill not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or 'rate shock' to customers." Without implementing a cap on decoupling surcharges, the Commission cannot ensure that future decoupling riders do not result in substantial increases in residential customers' rates.

The NERP Final Report called for the Commission to implement a decoupling surcharge cap. Company witness Bateman served as one of the co-leads of the NERP PBR Study Group and the NERP process informed the Company's application. (Tr. vol. 11, 160-62) One of the documents created by witness Bateman's study group was the PBR Regulatory Guidance, which contained "recommendations for the NCUC to consider if and when it begins a process to implement performance-based regulation." (Tr. vol. 11, 144 fn. 1 (available at https://deq.nc.gov/media/17684/download); *see also* Bateman Stillman Abernathy Rebuttal NCJC *et al.* Cross-Exhibit 1 (PBR Regulatory Guidance) at 2) Further, the PBR Study Group specifically called on the Commission to consider the conclusions reached by NERP. (*See, e.g.,* Tr. vol. 11, 164-66, 169, 187, 204; PBR Regulatory Guidance at 4) Similarly, Public Staff witnesses Thomas and Williamson testified that the "Public Staff is using the NERP as a foundation for our recommendations on PIMs and tracking metrics[.]" (Tr. vol. 14, 275) One of the PBR Study Group's key recommendations related to decoupling was that "[t]he amount of adjustment to customer rates under decoupling should be capped, and the design of refunds and surcharges should consider ways to encourage energy efficiency." (PBR Regulatory Guidance at 4, 14)

The Company argues that, if the Commission approves a decoupling cap, it should implement a soft cap, which allows any unrecovered amounts to be recovered in subsequent collection periods with a return. (Tr. vol. 16, 266) This change is inappropriate. Unlike a soft cap, "[a] hard cap would have the impact of limiting rate increases and promote cost containment." (Tr. vol. 15, 409) Further, it is unlikely that the Company will exceed the 3% cap. A 2013 study found that "almost two-thirds of adjustments made under decoupling were within 2% of the retail rate and 80% [of adjustments were] within 3%." (PBR Regulatory Guidance at 11) In addition, the hard cap further increases the Company's incentive to invest in energy efficiency and demand-side management. (Tr. vol. 15, 410) A hard cap incentivizes the Company to "operate efficiently and minimize wasteful spending." (*Id.*) Other Commissions have recognized that hard caps on decoupling surcharges are an important ratepayer protection. (*Id.*)

Discussing PIMs, the Company stated that it is important to take a "deliberate and conservative approach . . . in the initial years of PBR plans." (Tr. vol. 11, 187) This principle is no less important here where ratepayers may be negatively impacted.

V. THE COMMISSION SHOULD CEASE THE LOST REVENUE ADJUSTMENT MECHANISM FOR THE RESIDENTIAL CLASS IF RESIDENTIAL DECOUPLING IS APPROVED.

The Commission is required to approve an annual rider under N.C.G.S. § 62-133.9(d) to recover all "reasonable and prudent" costs incurred to implement demand-side management and energy efficiency (DSM/EE) programs. In addition, the Commission "*may* approve other incentives." N.C.G.S. § 62-133.9(d)(2) (emphasis added). These incentives may include net lost revenues, which are the revenues that the utility has forgone by implementing the DSM/EE program. The Commission has long held that "net lost revenues are not a cost but, instead, a type of utility incentive that may be recovered in an annual rider pursuant to G.S. 62-133.8(d)(2), assuming that recovery is found to be appropriate by the Commission." Order Adopting Final Rules, *Rulemaking Proceeding to Implement Session Law 2007-397*, No. E-100, Sub 113, 95 (N.C.U.C. Feb. 29, 2008).

As described above, under the Company's proposed decoupling mechanism, the Company proposes subtracting any net lost revenues attributable to DSM/EE programs from the net decoupling amount. (Tr. vol. 11, 147) The Company's proposal to subtract DSM/EE net lost revenues from the residential decoupling mechanism is not appropriate. Instead, the proper approach is for the Commission to cease the lost revenue adjustment mechanism (LRAM) and have all lost revenues recovered via decoupling.

First, the Company's proposed approach relies on the EM&V calculations being accurate. The EM&V process "is a labor-intensive exercise that can be contentious and litigious." (Tr. vol. 15, 408) Because decoupling sets a revenue-per-customer, the Company would not need to rely on an EM&V process to determine the impact of any given program. (*Id.*)

Second, the LRAM and decoupling serve the same purpose, but the decoupling is the superior method. Both LRAMs and decoupling break the utility's incentive to encourage higher energy usage, but the LRAM only applies to DSM/EE programs. (*Id.* at 407) The Company's proposed approach essentially gives "two bites at the apple" to recover net lost revenues related to DSM/EE programs, thus making those revenues preferable to lost revenues due to other types of conservation. By only using a single method to recover all lost revenues, the utility will be indifferent to the specific program that is causing a decrease in sales. (*Id.* at 407-08) The NERP PBR Study group recognized this link between net lost revenues under the DSM/EE mechanism and decoupling but noted that "[d]ecoupling goes a step further [than net lost revenues] by removing the incentive/disincentive to increase or reduce sales in all situations." (PBR Regulatory Guidance at 11)

Finally, eliminating the LRAM would enhance regulatory economy. The Commission would not need to address the Company's lost revenues through the

DSM/EE mechanism and decoupling proceeding but could instead utilize a single proceeding to accomplish the same result. Other states have recognized that this is the superior approach—only a single state maintains both an LRAM and decoupling mechanism. (Tr. vol. 15, 408) This is because "LRAMs are often viewed as the 'first-step policy solution on the way to decoupling.'" (*Id.*)

The Company argues that the LRAM should be left in place because "identifying the [net lost revenues] attributable to its DSM/EE programs" "provide[s] transparency regarding the financial impacts of the utility energy efficiency programs." (Tr. vol. 16, 239) It is important to note that the actual collection of net lost revenues from DSM/EE programs is not necessary for them to be identified and reported to the Commission. If the Commission is interested in receiving that information, it can implement a tracking metric to that effect or simply require its reporting in the DSM/EE rider docket.

Next, the Company argues that the LRAM is necessary because the decoupling mechanism is limited to the residential class. Maintaining the LRAM for non-residential customers would, in the Company's opinion, "create confusion in that NLR would be included in the EE rider for non-residential classes but not for the residential class." (Tr. vol. 16, 239) The Company has not articulated who would be confused by this difference or why that alleged confusion necessitates a more complex decoupling mechanism.

Finally, the Company argues that because the decoupling mechanism only runs through the MYRP period, this would create confusion at the end of the MYRP period. (*Id.*) As described above, net lost revenues are an optional incentive rather than a cost the Company is guaranteed to recover. Nothing prevents the Company from filing a new MYRP application prior to the end of the MYRP period such that there will be no gap. This is not a sufficient reason to maintain an unnecessary mechanism that potentially increases costs to ratepayers.

If the Commission approves the residential decoupling mechanism sought by the Company, then it is no longer appropriate to allow net lost revenues attributable to residential customers to be recovered under the DSM/EE mechanism. The PBR Study Group agreed with this recommendation, finding:

> If North Carolina enacts revenue decoupling for electricity, the lost revenue adjustment mechanism (LRAM) associated with the existing EE/DSM incentive will *no longer be needed and will need to be removed* by the NCUC for the classes included in decoupling.

(PBR Regulatory Guidance at 24) (emphasis added). In fact, the PBR Study Group found this so fundamental that one of the three actions that the group identified the Commission would need to take in its first PBR rate case was "for the customers included in decoupling, amend as needed the lost revenue adjustment mechanism (LRAM) that is part of the existing EE/DSM incentive, since decoupling adjusts revenue in a different manner." (PBR Regulatory Guidance at 29-30)

VI. THE COMMISSION SHOULD REJECT THE PROPOSED RENEWABLES INTEGRATION AND ENCOURAGEMENT PIM AND ADOPT THE AGO'S CARBON EMISSIONS REDUCTION AND FUEL SOURCE RETURN ON EQUITY DIFFERENTIATION PIM.

The Company's initial application contained four performance incentive mechanisms (PIMs): (1) a Peak Load Reduction (PLR) PIM, (2) a Reliability PIM, (3) a Renewables Integration & Encouragement PIM, and (4) an Affordability PIM. (Tr. vol. 12, 91-92)

N.C.G.S. § 62-133.16(a)(6) defines a PIM as "a rate-making mechanism that links electric public utility revenue or earnings to electric public utility performance in targeted areas consistent with policy goals, as that term is defined by this section, approved by the Commission, and includes specific performance metrics and targets against which electric public utility performance is measured." Under the PIM Settlement, the Company, the Public Staff, and CIGFUR III agreed to modify the Company's proposed PLR, Reliability, and Renewables Integration and Encouragement PIMs. (PIM Settlement at 3-6) Under the Affordability Settlement, the Affordability PIM has now been removed. (Affordability Settlement 3) The PLR PIM and Renewables Integration and Encouragement PIM are unreasonable and should be rejected.

AGO witness Balakumar identified six key questions that the Commission should use to evaluate PIM proposals:

1. Does the PIM incentivize the intended outcomes instead of individual steps toward achieving those outcomes?
2. Does the PIM consider the value of symmetrical versus asymmetrical incentives?
3. Does the PIM ensure that any incentive formula is consistent with the desired outcome?
4. Does the PIM ensure a reasonable magnitude for the incentive?
5. Does the PIM tie the incentive formula to actions within the control of the utility?
6. Does the PIM allow the incentives to evolve?

(Tr. vol. 15, 257-59)

A. <u>The Company's proposed Renewables Integration and Encouragement PIM is unreasonable.</u>

The Company's proposed Renewables Integration and Encouragement PIM includes three separate metrics, each of which is addressed below. (PIM Settlement at 4)

i. Metric A: DER Integration should be modified to incentivize all Distributed Energy Resources and capacity amounts in addition to the number of DERs.

The Company proposed Metric A: DER Integration in order to advance Net Energy Metering (NEM) projects. (Tr. vol. 11, 168) This PIM will provide rewards to the Company for exceeding targeted numbers of NEM interconnections. (*Id.* at 175) Initially, these targets were set based on "historical three-year average" of new NEM projects. (*Id.*) The Company would then earn a variable financial reward for exceeding these by certain degrees (5%, 15%, and 25%). (*Id.* at 176) Under the PIM Settlement, Metric A was revised to use a rolling three-year average rather than the static three-year historical average. (PIM Settlement at 4; Tr. vol. 11, 205; Tr. vol. 15, 279)

AGO witness Balakumar recommended two additional modifications to Metric A: (1) the PIM should be broadened in order to incentivize all types of distributed energy resources (DERs), rather than just NEM projects, and (2) the PIM should incentivize total DER capacity installed in addition to the number of installations. (Tr. vol. 15, 280-84) The definition of DERs set forth in N.C.G.S. § 62-133.16(a)(3) includes "energy efficiency, distributed generation, demand response, microgrids, energy storage, energy management systems, and electric vehicles.” AGO witness Balakumar’s revised Metric A would include each of the DERs covered under that provision. (Tr. vol. 15, 283)

The Company stated that it is “not opposed to considering a DER PIM that expands its NEM metric to include other types of DERs” and that it “agrees that DERs, in addition to standalone solar, are critical[.]” (Tr. vol. 16, 294) Nevertheless, the Company argues that witness Balakumar’s first modification be rejected because “metrics not controllable or minimally controllable by the utility should be upside only.” (Tr. vol. 16, 295) Given that N.C.G.S. § 62-133.16(c)(3) requires that “[t]he policy goal targeted by a PIM shall be clearly defined, measurable with a defined performance metric, and solely or primarily within the electric public utility's control,” few PIMs would be eligible for a penalty using this logic. The NERP PBR Study Group stated that the determination whether to impose a reward or penalty “rests on existing utility incentives (and disincentives), the existing regulatory environment, and the level of utility control over the desired outcome.” (PBR Regulatory Guidance at 20)

The Company’s contention that DER adoption is “not controllable” is also illogical. The Company claims that NEM adoption is “solely or primarily” within the Company’s control. (Tr. vol. 11, 186) It is a logical impossibility that a major component of DERs is “solely or primarily” within the Company’s control, but the broader category is “not controllable or minimally controllable.” In fact, under this initial iteration, witness Balakumar suggested that the baseline be set based only on NEM projects—the same metric used by the Company. (Tr. vol. 15, 284-87) The argument that DER adoption is not within the Company’s control lacks merit.

Witness Balakumar's second modification is necessary because the current PIM design "does not necessarily incentivize the Company to integrate maximum amounts of DERs and DERs of all sizes[.]" (Tr. vol. 15, 281) Instead, by incentivizing the number of interconnections, the Company may "focus only on smaller interconnections (less than 20 kW) which are typically smaller in size and higher in number[.]" (*Id.*) By measuring PIM achievement based on capacity of DERs interconnected, rather than number, the Company will be incentivized to pursue DER interconnection of all sizes. This is important as "larger installations will have a greater per-interconnection impact[.]" (*Id.*) Public Staff witnesses Thomas and Williamson believe that "[t]he appropriate metric is the cumulative nameplate capacity in MW" when discussing their utility-scale solar PIM. (Tr. vol. 14, 300) Their recommendation is no less applicable here.

AGO witness Balakumar designed a revised Metric A to reflect these changes. Witness Balakumar's DER Integration PIM used historical data of total NEM capacity installed to design a baseline of performance:

Incremental NEM Connections	Interconnections	Capacity (MWs)	Year over Year (YoY) Performance
2019	2.572	23	
2020	2,894	26	13%
2021	3,558	27	23%
2022	5,081	41	43%
		Average YoY Growth	**26%**

(Tr. vol. 15, 283) Company witness Bateman argues that this would require "incremental DER interconnections would have to increase by 46.5% and installed capacity would have to increase by 50% above his baseline just to receive the minimum reward of $500,000." (Tr. vol. 16, 295) As shown above, this is consistent with historic DER adoption rates despite the headwinds experienced by the rooftop solar industry over the past three years. (Tr. vol. 16, 286; Tr. vol. 15, 285-86)

Using this data, the revised DER Integration Metric includes five tiers of performance:

# of Interconnections Performance (Baseline: 4,320)	**Capacity Performance (Baseline: 34 MW)**	**Rewards/Penalties**
0%	0 MW	($1,000,000)
15.5%	3.75 MW	($500,000)
31%	7.5 MW	$0
46.5%	11.25 MW	$500,000
62%	15 MW	$1,000,000

(Tr. vol. 15, 284)

ii. *Metric B: Large Customer Renewable Program Encouragement should be rejected*.

The Company initially proposed a Metric B that "provides an incentive for the Company to design, obtain regulatory approval of, and subscribe large customers to renewable programs[.]" (Tr. vol. 11, 206) The purpose of Metric B is to provide an opportunity to "customers [who] want to reduce the impact of their carbon emissions by choosing a cleaner generation mix now." (*Id.* at 205) The Company would be rewarded based on the cumulative share of commercial and industrial customers enrolled in one of the Company's renewable customer programs. (*Id.* at 177) Three tiers of rewards would be achievable based on 30%, 50%, or 70% of eligible program capacity being subscribed. (*Id.*) The PIM Settlement decreased the financial incentive for achieving each tier, but otherwise made no changes to Metric B. (PIM Settlement at 5)

The Company states that the purpose of this PIM is to encourage the Company "to design, obtain approval of, and subscribe customers to new renewable programs that meet these customers' desires for access to clean energy resources." Section 5, subsection 4 of House Bill 951 requires the Commission to "establish a rider for a voluntary program that will allow industrial, commercial, and residential customers who elect to purchase from the electric public utility renewable energy or renewable energy credits . . . to offset their energy consumption[.]" The Company is legally required to design programs that would be eligible for this PIM. It is inappropriate to offer an incentive to the Company for accomplishing something it is legally required to do.

Most importantly, this PIM is subject to potential "gaming" by the Company. The PIM is set based on a ratio: the numerator is the total subscribed program capacity, and the denominator is the total program capacity. The Company has full control over the total program capacity. (Tr. vol. 15, 291) This would allow the Company to "leverage information asymmetry to earn rewards without committing resources to increasing customer participation in renewable energy programs." (*Id.*) Instead, the Company can simply size the programs based on the level of demand that they determine exists. (*Id.*)

Public Staff witnesses Thomas and Williamson seemingly shared these concerns: "A capacity limit that is set below anticipated enrollment requests would result in the Company easily surpassing the 30%, 50%, and 70% enrollment thresholds in the tiered reward structure." (Tr. vol. 14, 346) Despite these concerns, the PIM Settlement did not alter the enrollment tiers, but simply lowered the dollar amounts associated with achieving each tier. (PIM Settlement at 6)

iii. Metric C: Utility-Scale Renewables Interconnection should be rejected.

The Company's original Metric C provided an incentive, very similar to Metric B described above, "for the Company to design, obtain regulatory approval of, and subscribe residential customers to voluntary shared solar programs[.]" (Tr. vol. 11, 170) However, under the PIM Settlement, Metric C was drastically altered. The Company's original Metric C was removed entirely and, instead, a Utility-Scale Renewable Interconnection PIM was inserted in its place. (Tr. vol. 11, 199)

The Utility-Scale Renewable Interconnection PIM was proposed by Public Staff witnesses Williamson and Thomas. (Tr. vol. 14, 350) This PIM would offer the Company an incentive for interconnecting utility-scale solar and solar plus storage above the interconnection limits identified during the Carbon Plan proceeding. *(Id*. at 353-54) Under the Public Staff's original proposal, the Company would receive $1 million in Rate Year 2 for exceeding 646 MW of capacity, $2 million for exceeding 745 MW, and $4 million for exceeding 840 MW. (Tr. vol. 14, 357) For Rate Year 3 these tiers would increase to $2 million for exceeding 980 MW, $3.5 for exceeding 1,130 MW, and $6 million for exceeding 1,275 MW. (*Id.*) The version agreed to in the PIM Settlement, provides the Company with $1 million in Rate Year 2 for exceeding 551 MW of capacity, $2 million for exceeding 634 MW, and $4 million for exceeding 716 MW; for Rate Year 3 these tiers would increase to $2.5 million for exceeding 836 MW, $3.5 for exceeding 961 MW, and $6 million for exceeding 1,087 MW. (PIM Settlement at 6) Neither the PIM

Settlement nor its supporting testimony explained the rationale for lowering these thresholds. While other parties will undoubtedly argue whether this PIM is sufficiently ambitious, it is important to note that the performance tiers simply mirror the amount that the Company is already required to connect under the Company's approved Carbon Plan. (Tr. vol. 11, 199)

Altogether, the Company-proposed Renewables Integration and Encouragement PIM is insufficient and goes against many of the best practices for designing PIMs. The Company's decision to focus only on a single type of renewable resource and customer programs is too narrow. "Narrowly designed PIMs have more potential for over-incentivizing the Company through multiple related PIMs, when one broader comprehensive PIM could be used." (Tr. vol. 15, 290) As AGO witness Balakumar stated: "this PIM only narrowly focuses on a single type of renewable resource at the expense of other solutions to reduce emissions—which is the end goal." (Tr. vol. 15, 292)

The Company acknowledged the "advantage of PIMs is their ability to align utility financial incentives with policy goals." (Tr. vol. 11, 158) The Company's proposed PIMs fail to leverage this advantage. Instead, they align the Company's financial incentives with a single resource option instead of the underlying policy goal. AGO witness Balakumar explained:

> A fundamental element of designing performance incentive mechanisms is ensuring they are simply structured to incentivize the utility to take all actions as opposed to individual actions necessary to achieve the intended outcome. Incentivizing individual actions can lead to excessive incentives and ultimately lead to the failure of achieving the intended outcomes.

(Tr. vol. 15, 257) The Renewables Integration and Encouragement PIM agreed to under the PIM Settlement fails to satisfy this fundamental tenet of performance-based regulation.

B. The AGO's proposed Carbon Reduction PIM is a more appropriate means of incentivizing carbon emissions reductions.

AGO witness Balakumar recommended an alternative PIM targeting carbon emission, which, unlike the Company's proposed PIM, encourages the Company to "pursu[e] a holistic, system-level approach that includes a variety of strategies to reduce carbon emissions, including customer renewable programs, grid-scale renewable and storage, energy efficiency, coal retirements, and others." (Tr. vol. 15, 290) The AGO's Carbon Reduction PIM directly aligns the Company's financial incentives with the policy goal for reducing carbon emissions.

The Carbon Reduction PIM rewards or penalizes the Company, respectively, for exceeding or falling below the annual carbon emission reductions identified in the Company's initial Carbon Plan. (Tr. vol. 15, 293-94) The baseline carbon emissions are determined by linearly interpolating the carbon emissions necessary for the Company to achieve the 2030 carbon emissions target set forth in N.C.G.S. § 62-110.9. (*Id.* at 293) This is the same technique that was used in the Company's Carbon Plan modeling. The resulting linear baseline is below:

Year	**CO2 Emissions (short tons)**
2021 (actual data)	23,034,151
2022	21,897,000
2023	20,761,650
2024	**19,625,399**
2025	**18,849,148**
2026	**17,352,898**
2027	16,216,647
2028	15,080,396
2029	13,944,146

2030 (HB 951 target)	12,807,895

(Tr. vol. 15, 294) These baselines represent what would occur if the Company took equal steps in each and every year between 2021 and 2030 to achieve the statutory target.

Based on these baselines, the Company is rewarded or penalized $40,000 for every 0.1% decrease or increase in carbon emissions relative to the baseline up to a maximum of $4 million. (Tr. vol. 15, 295) As described below, the AGO's Carbon Reduction PIM is within the Commission's authority and the superior PIM for addressing carbon emission reductions.

i. The Carbon Emissions Reduction PIM is within the Commission's authority to approve.

N.C.G.S. § 62-133.16(a)(8) limits the Commission's authority "with respect to environmental standards," such that "the Commission may not approve a policy goal that is more stringent than is established by (i) State law, (ii) federal law, (iii) the Environmental Management Commission pursuant to G.S. 143B-282, or (iv) the United States Environmental Protection Agency." The Company argues that because N.C.G.S. § 62-110.9 establishes carbon emissions reduction targets of 70% by 2030 and carbon neutrality by 2050, the Commission is prohibited from establishing any PIMs addressing carbon emissions. It is not.

When determining the meaning of a statutory provision, the inquiry "properly begins with an examination of the plain words of the statute." *Correll v. Div. of Soc. Servs.*, 332 N.C. 141, 144, 418 S.E.2d 232, 235 (1992). "If the statutory language is clear and unambiguous, the court eschews statutory construction in favor of giving the words their plain and definite meaning." *State v. Beck*, 359 N.C. 611, 614, 614 S.E.2d 274, 277 (2005). The words of the statute make clear that the Commission is only prohibited from establishing a policy goal that is "more stringent" than State law. A term that is not defined anywhere in the statute must be "interpreted according to its ordinary meaning." *Wells Fargo v. Amer. Nat. Bank and Trust Co.*, 250 N.C. App. 280, 284, 791 S.E.2d 906, 910 (2016) (citing *Morris Commc'ns Corp. v. City of Bessemer City*, 365 N.C. 152, 158, 712 S.E.2d 868, 872 (2011)).

There is no ambiguity in the provision: the Commission is enabled to pursue policy goals that are less stringent than or equally as stringent as those established by State law. The AGO Carbon Reduction PIM adheres to that limitation because the PIM never requires the Company to exceed 70% carbon emissions reduction by 2030.

Even assuming, *arguendo*, that the limitation in N.C.G.S. § 62-133.16(a)(8) is ambiguous, the rules of statutory interpretation dispense with the Company's reading. "[W]here the statute is ambiguous or unclear as to its meaning, the courts must interpret the statute to give effect to the legislative intent." *In re Ernst & Young, LLP*, 363 N.C. 612, 616, 684 S.E.2d 151, 154 (2009). Canons of statutory interpretation are only employed "[i]f the language of the statute is ambiguous or lacks precision, or is fairly susceptible of two or more meanings[.]" *Abernethy v. Bd. of Comm'rs*, 169 N.C. 631, 636, 86 S.E. 577, 580 (1915).

The above reading of the statute is bolstered by N.C.G.S. § 62-133.16(d)(2)(f), which explicitly allows the Commission to evaluate whether the PBR application encourages carbon reductions. When interpreting a statute, the

Commission should "adopt an interpretation which will avoid absurd or bizarre consequences, the presumption being that the legislature acted in accordance with reason and common sense and did not intend untoward results." *State ex rel. Com'r of Ins. v. N.C. Auto. Rate Admin. Off.*, 294 N.C. 60, 68, 241 S.E.2d 324, 329 (1978). It would be absurd for the General Assembly to allow the Commission to consider whether a PIM encourages carbon reductions, but not to provide an incentive to do so. Indeed, the Company acknowledges that the PBR statute "recognizes that achievement of the targeted CO2 reductions requires the modernization of the ratemaking construct in North Carolina, consistent with modernized ratemaking practices around the country" and "introduce[s] modern ratemaking practices that will better position the Company to meet the State's policy goals and customer expectations while keeping rates affordable." (Tr. vol. 7 61-62)

N.C.G.S. § 62-110.9—enacted under the same Act, S.L. 2021-165, as N.C.G.S. § 62-133.16(a)(8)—authorizes the Commission to "take all reasonable steps" to achieve the carbon emissions reductions targets and to "[d]evelop a plan, . . . to achieve the least cost path" when doing so. The ordinary meaning of "step" is "a stage in a process" and "an action, proceeding, or measure often occurring in a series." *Merriam-Webster.com Dictionary,* Merriam-Webster (2023). Similarly, a "path" is often defined as "the continuous series of positions or configurations that can be assumed in any motion or process of change by a moving or varying system." *Id.* Together, these clauses show a clear legislative intent that the Commission is not only authorized but expected to implement requirements prior to 2030 to ensure the statutory goals are achieved. Indeed, the Commission has already done so through the enactment of its initial Carbon Plan. The Carbon Reduction PIM would create a more stringent goal only insofar as it "help[s] to reduce execution risk and ensures a consistent trajectory towards meeting [the] 2030 target." (Tr. vol. 15, 297)

N.C.G.S. § 62-110.9 provides that the Commission "retain[s] discretion to determine optimal timing" of actions under the Carbon Plan process, "including discretion in achieving the authorized carbon reduction goals by the dates specified in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction[.]" This provision to allow the Commission to delay compliance with the 70% carbon reduction target under specific circumstances, however, is also broad enough to allow the Commission to *accelerate* compliance if doing so constitutes the "least cost path to compliance."

ii. The Carbon Reduction PIM is supported by public policy.

The AGO's Carbon Reduction PIM is superior to the Company's proposed Renewables Integration and Encouragement PIM. The Carbon Reduction PIM addresses five separate public policy goals identified by N.C.G.S. § 62-133.16(d)(2), including encouraging "carbon reductions," "utility-scale renewable energy and storage," "DERs," "energy efficiency," and "beneficial electrification, including electric vehicles."

While the Company states that its proposed Renewable Integration and Encouragement PIM encourages "DERs," "utility-scale renewables and energy storage," and "carbon reductions," the Carbon Reduction PIM is more effective in doing so by allowing the Company to maintain flexibility to ensure that it is pursuing the most cost-effective means of achieving carbon emissions reductions. (Tr. vol. 15, 293) Pursuing carbon emissions reductions rather than a specific resource type allows the Company to pursue the most cost-effective path to decarbonization (*Id.* at 290) The focus on a single resource type can result in what some refer to as "distortive behavior," which occurs when "the utility devotes excessive resources to the targeted area, which decreases the overall performance of the utility." (Tr. vol. 13, 79, 100; CIGFUR III Williamson Direct Cross Exhibit 2 at 48 (NRRI Report))

The Carbon Reduction PIM ensures that "the Company will be incentivized to take all actions to reduce emissions[.]" (Tr. vol. 15, 257) For example, the Company could achieve the Carbon Reduction PIM through the implementation of additional DSM/EE programs, wind generation, etc. The AGO's Carbon Reduction PIM is more in line with the recommendations of the PBR Study Group, which noted that:

> A utility might prefer program-based PIMs, i.e., where incentives are awarded based on measurable actions, programs, and resources deployed or encouraged by the utility, over outcome-based PIMs given the risk that external factors may influence utility performance on the incentivized outcome (and therefore its compensation) . . . . However, a program-based PIM runs the risk of not achieving the desired outcome or decreasing the utility's flexibility to choose and amend the portfolio of programs and investments that best produces the desired outcomes.

(PBR Regulatory Guidance at 20) NCJC *et al.* witness Posner similarly stated that:

> Outcome-based PIMs focus on the achievement of a policy goal or desirable outcome rather than the specific actions taken to deliver that outcome. Outcome-based PIMs are generally preferable because they allow the utility flexibility to choose which portfolio of programs and investments best produce desired outcomes most cost-effectively.

(Tr. vol. 15, 916)

Finally, the AGO's Carbon Reduction PIM is in line with the preferred metric identified by the PBR Study Group: tons of carbon dioxide reduced. (PBR Regulatory Guidance at 24) As AGO witness Balakumar explained, it "will help incentivize the Company to take action to reduce emissions in the near term, helping to reduce execution risk and ensure a consistent trajectory towards meeting its 2030 target." (Tr. vol. 15, 297)

C. <u>The AGO's Fuel Source ROE Differentiation PIM is supported by public policy and should be approved by the Commission.</u>

AGO witness Balakumar recommended the adoption of a Fuel Source Return on Equity Differentiation (FSRD) PIM. (Tr. vol. 15, 298) The FSRD PIM would incentivize the Company to invest in carbon-free generation by providing a lower return on equity (ROE) for carbon-emitting generation sources. (*Id.*) Carbon-emitting sources not in service prior to the approval of the initial Carbon Plan would receive an ROE 25 basis points lower than carbon-free investments. (*Id.*)

N.C.G.S. § 62-133.16(c)(5) allows for PIMs that provide "[r]ewards or penalties based on differentiated authorized rates of return on common equity to encourage utility investments or operational changes to meet a specific policy goal, which shall not be greater than 25 basis points." Commission Rule R1-17B(d)(3)(e)(ii) similarly authorizes "differentiated authorized rates of return on common equity (or its equivalent) to encourage utility investments or operational changes to meet a specific Policy Goal[.]" The PBR Study Group found that this PIM design option "could more fundamentally impact utility investment decisions." (PBR Regulatory Guidance at 29)

Even if the Company's Renewables Integration and Encouragement PIM or the AGO's Carbon Reduction PIM are adopted, the Company has "an inherent shareholder and operational bias towards building more carbon-emitting resources." (Tr. vol. 15, 298-99) For example, N.C.G.S. § 62-110.9(2)(b) provides that new solar generation is subject to a 45%/55% ownership split between third parties and the Company. Thus, there is an incentive for the Company to pursue other, Company-owned resources. "By pairing a disincentive with the Carbon Reduction PIM, the Company will be encouraged to overcome its shareholder and operational biases and only deploy carbon-emitting fuel sources when absolutely necessary." (Tr. vol. 15, 300)

The Company's contention that the "Commission determines which generation resources are necessary for serving the Company's customers" ignores the substantial role that the Company plays in the resource planning process and the options presented to the Commission. (Tr. vol. 16, 303) Therefore, the Commission should approve the FSRD PIM to align the Company's financial incentives with the State's policy goals.

VII. THE COMMISSION SHOULD REJECT THE PROPOSED PIM RELATED TO PEAK LOAD REDUCTION, ADOPT THE AGO'S PEAK LOAD REDUCTION PIM, AND INITIATE A DEFAULT TOU PILOT PROGRAM.

The Company's application included a Peak Load Reduction (PLR) PIM that would share savings from peak load reductions attributable to customer enrollment in the Company's dynamic and time-differentiated rates. (Tr. vol. 11, 171) This preliminary design would have "estimated winter peak kW reduction associated with customer enrollment" in TOU rates, and then distributed savings based on the "value [of] the utility system benefits from reducing peak capacity." (*Id.*)

Under the PIM Settlement, the PLR PIM was renamed as the Time-Differentiated and Dynamic Rate Enrollment PIM (TOU PIM). (Tr. vol. 11, 199) The key difference between the PLR and TOU PIMs is that, rather than attempting to estimate the value of peak load reduction attributable to TOU enrollment, the TOU PIM simply provides the Company a $5 incentive for every customer that enrolls in an eligible rate. (*Id.* at 202-203) This is an increase from the $4 per customer recommended in the testimony of Public Staff witnesses Thomas and Williamson. (Tr. vol. 14, 297) The Company believes that $6.50 in system benefits are created for each customer that enrolls in a TOU rate. (Tr. vol. 16, 275) This means that the TOU PIM gives the Company 77% of anticipated system benefits compared to 70% under its initially proposed PLR PIM. (Tr. vol. 14, 281)

A. <u>The proposed PLR and TOU PIMs are unreasonable.</u>

The purpose of TOU rates is not to address peak loads. TOU rates are meant to “reduc[e] the average high load time periods as opposed to reducing the extreme loading events that set annual system peaks.” (Tr. vol. 15, 263) While TOU rates may shift energy from peak periods during “average high load time periods” they do not generally “reduc[e] the extreme loading events that set annual system peaks” due to the fact that TOU periods and prices don’t change with high system load events. (*Id.*; *see also* Tr. vol. 14, 289) The Company provided no evidence that simply transitioning customers to TOU rates would provide benefits to the grid. This is because “enrollment does not actually provide any meaningful information on whether customers changed their behavior and reduced system peak load.” (Tr. vol. 15, 265) Public Staff witnesses Thomas and Williamson agreed with this assessment: “the [Company’s] proposed metric offers no real benefit to the system . . . mere enrollment in TOU rates does not directly correlate to winter peak load reductions across the Company's footprint." (Tr. vol. 14, 287-88) Company witnesses Byrd and Beveridge acknowledged as much, stating "merely moving a customer to a TOU rate does not create system benefits." (Tr. vol. 10, 31)

The Company used a study of its TOU pilot program to determine that the average expected winter peak load reduction per residential customer is between 0.1 and 0.4 kW. (Tr. vol. 14, 281 n.5; Duke Energy Carolinas, LLC's Final Report on Dynamic Rate Pilots, No. E-7, Sub 1146, at 6 (August 2, 2021)) However, that pilot program was not based on the TOU rates that would serve as the basis of the TOU PIM. (Tr. vol. 14, 288) Public Staff witnesses Thomas and Williamson noted that "there is no guarantee that this level of winter peak load reductions will occur with greater enrollment." (*Id.*) Further, the TOU pilot program was limited to residential customers. (*Id.*) The TOU PIM will initially be limited to residential rates, but the Company may later include non-residential rates. (Tr. vol. 12, 68; PBR Policy Panel Exhibit 1 at 1) The PIM Settlement does not address whether or how the incentive amount will be adjusted for non-residential rates.

Further, the PLR and TOU PIMs could be easily exploited by the Company. The Company has introduced a Rate Comparison Tool, which uses customer-specific usage data to generate a customer's best rate option. (Tr. vol. 11, 59) The Company could earn the proposed PIM by simply informing customers they could save money by switching rates. Doing so would provide no system benefits but, under the TOU PIM, would allow the Company to earn $5 for each customer that chooses to switch. (*Id.* at 202-203)

This also raises concerns about whether the proposed TOU PIM adheres to N.C.G.S. § 62-133.16(c)(3)'s requirement that "[t]he policy goal targeted by a PIM" be "solely or primarily within the electric public utility's control." The Company's migration adjustment assumed that all customers that could save 10% or more on their annual bill, without taking any additional action, would do so irrespective of any actions taken by the Company. (Tr. vol. 10, 134) The TOU PIM does not account for these customers. Therefore, the Company would be given a reward for customers who may have switched rates for reasons completely outside of the Company's control.

A final, related concern is that the TOU PIM allows the Company to earn the $5 incentive even if a customer is required to enroll in a TOU rate. For example, under the Company's revised residential net metering rates approved by the Commission, all new and many existing residential net metering customers will be required to enroll in TOU rates starting in 2027.[6] Despite taking no action to encourage that customer's enrollment, the Company would earn an incentive.

B. <u>The AGO's proposed Peak Load Reduction PIM is a more appropriate means of incentivizing peak load reduction and should be incorporated in the DSM/EE mechanism.</u>

As the Company acknowledged, peak load reductions "play a key role in [] efforts to contain the cost of service as beneficial electrification and reliance on

[6] *Order Approving Revised Net Metering Rates*, No. E-100, Sub 180 (N.C.U.C. Mar. 23, 2023) (Sub 180 Order). The Commission's order allows existing NEM customers to enroll in a bridge rate for a limited period, however, participation in the bridge rate is capped and may be terminated under certain circumstances.

solar and other intermittent renewable resources increase." (Tr. vol. 11, 164) System peaks are a key driver of system resource planning and, therefore, system costs. In addition, reducing peak loads helps avoid the use of peaking generation, thus reducing carbon emissions. Demand response programs, rather than TOU rates, have typically been used to reduce peak load. (Tr. vol. 15, 262) Reduction of system peak loads is important for maintaining affordability. (*Id.* at 268-69)

TOU rates are a type of "shifting" program that "encourage[] the movement of energy consumption from times of high demand to times of day when system loads and/or prices are lowest." (*Id.* at 263) These types of programs do not guarantee actual system peak reductions and are difficult to measure for performance. (*Id.* at 266)

In comparison, "shedding" programs, which address "loads that can be curtailed to provide peak capacity reduction and support the system in emergency or contingency events" and can be more easily and cost-effectively measured with clear quantifiable benefits that "work to reduce resource adequacy of the Company." (Tr. vol. 15, 263-64) Therefore, AGO witness Balakumar recommended that the Commission adopt a peak load reduction PIM that specifically addresses these "shedding" programs. (*Id.*)

Given the prohibition under N.C.G.S. § 62-133.16(c)(4) against counting incentives under both the DSM/EE mechanism and within a PIM, the Commission must either

> (1) eliminate programs from the DSM program and bring the programs under a PLR metric or (2) consolidate winter and summer peak load programs within the DSM/EE rider and design an improved

> incentive within the DSM/EE mechanism that better incentivizes peak load reduction.

(Tr. vol. 15, 268) The AGO recommends that the Commission modify the DSM/EE mechanism consistent with the recommendations of AGO witness Balakumar.

The AGO's PLR PIM "would incentivize the Company to reduce summer and winter peak load using a comprehensive set of demand response programs." (*Id.* at 270) This PIM would be symmetrical, rewarding the Company for exceeding its peak load reduction targets and penalizing them if the targets are missed. (*Id.* at 271) The Company would be rewarded for "increasing firm capacity from demand response programs to address both summer and winter peaks. The Company would be rewarded or penalized separately for their respective summer and winter peak load reduction performance." (*Id.*) AGO witness Balakumar used 412 MW of curtailable load as the baseline for winter peaks based on information provided by the Company during the Carbon Plan proceeding and 646 MW of summer curtailable load based on data provided by the Company. (*Id.* at 272) Public Staff witnesses Thomas and Williamson seemingly endorsed this as the better approach: "a preferred metric for this PIM would be actual TOU reductions during winter peak periods." (Tr. vol. 14, 289)

The AGO's PLR PIM is also consistent with the recommendations of the PBR Study Group, which recommended a preferred metric of "MW reduced from the utility's NCUC-accepted IRP peak demand forecast (for summer and winter peak)" for peak load reduction. (PBR Regulatory Guidance at 21)

C. A default TOU pilot program would allow the Commission to evaluate the costs and benefits of implementing default TOU rates.

TOU rates are an example of a modernized rate design that could allow the Company to lower its revenue requirement. The Company acknowledges that TOU rate adoption "is beneficial to participating customers and the grid more broadly." (Tr. vol. 10, 212) Company witnesses Bateman and Stillman testified that residential customers' "participation levels in these rates ha[ve] been minimal." (Tr. vol. 11, 165) Company witnesses Bateman and Stillman testified that the Company estimates that for each customer that enrolls on a TOU rate, $6.50 in system benefits are created. (Tr. vol. 16, 275) This estimate is not supported by Duke's TOU pilot program results.

The Company acknowledges that subsequent EM&V studies are necessary to specifically quantify system benefits. (*Id.* at 273-74) Public Staff witnesses Thomas and Williamson noted that the TOU study used to support the TOU PIM included only "customers who actively sought out participation in a TOU pilot, and who therefore may be more willing and able to adjust their consumption in response to the TOU rates than other customers." (Tr. vol. 14, 288) Therefore, the TOU study likely does not reflect the grid benefits that would occur with broader TOU adoption.

Nevertheless, the Company does not support moving towards default TOU rates. The rationale for why seems clear: time differentiated rates have the potential to reduce the Company's earnings if customers take action to modify their behavior. However, the residential decoupling mechanism would ensure that the Company recovers any revenue decrease. Further, if default TOU rates were adopted, the Company would likely no longer be able to receive the $5 per customer provided for in the TOU PIM. As witnesses Byrd and Beveridge stated, the Company's preferred roach to expanding TOU rate adoption is to make "TOU rate designs . . . more appealing to customers" and "to encourage voluntary [customer] adoption at present." (Tr. vol. 10, 212-13) It is not clear how the Company can make TOU rates more appealing as all rates are required to be revenue neutral.

The Company believes that the "choice to switch to TOU rates [should be] with the customer." (*Id.*) However, the Company acknowledged that customers on a default TOU rate would still have the option to switch to another rate if they desire. (*Id.* at 212) The Company has offered no reason why, if default TOU rates were adopted, customers could not be allowed to switch rates in less than a year. Further, the AGO has not recommended switching to default TOU rates at this time, but instead to initiate a pilot program to study the impact of default TOU rates on various customer classes and the system more generally. (Tr. vol. 15, 363)

The Company also argues that "the time when a customer decides to move to a TOU rate is a great opportunity to encourage new behaviors or technologies to increase price-responsiveness." (Tr. vol. 10, 213) But the Company can give customers tips to save money at any time—not just when they are switching rates—and the Company already has programs that encourage customers on default rates to modify their behaviors, such as through DSM/EE programs and demand charges. (*See also* Tr. vol. 10, 198-200)

The Company believes that the Schedule RS "provide[s] meaningful incentives for customers to conserve energy or invest in energy efficiency through the Demand-Side Management and Energy Efficiency Programs offered by the Company." (Tr. vol. 10, 212) However, the Company's own rate design proposals reflect the fact that "the cost of consuming energy varies significantly by time of day and season in most instances," which is not reflected by the RS tariff. (Tr. vol. 15, 390) Instead, "residential customers [are not being sent] price signals that incentivize them to reduce and shift energy consumption during peak hours on system" resulting in the "Company having to add more infrastructure to serve peak demand" than would otherwise be needed. (*Id.* at 390-91)

Other utilities and Commissions have already recognized the value of default TOU rates and have enacted them. (Tr. vol. 15, 392-93) This Commission too should evaluate the extent that customers can save money by this shift through both their own actions and reduced system costs. A default TOU pilot program can help identify whether a shift to TOU rates would disproportionately harm low-income customers or—as AGO witness Palmer expects—serve as an additional opportunity for those customers to reduce their bills. (*Id.*) The AGO recommends a one-year pilot program, using the recent study by the Brattle Group for the Maryland Public Service Commission as a model. (*Id.*) This study should include not only early adopters and "structural savers," but also customers who would not normally be expected to be interested in TOU rates. If—as both the AGO and the Company expect—the savings to customers will be significant, the Commission must determine whether it is reasonable for the Company to slow-walk that transition to the detriment of ratepayers.

VIII. THE COMMISSION SHOULD ORDER ADDITIONAL TRACKING METRICS.

Tracking metrics are metrics that the Company will track and publish, but that do not have a direct financial impact tied to them. Tracking metrics are important because they allow the Company, Commission, ratepayers, and stakeholders to “monitor[] and quantitatively measur[e] utility outcomes or performance” and “demonstrate progress toward a particular outcome[.]” (Tr. vol. 11, 158) Public Staff witnesses Thomas and Williamson testified that “having a library of tracking metrics is beneficial to understanding performance across a variety of utility operations.” (Tr. vol. 14, 358)

Tracking metrics are also important because they can “be used to measure and develop an approach that can serve as a basis to inform future PIMs.” (Tr. vol. 11, 158) Public Staff witnesses Thomas and Williamson noted that “sufficient historical data is critical when determining whether the activity measured by a particular metric is performing as expected or is under-performing and needs to be corrected.” (Tr. vol. 14, 277) “Poor baseline data can lead to hindrances in the development of performance-based regulatory framework and lead to PIMs that do not incentivize exemplary utility performance.” (Tr. vol. 15, 259)

The Company’s application called for only three tracking metrics: customer service, carbon emissions reductions, and beneficial electrification from incremental load from EVs. (Tr. vol. 11 pp 184-85) The PIM Settlement agreed on three tracking metrics:

> (1) customer service, as proposed in the Company's initial testimony; (2) beneficial electrification from incremental load of EVs, as proposed in the Company's initial testimony; and (3) a requirement that the Company report the ten worst performing circuits, including an analysis of the cause of each circuit's performance.

(PIM Settlement at 6) Therefore, under the PIM Settlement, the Company no longer plans to have a carbon emissions reduction tracking metric despite the fact that this metric is already tracked or planned to be tracked in the near future.

This limited number and scope of tracking metrics is woefully insufficient. As a point of comparison, the NERP PBR Study group examined Xcel Energy's implementation of tracking metrics. (Tr. vol. 12, 67; CIGFUR III Bateman Stillman Direct Settlement Cross Exhibit 1, Case Study: Minnesota Electricity Performance Based Rates at 5) Xcel Energy proposed tracking 31 different metrics. (*Id.* at 14) The NERP PBR Study Group, of which Company witness Bateman was a co-lead, recommended that "utilities should track as many metrics as are deemed useful and cost-effective." (PBR Regulatory Guidance at 5) For example, although the Company plans to track "beneficial electrification from incremental load of EVs," this is a limited view of the impact, trajectory, costs, and Company efforts related to EVs. In order to have robust data to support the adoption of a future PIM related to EVs, the Commission would need additional tracking metrics related to EVs.

AGO witness Balakumar recommended a number of additional tracking metrics, including:

- Aggregate carbon dioxide emissions:
    - 5 years of historical carbon emissions;
    - Carbon emissions for the current year.
- Generation unit-level carbon dioxide emissions:
    - Historical carbon emissions by fuel source and individual generation unit;

    - Contribution of generation retirements to carbon dioxide emissions reductions by fuel source and generation unit;
    - Contribution of generation additions to carbon dioxide emissions reductions by fuel source and generation unit.
- Strategies to reduce carbon dioxide emissions:
    - Large customer renewable program capacity and subscription level;
    - Residential customer shared solar program capacity and subscription level;
    - Total carbon-free energy capacity additions and procurement costs;
    - Total energy storage capacity additions and procurement costs;
    - Total carbon-emitting energy capacity additions and procurement costs.
- Summer and winter peak performance for the Company's DSM/EE programs by tariff, program, and customer class, as applicable:
    - Load reduction capability interval data and load reduction capability customer contracts;
    - Load reduction capability measured as a weather normalized peak impact;
    - Total MW of firm capacity meeting resource adequacy needs;
    - Total cost per MW of firm capacity meeting resource adequacy needs;
    - Number of times a contingency, program, or other event is called;
    - Total and percentage MW and megawatt-hour ("MWh") participating;
    - Number of customers participating;
    - Percentage of event hours called in top 250 DEC system hours;
    - Kilowatt-hour ("kWh") delivered by time period.
- Summer and winter peak aggregate performance:
    - Average and hourly peak impacts;
    - Peak impacts as a function of temperature;
    - Pre- and post-event impacts;
    - Generation resource mix in DEC's system during top 250 system hours;
    - Generation resource mix in DEC's system during hours when DR was called.
- DER system capacity:
    - Total hosting capacity system-wide, by substation and by feeder;
    - Total interconnected DER capacity by DER type (solar, solar plus storage, standalone storage, vehicle-to-grid EVs, etc.) system-wide, by substation and by feeder;
    - Total number of DERs interconnected by type and size system-wide, by substation and by feeder;
    - Total interconnected DER capacity by size for each DER type;
    - Total DER capacity by DER type in queue system-wide, by substation and by feeder;
    - Total number of interconnection applications by DER type in queue system-wide, by substation and by feeder.

- DER Interconnection Speeds:
    - Average number of days for interconnection for each type of DER by level of interconnection or size.

(Tr. vol. 15, 274-76, 287-88, 297-98) Public Staff witness Williamson testified that he "would support any of the metrics listed in [the NERP] report as potential tracking metrics for the Commission's consideration[.]" (Tr. vol. 14, 305) Many of witness Balakumar's proposed tracking metrics are included in the NERP report. (PBR Regulatory Guidance at 21-27)

The Company plans to develop a public PIM dashboard, which will "allow the Commission, intervenors, and the public at large to view DEC's progress toward the PIM metrics and proposed tracking metrics." (Tr. vol. 11 p 183) This dashboard will have an estimated capital cost of $540,000 and annual operations and maintenance (O&M) costs of about $100,000. (Tr. vol. 11 p 183) The Company already tracks and reports numerous metrics in various dockets before the Commission. It is important the PIM dashboard incorporate those metrics into a single, easily accessible location that shows historical trends. The Commission should attempt to maximize the significant investment being made in the PIM dashboard by approving the additional tracking metrics suggested by AGO witness Balakumar.

IX. MANY OF THE COMPANY'S PROPOSED RATE DESIGN CHANGES ARE UNREASONABLE.

The Company's application included a number of new rate designs and changes to existing rates. Company witness Beveridge testified that some of the Company's key objectives when designing rates are to "align revenues to serve customers across [the Company's] rate classes and rate schedules" and to "design rates that best reflect the costs each customer causes the Company to incur . . ." (Tr. vol. 10, 130-31) As described below, many aspects of the Company's proposed rate designs fail to meet these fundamental objectives.

A. The Commission should approve the TOU periods recommended by AGO witness Palmer.

The Company has proposed a number of changes to TOU periods in this case. Notably, the Company is proposing to shift the On-Peak Summer period to 6:00 PM to 9:00 PM. (*Id.* at 90) AGO witness Palmer instead advocates for an On-Peak Summer period of 5:00 PM to 8:00 PM. (Tr. vol. 15, 362, 366-68) Ensuring that "TOU periods effectively and accurately reflect system costs" is a "foundational step in realigning price signals with the needs of an evolving power system." (Tr. vol. 15, 365) As the Company acknowledged, "properly defined periods [are] necessary to ensure proper price signaling," which can help "enable cost-effective customer adoption of new technologies, such as smart energy management devices, energy storage, and EVs." (Tr. vol. 10, 91) The Company has not offered sufficient evidence to show why its proposed TOU periods are just and reasonable given the flaws highlighted by AGO witness Palmer.

In order to establish its proposed Summer On-Peak period, the Company used the Cost Duration Model (CDM) to project system costs in each hour and month for the years 2021, 2026, and 2030. (Tr. vol. 10, 139, 189; Tr. vol. 15, 367) This analysis incorporated additional solar generation that is expected to be added between now and 2030, which caused "the summer afternoon peak being pushed further back into hours with less sunlight." (Tr. vol. 10, 95) However, the analysis did not account for other non-solar generation resource additions that are likely to occur between now and 2030, such as wind generation. Therefore, the Company's analysis likely overstates the impact of additional solar generation on summer afternoon system costs.

Despite the Company's claim that its proposed changes to its time of use periods "improve price and cost causation alignment" (Tr. vol. 10, 89), AGO witness Palmer's proposed TOU peak periods align better with system costs in each year that the CDM analyzed. (Tr. vol. 15, 367-68) Tables 2, 3, and 4 in AGO witness Palmer's testimony—which contain confidential information—clearly show that witness Palmer's proposed summer on-peak periods more accurately reflect system costs.

Witness Palmer further explained why the Company's justification for using nearly a decade-long forecast to develop its new proposed TOU periods was not persuasive. (*Id.* at 369-70) While witness Palmer agreed that "[r]ate stability is one important consideration," but stated that this "rate design principle does not justify the Company's proposal because system costs at the hour ending at 21 (included under the Company's proposal) are never as high as at the hour ending at 18 (included under my proposal) for any year of the analysis, including 2030." *Id.* at 370. She further noted the several unintended consequences of setting a peak based on projections so far in the future. *Id.* at 370-71.

B. <u>The Commission should order the Company to design and file for approval a Critical Peak Pricing tariff for non-residential customers.</u>

Despite Company witness Byrd's contention that the proposed rate design changes "offer greater opportunity for load management activities to help customers control energy costs and simultaneously create benefits for the broader system," (Tr. vol. 10, 89) the Company's proposed rate offerings exclude one of the most beneficial rate designs: a Critical Peak Pricing (CPP) tariff. Witness Byrd testified that the Company's rate design proposals were meant to "send price signals that encourage system beneficial consumption behaviors . . ." (Tr. vol. 10, 88) Yet none of the Company's proposed non-residential rates specifically target high-load events. (Tr. vol. 15, 383-84) Witness Palmer explained that for 2022, the peak hours of the year were "three consecutive hours on December 24, during Winter Storm Elliott. These three hours represented 1,092 MW in incremental capacity and a 5.9% increase from the peak outside of these hours." (*Id.* at 384) These events drive resource adequacy and system costs. *(Id.)* Conversely, critical peak price signals "allow a utility to flexibly identify peak load events and incentivize customers to shift load during that small number of hours that have an outsized, often significant, impact on system costs." *(Id.)* These tariffs also offer a benefit to participating customers, who enjoy lower off-peak prices in exchange for higher critical peak prices—offering the opportunity to decrease their bills if they respond to critical peak signals. (*Id.* at 386) Because the Company failed to include a rate schedule that offers these benefits to both participating and non-participating customers, the Commission should order the Company to introduce CPP tariffs for commercial and industrial (C&I) customers with demands above 75 kW.

The lack of a CPP option for these customers is perplexing given the Company provides CPP options for residential and SGS customers. *(Id.)* While the Company's proposed Hourly Pricing and TOU tariffs (like OPT-V) provides an option for the most sophisticated customers, CPP tariffs are simpler and provide more stable prices throughout the year. (*Id.*) Public Staff witness Nader noted that "marginal energy prices are volatile and primarily of value to sophisticated customers[.]" (Tr. vol. 11, 737) Many customers may not want to track real-time market conditions or be exposed to the potential volatility of the Hourly Pricing tariff. (Tr. vol. 15, 386) Therefore, the Hourly Pricing tariff is not an adequate substitute for a CPP tariff.

The Company's primary response to AGO witness Palmer's recommendation was to state that non-residential rate designs were discussed during the Comprehensive Rate Design Study (CRDS). (Tr. vol. 10, 190, 203) This argument is unpersuasive. First, as discussed above, mere discussion in a stakeholder workshop is not, nor should it be, binding on the Commission. It is inappropriate to use stakeholder processes to avoid scrutiny of the Company's proposals. Second, there was not consensus regarding this proposal in the CRDS. Indeed, some customers who participated in the CRDS were interested in a CPP option, with one participant going as far as proposing a rate. (Tr. vol. 12, 989; CIGFUR III McLawhorn Metz and Nader Direct Cross Exhibit 4 at 27-29; *see also* Tr. vol. 11, 131; Harris Direct Exhibit 1 at 365)

Enacting a CPP tariff for non-residential customers is beneficial for all customers, including non-participating customers. By shifting load during peak events, non-participating customers benefit from lower system costs and improved system reliability. Therefore, the Commission should order the Company to design and file for approval a CPP tariff for non-residential customers.

C. Demand charges should be reduced under the proposed OPT-V and HLF tariffs with corresponding increase to energy charges.

The Company's proposal to increase demand charges and reduce energy charges for the Optional Power Service, Time of Use with Voltage Differential (OPT-V) and High Load Factor (HLF) rate schedules (Tr. vol. 10, 149) does not reflect cost causation best practices in a changing power system. As the Company's aging coal generation fleet is replaced with cleaner, more cost-effective intermittent resources, the power supply will become "more variable and less dispatchable[.]" (Tr. vol. 15, 364) This increased variability "will make the flexibility of both supply and demand side resources increasingly important." (*Id.*) Rate design plays a critical role in this equation and "must sufficiently incentivize customers to effectively manage their load in ways that maximize value to the grid." (*Id.* at 365)

Many of the Company's proposed rate designs fail to recognize this changing paradigm. AGO witness Palmer testified that "cost causation principles will need to evolve to reflect this broader and more nuanced electric system paradigm. Because renewable energy output is variable, it yields a more dynamic energy supply equation in a system traditionally built to serve variable demand with centralized, dispatchable supply." (*Id.* at 364-65) The Company treats fuel and other short-term marginal costs as variable to be collected through energy charges, while other investments are treated as fully fixed costs recovered via demand charges. This practice "over-emphasizes short-term costs, and therefore revenue collection, and de-emphasizes long-term asset avoidance and overall system efficiency." (*Id.* at 374) For example, "wind and solar facilities would traditionally be considered fixed investments" and thus, under the Company's formulation, be recovered fully via demand charges. *(Id.)* However, these resources are built in order to avoid fuel costs. (*Id.*) The Company's proposed OPT-V and HLF rates are an example of how this evolution can—and will continue to—impact rates.

The Company's proposed OPT-V and HLF rates do not send sufficient price signals to encourage customers to shift their load. Company witness Beveridge said "efficient price signals" were a key consideration in designing rates. (Tr. vol. 10, 133) Company witness Byrd claims that higher demand charges "provide meaningful price signals to encourage system beneficial behavior." (*Id.* at 199) However, demand charges provide muted price signals compared to volumetric rates. (Tr. vol. 15, 376) While the Company's conception of "beneficial behavior" made sense in the traditional power system, it no longer reflects the evolving power system our State is building towards. In fact, "[i]n today's power system, it has become more expensive to serve inflexible load (such as high load factor customers without backup storage) that does not react to temporal system conditions and costs." (*Id.* at 375-76) The Partial Rate Design Agreement and Stipulation of Settlement and Energy Charges Settlement further exacerbate this problem by requiring the majority of any revenue requirement decrease be applied to the energy charges, while limiting the portion of any revenue requirement increase that can be applied to energy charges.

Company witness Byrd recognized that cost causation is but one element that needs to be considered when designing rates, including encouraging peak load reduction and allowing customers to manage and reduce usage, as well as utilizing distributed energy storage to reduce their bills. (Tr. vol. 10, 96-97) But in addition to inadequately reflecting cost causation under a changing power system, demand charges also "do not send granular enough price signals to incent customers to modify their behavior or invest in technology that can be used to flexibly address system needs when the system is under stress." (Tr. vol. 15, 376) Therefore, the Commission should reject the Company's proposal to increase demand charges.

D. <u>The Company's proposed discount rate for OPT-V and HLF customers is below the Company's marginal costs, meaning other customer classes are subsidizing usage during those periods, and should be increased.</u>

The Company's proposed OPT-V and HLF discount rates "do not represent even the marginal cost of providing that energy to customers." (Tr. vol. 15, 379) Company witness Byrd acknowledged this possibility and stated that "the Company will review final pricing in compliance rates to address Witness Palmer's general concern." (Tr. vol. 10, 203) Witness Byrd recognized that it is important for prices to be above unit marginal costs. (*Id.* at 86, 92) The National Regulatory Research Institute highlighted the importance of this concept:

> When a rate falls short of a utility's short-run marginal cost or lies above the price that an unregulated monopolist would charge, for example, a commission would likely find the rate impermissible—that is, consider it "undue." There is also the question of who should bear the burden of a revenue shortfall from offering a lower than embedded-cost rate to certain customers.

(NRRI Report at 31)

As AGO witness Palmer demonstrated, this discrepancy can be quite substantial. For example, compare AGO witness Palmer's confidential Table 8, with her Tables 6 and 7, which reflect DEC's proposed OPT-V Energy Rates for Industrial and General Service customers, respectively. (Tr. vol. 15, 381) For every kWh used by these customers during that discount period, any undercollection as compared to marginal energy costs is being borne by other ratepayers. When a customer class's costs exceed its revenues, then there is an interclass subsidy flowing to that customer class. (*See, e.g.,* Tr. vol. 10, 241)

Therefore, the Commission should order the Company to ensure that all pricing periods exceed the marginal cost of providing energy to the customer.

X. THE COMPANY'S PROPOSED CHANGES TO NON-RESIDENTIAL NET METERING ARE UNREASONABLE.

In addition to the changes to the TOU periods described above, the Company is proposing a number of changes to non-residential net metering. The Company's new Non-Residential Solar Choice Rider (Rider NSC) would increase the eligible system size from 1 MW to the lesser of 5 MW or 100% of the customer's contract demand. (Tr. vol. 15, 387-88) Rider NSC would also require participants to enroll in TOU rates. (*Id.* at 387)

A. <u>The Rider NSC contract term is too short to provide the level of certainty necessary to justify the significant investment required to install rooftop solar.</u>

Customers who choose to participate in the Company's proposed Rider NSC are only guaranteed a contract term of one year. This should be modified to allow customers to have the option to enroll in Rider NSC for a contract term of up to five years. (*Id.* at 388) Installing distributed generation "can represent a significant investment for customers." (*Id.*) A customer making such a significant investment would want some level of certainty that their decision is economically feasible. While customers participating in Rider NSC would not need to renew their participation every year, nothing in the tariff design prohibits the Company from proposing revisions to Rider NSC after a single year. A five-year term sufficiently balances the need for certainty with a rapidly evolving power system. (*Id.* at 388-89)

The Company justified its use of a one-year limitation by responded that such a term is common in the Company's tariff language. (*Id.* at 389) But this justification does not rationalize the unnecessarily short-term length here. For example, the Company sought, and the Commission approved, a ten-year term for its residential NEM tariffs.

B. Customers who enroll in Rider NSC should be permitted to retain all renewable energy credits.

Under the Company proposal, "any renewable energy credit or 'green tags' shall be provided by Customer at no cost to Company" if the customer enrolls in a rate design that does not include a demand charge. (Tr. vol. 11, 66; Byrd Direct Exhibit 7 at 10) This proposal is inequitable given NSC customers do not have the option of enrolling in demand-based rates. All customers—including non-residential customers enrolled in a rate that does not include a demand charge—should be permitted to retain their RECs. This is consistent with the Commission's recent order allowing all residential NEM customers to retain their RECs.[7]

The Company has offered no reasonable rationale why non-residential customers should not also be permitted to do so.

[7] Sub 180 Order at 42.

XI. THE COMMISSION SHOULD ORDER THE COMPANY TO PURSUE COST SAVING STRATEGIES RELATED TO ITS TRANSMISSION MYRP PROJECTS.

There are a number of technologies that the Company failed to evaluate that would defer, delay, or reduce the cost of many of the Company's transmission MYRP projects. (Tr. vol. 15, 314-17) The Company agrees that it did not study these technologies but argues this finding is "irrelevant." (Tr. vol. 8, 392) That is not accurate. It is the utility that has the burden to show that its costs were reasonably incurred.[8] The costs "are presumed reasonable unless challenged."[9] To make a utility satisfy its burden, challengers must offer "affirmative evidence . . . that challenges the reasonableness of [the utility's] expenses."[10] Once the challengers make this showing, the utility must prove that its costs were reasonably incurred.[11]

A. <u>The Company should conduct a cost benefit study of grid-enhancing technologies within six months.</u>

The Commission should order the Company to conduct a study of grid-enhancing technologies (GETs) within six months. GETs encompass a number of different techniques and technologies that "enhance transmission operations and planning," including Advanced Power Control, Dynamic Line Ratings, and Topology Optimization. (Tr. vol. 15, 315) These technologies "enhance transmission planning and operations by increasing the real-time transfer capacity of the existing transmission network, helping to maximize cost-efficiency and

[8] *See* N.C.G.S. §§ 62-75, 62-134(c).
[9] *State ex rel. Utils. Comm'n v. Conservation Council*, 312 N.C. 59, 64, 320 S.E.2d 679, 683 (1984).
[10] *State ex rel. Utils. Comm'n v. Intervenor Residents* (*Bent Creek)*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982).
[11] *Id.*

renewable integration." (*Id.*) GETs can also be deployed more quickly than traditional transmission projects. (*Id.* at 1122-23) These technologies are being successfully deployed in the United States and Europe. (*Id.* at 320) Nevertheless, the Company did not study GETs in relation to the MYRP projects. (*Id.* at 317-18, AGO Burgess Testimony Exhibit 4)

Company witness Maley argues that such a study is inappropriate because "the Commission already considers GETs in the Companies' Carbon Plan proceedings." (Tr. vol. 8, 256) This argument is unavailing as the Commission did not evaluate specific projects or costs during the Carbon Plan proceeding. To the contrary, the Commission is now—for the first time—tasked with evaluating specific project proposals with cost estimates. Part of the prudency evaluation is determining whether there are more cost-effective alternatives that could have been pursued. *See, e.g.,* Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, *Application of Duke Energy Corporation And Progress Energy, Inc., to Engage in a Business Combination Transaction*, Nos. E-2, Sub 998; E-7, Sub 986 (N.C.U.C. June 29, 2012) (noting the obligation "to pursue the most reliable, prudent and cost-effective resources and projects"). Even if the Commission approves the Company's MYRP, the Company may still change, modify, or substitute MYRP projects if it is discovered that a project can be addressed in a more cost-effective manner.

GETs have the potential to lead to drastic savings for ratepayers. A recent study conducted by the Brattle Group with the support of Duke Energy Renewables found that over $175 million in production cost savings could be achieved in the

Southwest Power Pool through the implementation of GETs. (Tr. vol. 15, 317; AGO Burgess Testimony Exhibit 2 (Brattle Study)) With an initial investment of $90 million, this meant that GETs paid for themselves in about six months. (Brattle Study at 9-10)

The Company acknowledged that GETs may have the ability to delay or defer MYRP projects. (AGO Burgess Testimony Exhibit 4) Deferral of MYRP transmission investments can result in ratepayer benefits due to the time value of money and the potential for technology advancement. (Tr. vol. 15, 187) The Company offered no evidence that each of the investments included in the multiyear rate plan was required in spite of the Company's integrating these proposed GETs. Since the Company did not study GETs in relation to MYRP projects, no such evidence can or does exist.

GETs have the potential to lead to a number of benefits to ratepayers that are not captured in the Company's cost benefit analysis for transmission projects. The Company's cost benefit calculation "only measur[es] the reliability benefits to customers." (Tr. vol. 8, 291) This is too narrow a view of the value provided to customers. FERC has identified several categories of benefits that transmission projects can provide, to include:

- Avoided or deferred reliability projects and aging infrastructure replacement;
- Reduced loss of load probability or reduced planning reserve margin;
- Production cost savings;
- Reduced transmission energy losses;
- Reduced congestion due to transmission outages;
- Mitigation of extreme events and system contingencies;
- Mitigation of weather and load uncertainty;
- Capacity cost benefits from reduced peak energy losses;
- Deferred generation capacity investments;

- Access to lower-cost generation;
- Increased competition; and,
- Increased market liquidity.

(*See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028, 2022 FERC LEXIS 541, *27-*30 (2022); *see also* Tr. vol. 15, 316, 1124)

GETs can provide many of these benefits that were not accounted for under the Company's cost-benefit analysis. For example, GETs have the ability to rapidly increase renewable energy interconnection, leading to carbon emissions reductions. The Brattle Study found that GETs enable the interconnection of more than twice the amount of renewables above the base case. (Brattle Study at 8-9) The study also found that GETs led to fewer curtailments of existing renewables. (Brattle Study at 9) A similar study would ensure that North Carolina ratepayers are benefiting from these new technologies wherever possible. At a minimum, the study should analyze:

- Estimated increase in line ratings for DEP's existing transmission system;
- Estimated increases in line ratings of proposed new transmission projects;
- Identification of specific transmission project deferral opportunities;
- Estimated increase in incremental solar that could be integrated;
- Estimated operating cost savings;
- Reliability benefits; and
- A near-term action plan for implementing GETs that are found to be beneficial.

(Tr. vol. 15, 322) This study should be completed within 6 months of the Commission's final order to ensure that MYRP projects can be supplemented or enhanced with GETs if opportunities are found.

B. <u>The Company should be required to evaluate regional transmission projects that could defer or delay the need for MYRP projects.</u>

The Company should be required to evaluate regional transmission projects that could defer or delay the need for MYRP projects. Regional transmission projects have numerous benefits, including increased ability to import cost-effective renewable energy and reliability. (Tr. vol. 15, 330-31) For example, the Lawrence Berkeley National Lab found that regional transmission projects can yield "more than $130 million in benefits per year per 1000 MW of transfer capacity." (Tr. vol. 15, 331) Despite this, none of the Company's proposed MYRP transmission projects are regional projects. (*Id.* at 332, AGO Burgess Testimony Exhibit 5) The Company stated that "it does not generally explore potential regional and interregional projects before" receiving a request from another entity. (*Id.*) This lack of proactivity means that the Company is likely missing key opportunities to delay, defer, or supplement MYRP transmission projects. In his rebuttal testimony, Company witness Maley did not address this recommendation or offer any explanation as to why it would be unreasonable. Therefore, the Commission should order the Company to conduct a study of the costs and benefits of additional regional transmission projects connected to the Company's system within six months.

XII. THE COMMISSION SHOULD IMPLEMENT ADDITIONAL REQUIREMENTS FOR FUTURE MYRP APPLICATIONS.

MYRPs are an important tool for mitigating impacts to ratepayers. MYRPs create a cost containment mechanism that ensures that the utility is executing MYRP projects in the most prudent way possible. Further, the earning sharing mechanism works together with the MYRP to incentivize the Company to implement cost saving measures. (Tr. vol. 11, 150) As the NERP PBR Study Group found:

> MYRPs may give the utility the incentive to control and reduce its costs by giving it the opportunity to keep some of the cost savings as long as the MYRP is coupled with an earnings sharing mechanism. This cost containment incentive could potentially help address the utility's capex bias by motivating the utility to choose the most cost effective solutions for grid needs, regardless whether they are capex or opex.

(PBR Regulatory Guidance at 15)

The Company did not include in its MYRP at least $3.6 billion in capital projects that will occur over the next three years and claims "that maintaining or improving the overall reliability of the Company's entire electric system requires nearly a $12.2B capital project spend [including the non-MYRP costs not included in this rate case] by the end of Rate Year 3 (December 2026)." (Tr. vol. 12, 905; *see also* Tr. vol. 14, 230) That is so, even though "[b]y comparison, DEC's total rate base . . . in this case is $25.5B." (Tr. vol. 12, 905) The Company has already specifically identified what some of these specific projects are and what their costs will be. (Tr. vol. 15, 1112, Goggin Exhibit 2) The cost of these projects will be recovered in a future rate case but will not have been subject to the cost containment pressures from inclusion in the MYRP. Public Staff witness Metz expressed concern that "it is not clear how much of the Company's projected non-MYRP capital spend relates to the future energy and capacity resources identified through resource planning and whether a larger CapEx spend in 2027 through 2030 is looming to further increase rates." (Tr. vol. 12, 905-06)

One of the key policy objectives behind implementing a PBR framework was to provide smoother rate increases and avoiding "rate shock." Keeping a large portion of the Company's capital spend outside of the MYRP means that the "rate shock" is simply delayed until the filing of the next rate case when those costs will be included in rate base. Additionally, projects that are not included in the MYRP will require the Company to incur financing costs, which will ultimately be borne by the ratepayers. Including those projects within the MYRP would avoid those financing costs and also be properly representative of what Duke intends to spend.

The exclusion of a large portion of projected capital projects also means that the earning sharing mechanism is much less likely to be used to the benefit of ratepayers. (Tr. vol. 14, 230) This is because the Company "will be collecting revenue based upon the MYRP request, but investing significantly more capital than is included in the MYRP," reducing the likelihood of overearning. *(Id.)*

The PBR Study Group noted that:

> Commissions have typically allowed MYRPs to cover most utility costs to more comprehensively impact utility spending decisions. If the scope of the MYRP is too narrow, the utility may not be able to commit to a multiple-year rate case 'stay out" or moratorium, depending on the planned investments over that period.

(PBR Regulatory Guidance at 18) The exclusion of large number of projects from the MYRP is especially concerning given many of the projects excluded are required by previous orders of the Commission or federal law. The Commission should require that in future PBR applications, the Company must include all projects during the MYRP period that will be necessary under the Company's most recently filed Carbon Plan or to comply with federal law.

A. <u>The Company should be required to include all Carbon Plan projects that will be necessary during the MYRP period.</u>

The Company failed to include many Carbon Plan related projects from the MYRP. This includes many projects that were included in the Carbon Plan's near-term action plan that will necessarily fall within the MYRP period. The Company claims that the MYRP transmission projects were selected to "provide the greatest value to customers." (Tr. vol. 8, 280) As described above, the Company's cost-benefit analysis focused on a very narrow set of benefits that does not fully capture value to customers.

There are numerous examples of these missing projects. The MYRP "did not include any transmission projects designed to access the onshore and offshore wind resources identified in the Carbon Plan." (Tr. vol. 15, 340) None of the transmission projects identified by Duke in its MYRP are "related to the retirement of other DEC coal units considered in the Carbon Plan for HB 951 compliance," aside from the Allen units which was "already planned by 2024 and were not optimized in the Carbon Plan." (*Id.* at 341-42) The ability to implement these transmission projects was the Company's key rationale for "delaying certain coal retirements beyond their economically optimal retirement dates" during the Carbon Plan proceeding. (*Id.* at 342) Company witness Maley further acknowledges that the Company "cannot identify with certainty" whether the MYRP transmission projects would require a certificate of environmental compatibility and public convenience and necessity (CECPCN). (Tr. vol. 8, 297)

These projects are critically important to achieving the State's carbon emissions reductions targets. The Company is presumably already working towards many of the projects identified in the near-term action plan and, therefore, there is no justification for their absence from the MYRP. The Commission should ensure that this omission does not occur in future PBR applications.

B. The Company should include all projects required under federal law in its MYRP.

The Company failed to include projects that it will be required to implement during the MYRP in order to comply with federal law. As discussed above, failure to include projects within the MYRP means that those projects are not subject to the same cost containment incentives as those included in the MYRP. Similarly, this failure disguises the potential for rate shock when the subsequent rate case is filed, causes financing costs to be incurred, and lowers the likelihood that the earning sharing mechanism will be triggered. An example of this type of project is the implementation of Ambient Adjusted Ratings (AARs) by 2025 under Federal Energy Regulatory Commission Order 881. The Company filed comments with FERC stating that implementing AARs "would require fundamental software changes that would take millions of dollars and several years to complete." (Tr. vol. 15, 318) Nevertheless, the Company did not include any AAR-related investments during the MYRP. (*Id.* at 318-19) The Company is presumably already working towards projects that will be necessary to comply with federal law during the MYRP period and, therefore, there is no justification for their absence from the MYRP. The Commission should ensure that these omissions do not occur in future PBR applications.

CONCLUSION

For the reasons discussed in this post-hearing brief, the AGO respectfully recommends that the Commission do the following:

1. Approve a return on equity of 9.35%;
2. Deny the Company's request to include Hazard Tree Removal as an MYRP Project;
3. Deny the Company's request to exclude revenues from electric vehicles from the residential decoupling mechanism until those revenues can be accurately measured and verified;
4. Institute a hard cap on decoupling surcharges of 3% and lower the rate applied to the carrying charge to the Company's risk-free rate;
5. Modify the demand-side management and energy efficiency mechanism to prohibit the recovery of net lost revenues for residential demand-side management and energy efficiency programs;
6. Modify the demand-side management and energy efficiency mechanism to implement the AGO's proposed Peak Load Reduction PIM;
7. Reject the Company's proposed Renewables Integration and Encouragement PIM;
    a. If Metric A is adopted, modify the PIM to incentivize the interconnection of all types of DERs;
    b. If Metric A is adopted, modify the PIM to incentivize the total capacity installed rather than number of interconnections;
8. Adopt the AGO's proposed Carbon Emissions Reduction PIM;

9. Adopt the AGO's proposed Fuel Source Return on Equity Differentiation PIM;
10. Reject the Time-Differentiated and Dynamic Rate Enrollment PIM;
11. Order the Company to initiate a default TOU pilot program to include the costs and benefits of implementing default TOU rates consistent with the design recommendations discussed herein;
12. Order the tracking of additional metrics identified in the testimony of AGO witness Balakumar and discussed herein;
13. Shift the Summer On-Peak period in the Company's proposed TOU rates one hour earlier to better account for system costs and LOLE;
14. Order the Company to design and file for approval a Critical Peak Pricing rate for non-residential customers;
15. Reduce demand charges in the proposed OPT-V and HLF tariffs with corresponding increases to the energy charges;
16. Increase the discount rate for OPT-V and HLF customers to meet or exceed marginal costs;
17. Order the Company to modify its proposed Rider NSC to allow:
    a. Customers to enroll for a contract term of up to five years;
    b. Customers to retain any renewable energy credits generated by their rooftop solar;
18. Order the Company to pursue cost saving strategies related to its MYRP transmission projects, including:
    a. Studying grid-enhancing technologies;

b. Evaluating regional transmission projects; and

19. Direct the Company in future PBR applications to include in its list of MYRP projects:

    a. Projects required to be completed during the MYRP period by the Company's most recent Carbon Plan;

    b. Projects required to be completed during the MYRP period by federal law.

Respectfully submitted this the 11th of October, 2023.

JOSHUA H. STEIN
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CERTIFICATE OF SERVICE

The undersigned certifies that he has served a copy of the foregoing POST-HEARING BRIEF OF THE NORTH CAROLINA ATTORNEY GENERAL'S OFFICE upon the parties of record in this proceeding by email, this the 11th day of October, 2023.

/s/ Derrick C. Mertz
Derrick C. Mertz
Special Deputy Attorney General