BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1300

In the Matter of:	)	**POST HEARING BRIEF OF NORTH**
	)	**CAROLINA JUSTICE CENTER,**
Application of Duke Energy	)	**NORTH CAROLINA HOUSING**
Progress, LLC for Adjustment of	)	**COALITION, SOUTHERN**
Rates and Charges Applicable to	)	**ALLIANCE FOR CLEAN ENERGY,**
Electric Service in North Carolina	)	**NATURAL RESOURCES DEFENSE**
and Performance-Based Regulation	)	**COUNCIL, AND VOTE SOLAR**

PURSUANT to North Carolina Utilities Commission (NCUC or Commission) Rule R1-24 and the instructions of the Chair at the close of the evidentiary hearing in this matter on May 16, 2023, the North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Vote Solar (NCJC, *et al.*), respectfully submit this brief to the Commission on certain issues in the above-captioned docket.

INTRODUCTION

Under N.C. Gen. Stat. § 62-133.16, an electric public utility filing a performance-based regulation (PBR) application has the burden of proving that the application would result in just and reasonable rates, is in the public interest, and is consistent with PBR statutory criteria and the Commission's PBR rules. Duke Energy Progress, LLC (DEP) has not met its burden of proof. It seeks approval for a roughly $1.4 billion spending spree to support a continuation of its old Power/Forward and Grid Improvement Plan projects, a sprawling swath of poorly planned, poorly justified capital distribution projects that are scant on guardrails and offramps. Tr. vol. 21, 839-40. DEP has not provided sufficient data to assure the Commission that this elevated level of capital spending would provide sufficient customer benefits to justify the cost. DEP has also failed to present enough evidence that this spending is sufficiently tied to the Carbon Plan or to other compelling North Carolina policy goals.

Ultimately, DEP's PBR application seeks to re-allocate standard, longstanding utility risks from DEP to its customers. The application seeks to lock-in the proposed rate increases over the next three years and effectively immunize

DEP from further scrutiny through the three-year rate case moratorium provided in N.C.G.S. § 62-133.16(f). The innovative PBR mechanisms established under N.C.G.S. § 62-133.16 (HB 951) have their place and purpose. However, DEP has not proven that its unprecedented levels of planned distribution grid spending meet that place or purpose. Instead, there is risk that these costly, unnecessary grid investments will fail to advance the deployment of additional distributed energy resources and crowd out the capital investments that DEP will need to make to accelerate retirement of fossil fueled generation assets and deploy replacement resources that comply with the carbon reduction requirements in HB 951. When considered in tandem with DEP's planned non-MYRP capital spending over the next three years, DEP customers could see their rates double by the next rate case. Tr. vol. 16, 487. That many of these capital investments would be subject to DEP's proposed 10.4% return on equity (ROE), which is 80 basis points more than an already inflated electric industry average, is further insult to injury.

It is imperative that the Commission reject DEP's PBR application. At bottom, DEP has failed to demonstrate that its PBR application would improve upon traditional cost of service ratemaking. If the Commission were to approve a multiyear rate plan, it should incorporate NCJC, *et al*. witnesses David Posner, David Hill, and Jake Duncan's proposed modifications. Specifically, the Commission should adopt witness Posner's performance incentive mechanism (PIM) modifications and his three alternative PIM proposals, approve witnesses Hill and Duncan's proposed non-wires alternative (NWA) demonstration projects, and require DEP to modify its multi-year rate plan (MYRP) distribution system investments to incorporate potential federal tax savings.

In addition, the Commission should initiate an investigation into distribution system planning to establish stakeholder supported modifications to DEP's distribution planning framework, require DEP to track system reliability at the zip code or census tract level, adopt witnesses Hill and Duncan's other recommendations to improve DEP's distribution system planning, spending, and stakeholder engagement, and convene a policy goals docket to support the development and refinement of robust PBR policy goals.

Finally, regardless of the Commission's decision on the PBR application, the Commission should reject DEP's excessive ROE proposal. Instead, the Commission should adopt the recommendation of NCJC, *et al*. witness Mark Ellis, who has demonstrated that authorized ROEs for electric public utilities have gotten out of sync with the actual cost of equity. His approach, using unbiased assumptions and inputs, results in an estimated cost of equity of 6.0%, optimized with an equity ratio of 58%, which would allow DEP to maintain its current bond rating, fairly compensate DEP's equity investors, and result in substantial savings for DEP's customers, $370 million below DEP's initially proposed revenue requirement. As further protection for DEP's most vulnerable, low-income customers, NCJC, *et al*. urges the Commission to approve the Affordability Settlement, which is not contingent on the Commission approving the PBR application.

ARGUMENT

I. Rates Set by the Commission Must Be Just and Reasonable

In the Public Utilities Act, the North Carolina General Assembly declared that it is the policy of the state to provide "fair regulation of…utilities in the interest of the public" and "just and reasonable rates and charges for public utility services." In light of these core principles, the North Carolina Supreme Court has ruled that "[t]he primary purpose of [the Public Utilities Act] is . . . to assure the public of adequate service at a reasonable charge." *State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 285 N.C. 671, 680, 208 S.E.2d 681, 687 (1974).

In furtherance of this statutory purpose, the Commission is vested with the authority to set rates for public utilities consistent with the policies of the Act. N.C.G.S. § 62-2(b); *see State ex rel. Utils. Comm'n v. Edmisten*, 294 N.C. 598, 606-07, 242 S.E.2d 862, 868 (1978) (holding that the Public Utilities Act empowers the Commission to effectuate the public policies established by the Act).

In setting rates for public utilities, the burden of proof is on the utility to show that its proposed rates are just and reasonable. N.C.G.S. § 62-75; *State ex rel. Utils. Comm'n v. Cent. Tel. Co.*, 60 N.C. App. 393, 394, 299 S.E.2d 264, 265 (1983). The United States Supreme Court has held that "the fixing of 'just and reasonable' rates . . . involves a balancing of the investor and the consumer interests." *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603, 64 S. Ct. 281, 288 (1944). Consistent with the Supreme Court's command, the Public Utilities Act specifies that "the Commission shall fix such rates as shall be fair both to the public utilities and to the consumer." N.C.G.S. § 62-133(a). This provision of the Act "emphasize[s] that fairness to customers is a critical consideration in rate cases by including a directive that 'the Commission shall fix such rates as shall be fair both to the public utilities *and to the consumer*.'" *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 495, 739 S.E.2d 541, 548 (2013) (emphasis in original) (quoting N.C.G.S. § 62-133(a)). Accordingly, the Commission must consider the impact on customers in determining whether DEP's proposals to increase its rates and charges in this case are just and reasonable.

With respect to PBR applications, the applicant utility must demonstrate that its proposed PBR mechanisms "would result in just and reasonable rates, is in the public interest, and is consistent with the criteria established in [HB 951] and rules adopted thereunder." N.C.G.S. § 62-133.16(d)(1). In reviewing a PBR application, the Commission must determine whether the application does the following: (1) "[a]ssures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric public utility and to the customer"; (2) "[r]easonably assures the continuation of safe and reliable electric service"; and (3) "[w]ill not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or 'rate shock' to customers." *Id.*

II. The Commission Should Reject DEP's Excessive Distribution Spending Over the Next Three Years and Require More Robust Consideration of Less Expensive Non-Wires Alternatives and the Environmental Justice and Bill Affordability Implications of Its Grid Planning.

Ever since Duke announced its $13 billion Power/Forward initiative for grid spending in 2017, the Company's plans have met with near universal skepticism—if not outright condemnation. Six years later, the Commission is yet again confronted with these old plans for massive spending on distribution grid projects. Yet a lot has changed since 2017. It is long past time for Duke's plans to change as well.

Distribution grid projects make up the single largest capital spending item in DEP's rate case application. When considering planned spending in the MYRP and planned capital spending over the next three years outside of the MYRP, DEP is planning to spend $3.871 billion on distribution grid projects over the next three years (46% of MYRP projects and 40% of non-MYRP projects). Tr. vol. 16, 472-74, Table 8. That spending is in addition to the $1.446 billion in distribution plant in the base general rate case (43% of the total capital in the base rate case). Tr. vol. 16, 444, Table 4; 472, Figure 18.

The principal benefit Duke used to justify these billions of dollars in capital spending are reliability improvements. But—consistent with its mandate to provide service—Duke already provides adequate levels of reliability. Public Staff witness Dustin Metz summed up the crux of the issue in his direct testimony: "It is shocking that maintaining or improving the overall reliability of the Company's entire electric system requires nearly a $9 billion dollar capital project spend by the end of Rate Year 3 (September 2026)." Tr. vol. 16, 486-87. Duke's bloated plans for grid spending are particularly frustrating given its failure to reasonably consider non-wires alternatives, particularly multiple distributed energy resource alternatives, for any of its distribution grid upgrades. Instead, it has arbitrarily established a single test for batteries as the sole possible non-wires alternative that it would consider. Nor has DEP considered any of the distributional effects of its grid spending, and thus, has no way of knowing whether its grid improvements are equitably benefiting ratepayers along racial or income lines.

NCJC, *et al*. witnesses David Hill and Jacob Duncan documented fundamental deficiencies with DEP's distribution grid planning. Their testimony demonstrates that there are likely more cost-effective ways for DEP to transform its grid to accommodate more distributed generation, electric vehicles, and comply with carbon plan requirements. As noted by NCJC, *et al*. witness Posner, the PBR framework in DEP's application does not go far enough to mute the old cost-of-service incentives that dampen DEP's appetite for more cost-effective non-wires alternatives. Tr. vol. 21, 1122-23. Simply put, DEP's capital spending inordinately serves as a vehicle to increase potential for shareholder returns. Nothing in the pending PBR application serves as an adequate check on that incentive.

Making matters worse, there was insufficient time for interveners to thoroughly vet DEP's many distribution grid projects. As explained by Public Staff witnesses Metz and McLawhorn, DEP's PBR application was effectively four rate cases consolidated into one, with only thirty extra days provided for by statute between filing and the Commission's decision. Tr. vol. 17, 26-27. And given that nearly half of all of DEP's capital spending in the general rate case, the MYRP, and in non-MYRP projects is for numerous distribution grid projects, there was not enough time or staff resources for the Public Staff or intervenors to sufficiently vet DEP's application.

Stakeholder criticism and intervenor opposition to these extraordinary levels of spending on the distribution grid have not yet dissuaded Duke from continuing with these unsustainable levels of spending. The Commission is the only entity that can direct Duke, in no uncertain terms, that this level of spending is not affordable for North Carolina's ratepayers, has not been justified as necessary for maintaining system reliability, and is not required under North Carolina law (for carbon plan compliance or otherwise). The carbon reduction mandates of HB 951 will require significant levels of capital investment from the Company in the coming years. And while NCJC, *et al*. anticipate long-term savings for customers from many of those investments in renewable resources, there will be upfront costs borne by ratepayers. It is not reasonable or prudent to crowd out that future required capital spending for discretionary grid improvements of dubious value over the short term.

Given Public Staff witness Metz's estimate of the revenue impact of the Company's planned capital spending over the next three years, "current rates will approximately double between now and the end of the Company's next rate case." Tr. vol. 16, 487. The Commission cannot allow this potential doubling of rates to come to pass.

NCJC, *et al*. recommend that the Commission reject DEP's MYRP application and open an investigation into distribution system planning with stakeholder input to determine: (1) grid modernization objectives, (2) reporting and data sharing requirements; (3) non-wires alternatives methodology; (4) community engagement plan; and (5) environmental justice (EJ) aspects of grid modernization. Tr. vol. 21, 876.

A. DEP's Planned Distribution Grid Modernization Projects Mirror Their Old Plans, Despite New Policy Directives in North Carolina.

The grid distribution projects that DEP is seeking to include in rate base in this case are continuations of Duke's old Power/Forward and Grid Improvement Plan projects. Tr. vol. 21, 834, 856-69. These plans were initiated with minimal stakeholder engagement. But since these old grid spending plans were announced starting in 2017, North Carolina has adopted the carbon reduction requirements in HB 951. *Id.* at 834-35. It is inevitable that these new policy demands will have a significant impact on Duke Energy's capital investments in North Carolina in the coming years. But in this rate case, DEP plans to continue with its old Power/Forward and Grid Improvement Plans without any significant course correction. If done well, grid modernization projects "can facilitate the integration of DERs and lower the overall cost of" complying with the carbon reduction mandates of North Carolina law. *Id.* at 835. But if done poorly, those grid spending projects "may increase . . . compliance costs without delivering comparable benefits to ratepayers." *Id*. As will be shown in more detail below, DEP has done poorly. Its distribution grid spending plans fail to consider the distributional effects on environmental justice communities and do not put North Carolina on a path towards least-cost carbon plan compliance.

1. *The distribution grid spending is just a continuation of the reviled Power/Forward and GIPs.*

The majority of the distribution grid projects included in DEP's application—in the general rate case, the MYRP, and planned projects that lie outside of the MYRP over the next three years—are continuations of the Company's

Power/Forward and GIPs. Tr. vol. 21, 856. Power/Forward was a plan announced in 2017 to spend $13 billion over 10 years on the grid in the Carolinas. Duke Energy announced its Power/Forward plans before conducting any stakeholder engagement. *Id.* at 858. The distribution grid plans in 2017 included significant spending on self-optimized grid, grid hardening and resilience, system intelligence and communications upgrades, and targeted undergrounding. *Id.* at 857.

The Public Staff and intervenors expressed significant concerns with DEP's stated plans when Power/Forward was first announced in the 2017 rate case. Tr. vol. 21, 858-59; *Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase*, In the Matter of Application by DEP for Adjustment of Rates and Charges, Docket No. E-2, Sub 1142, at 97-99 (Feb. 23, 2018) (hereinafter Sub 1142 Order). These witnesses noted several problems, including the lack of an adequate cost-benefits analysis, DEP's failure to provide for stakeholder input, its potential impact on customer rates, and DEP's insufficient efforts to optimize its plans or otherwise take advantage of best practices for grid modernization in a way that would lead to customer benefits. *Id.* Because DEP was not seeking cost-recovery for Power/Forward in the 2017 rate case, the Commission was not in a position to rule on the reasonableness or prudence of Duke Energy's plan. *Id.* at 99. However, the Commission concluded that DEP "has not yet provided compelling evidence that the proposed grid investment plan will result in meaningful benefits to ratepayers despite its cost." *Id.* at 99-100.

Duke Energy hosted a series of three stakeholder meetings on its Power/Forward plans following the Sub 1142 Order. Tr. vol. 21, 861-65. At around the same time, Duke rebranded Power/Forward as the Grid Improvement Plan, or GIP. *Id.* at 861. Many participants expressed frustration with the Company's meetings, largely because Duke had already established its fundamental goals and grid projects before engaging with stakeholders, providing little opportunity for feedback to meaningfully influence Duke's plans. *Id.* at 862-65. The only stakeholder meeting relating to Duke's grid modernization projects since July of 2021 was an integrated system and operations planning (ISOP) meeting in February of 2023. *Id*. at 870. As in the Power/Forward and GIP meetings that preceded this ISOP meeting, Duke again presented a "fully baked strategy" and finalized methodologies without space for co-creation of grid planning. *Id.*

Little changed between Power/Forward and GIP. As noted by witnesses Hill and Duncan, about 80% of the GIP filing in 2019 was made up of programs described in the Power/Forward proposal. *Id.* at 865. DEP has acknowledged that there is considerable overlap in distribution grid project categories between Power/Forward, GIP, and the Company's MYRP distribution projects. Tr. vol. 10, 285-300; NCJC, *et al*. Cross Examination Guyton/Maley Direct Rebuttal Ex. 3 (Official Ex. vol. 10).

In the current case, the overwhelming majority of distribution grid modernization projects are continuations of Power/Forward, GIP, or both. Tr. vol. 21, 868-69. When asked explicitly how DEP had changed the substance or content of its Grid Improvement Plan as a result of stakeholder feedback since the 2019 rate case, it could not identify any specific changes. Tr. vol. 10, 282-83; NCJC, *et al*. Cross Examination Guyton Maley Direct Rebuttal Ex. 1 (Official Ex. vol. 10).

The overlap between Power/Forward, GIP, and the related distribution projects in the MYRP proposal advancing capacity expansion "demonstrate that the majority of the Company's distribution MYRP programs is related to its narrow and outdated historical approach to grid modernization and planning and do not reflect best practices or stakeholder input." Tr. vol. 21, 874-75.

Much like the GIP projects put forward in the 2019 rate case, the principal benefits that DEP has identified for this enormous spending program are marginal reliability improvements. *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice*, In the Matter of Application by DEP for Adjustment of Rates and Charges, Docket No. E-2, Sub 1219, at 122 (Apr. 16, 2021) (hereinafter Sub 1219 Order). At the same time that DEP argues that "marginal reliability improvements" are the principal benefit for this large amount of distribution grid spending, it "affirms that it is maintaining adequate, reliable service for its customers." Tr. vol. 21, 842. Any potential material benefits from additional, marginal reliability improvements, particularly for residential customers, do not appear to be worth the cost. *Id.*

As the Commission noted in the Sub 1219 Order, the Public Staff expressed concern that "a majority of the benefits identified in DEP's cost-benefit analyses were estimates of the financial benefits customer would receive by avoiding power outages." Sub 1219 Order at 122. And 97% of the actual financial benefits from reduced outages "would accrue to commercial and industrial customers." *Id.* DEP's method for cost-benefit analysis, however, has not substantially changed in the interim. The majority of the savings used to perform the cost-benefit analysis "are for customer benefits of avoiding an outage using the DOE's calculator." Tr. vol. 10, 301. The majority of the monetary benefits from reduced frequency or duration of outages flow to nonresidential customers. *Id.* at 305. And each GIP or MYRP distribution grid project is considered in isolation under DEP's cost-benefit approach. *Id.* at 303-04.

With respect to DEP's cost-benefit framework used to justify its massive scope of spending, witnesses Hill and Duncan noted the following significant problems:

- Anticipated reduced outage benefits of each program are considered in isolation, so that benefits from one program are considered as if other distribution grid investments were not simultaneously occurring, resulting in potential double counting.
- DEP's cost-benefit framework fails to weigh the rate impacts on residential customers from this high level of spending on distribution grid projects against the non-monetary benefits of marginally reduced outages to those same residential customers, who will shoulder a disproportionate burden of cost-recovery for those projects.
- Failure to consider the potential for third-party NWAs to defer or completely avoid the need for some of DEP's proposed grid projects, particularly where those customer-sited investments could result in customer bill savings as well.

- Failure to consider the interplay of the IRA, which provides incentives that make customer-sited investments much more affordable and could put downward pressure on rates.

Tr. vol. 21, 846-49. To remedy these shortcomings in DEP's myopic cost-benefit methodology, the Commission should convene a working group to consider a more comprehensive cost-benefit framework, drawing from the National Energy Screening Project. *Id.* at 849.

The Public Staff, NCJC, *et al*., and some additional intervenors agreed to deferral accounting treatment for a smaller subset of GIP projects (that were focused on renewable integration) in the 2019 rate case. *Id*. at 866. While the Commission accepted that stipulation and limited total deferral accounting treatment for GIP projects to $400 million, DEP did not in fact limit its grid spending in the interim years to just those more limited projects. The Commission's Sub 1219 Order noted that its deferral order was designed to "provide an incentive for DEP to manage its GIP spending cost-effectively and mitigate the risk of over-spending." *Id.* at 140-41. But as it turns out, the Stipulations failed to mitigate the risk of DEP overspending on distribution grid projects under its GIP plans.

B. Deficiencies in DEP's Distribution Grid Plans

1. Too expensive, stale and incomplete project support documentation, and DEP likely lacks capacity to complete projects.

The Public Staff noted extensive concerns with the priorities, scope, staffing, and most of all expense of DEP's distribution grid spending. From 2019 to 2022, DEP spent $2.884 billion of its total capital spending on distribution grid projects. Tr. vol. 16, 485, Table 10. From June 2020 to November 2022, capital distribution expenditures made up the single largest category of DEP's capital spending: 43% of the total (the next largest category, transmission, was only 17%). *Id*. at 472, Figure 18. An updated analysis of historic spending from June 2020 through February of 2023 indicates that DEP spent $1.8 billion on distribution plant. *Id*. at 508. That amount is projected to increase over the course of the next three years, with $3.871 billion in capital expenditures for distribution grid projects in both MYRP and non-MYRP projects. *Id.* at 474-75, Table 8; *id*. at 486, Table 11.

As is true with the historic spending in this docket, distribution capital spending is the single biggest category by far over the next three years: for the MYRP, distribution projects will make up nearly half of all capital projects, or 46%, and for non-MYRP planned capital spending (shadow MYRP), 40% will be made up of distribution grid projects. *Id.* at 473-74. Combined, 43% of all capital spending over the next three years will be on distribution grid projects. *Id*.

To put the Company's planned capital spending over the next three years in context, both MYRP and shadow MYRP capital spending is expected to total about $9 billion, about three times more than the Company is seeking in cost recovery for capital projects closed to plant from June 2020 to November of 2022. *Id.* at 474-75. As expensive as these planned distribution grid projects are, those estimates were often out of date and may not fully account for recent inflation. The Public Staff noted that some of the cost estimates for projects in DEP's MYRP were multiple years old and that many project estimates were completed in the spring of 2022. Tr. vol. 16, 461; tr. vol. 17, 38-39.

While not all of DEP's historic or planned distribution spending is related to Power/Forward or GIP, it is apparent that the unprecedented levels of distribution grid spending are attributable to DEP's grid modernization efforts. An analysis of revenue impacts from DEP's application by NCJC, *et al*. witnesses Hill and Duncan highlighted the cumulative and additive nature of the GIP-related distribution spending projects in the MYRP. When adding the GIP-related distribution projects from base revenues to Rate Years 1 through 3, witnesses Hill and Duncan identified about $1.417 billion in revenue requirements from GIP projects over the next three years. Tr. vol. 21, 839-40. They found that 72% of DEP's proposed MYRP distribution grid projects are continuations of Power/Forward and/or GIP projects. *Id.* at 874. When also considering traditional distribution grid spending on top of the GIP-related projects, these significant planned expenditures merit "careful regulatory oversight, and comparison with alternatives." *Id.* at 841.

The Public Staff has expressed alarm over these capital spending plans: "It is shocking that maintaining or improving the overall reliability of the Company's entire electric system requires nearly a $9 billion dollar capital project spend by the end of Rate Year 3 (September 2026)." Tr. vol. 16, 486-87. Given Public Staff's "estimate of the revenue impact of the Company's MYRP and non-MYRP spend over the next three years, current rates will approximately double between now and the end of the Company's next rate case." *Id.* at 487. Though Public Staff witness Metz was referring to all of DEP's planned capital spending in these portions of his testimony, distribution spending is by far the single biggest component of that gargantuan capital spending, so it would be appropriate for the Commission to focus on limiting that spending.

In addition to serious concerns about the overall amounts of capital spending that DEP is planning over the next three years, the Public Staff testified that it had concerns about whether the Company is pursuing appropriate priorities. After noting deterioration in the reliability of DEP's fossil generation plant, Public Staff witness Metz expressed concern about DEP's "spending priorities among business groups in the MYRP, given decreasing SAIDI numbers. . .concurrent with negative trends in coal and natural gas generating unit performance." Tr. vol. 16, 444-45. Recognizing that decreasing SAIDI, which indicates improving reliability, is related to DEP's principal justification for its grid improvement plan, witness Metz was concerned about whether DEP was truly optimizing across its different business units for maintaining system reliability generally. Tr. vol. 17, 35-36; tr. vol. 16, 481-82 ("Company's projected spending in the MYRP appears to be skewed toward improving SAIDI, a reliability metric that is already improving"); Tr. vol. 21, 661-62 (CUCA witness O'Donnell noting that the purpose of GIP is to reduce the frequency and duration of outages on the Duke system); Tr. vol. 21, 221-25 (Public Staff witness Thomas Williamson discussing his analysis of improving SAIDI numbers for DEP). Witness Metz was "unable to identify how the Company determined the total capital spend for each business group (Distribution, Transmission, Steam, etc.) per Rate Year based on discovery in this case." Tr. vol. 16, 481. The Public Staff concluded that the quality of service provided by DEP to its retail customers is adequate. Tr. vol. 21, 235.

The Public Staff also expressed serious reservations about DEP's "ability to meet necessary staffing levels to complete its proposed MYRP projects." Tr. vol. 16, 465. For example, to carry out its vast number of costly distribution projects, DEP would need to increase internal staffing by over 50% in the coming year. *Id.* at 467. Public Staff determined that DEP does not have a viable plan to staff its "planned MYRP work while continuing to perform traditional work" other than relying on contracting in the outside market, exposing DEP to potentially higher cost premiums. Tr. vol. 16, 466, 470. This exposes DEP and its customers not only to increased cost risk, but also execution risk. *Id.*

An additional execution risk identified by the Public Staff is DEP's failure to identify equipment that will be needed to execute its MYRP projects and that will either take more than six months to procure or that costs over $150,000. *Id.* at 479. Given these staffing and planning concerns, witness Metz lacked confidence that DEP could complete the MYRP projects it has planned in each rate year. *Id.* At the end of the day, the lack of information regarding DEP's staffing and logistical preparation prevented Public Staff and other intervenors from thoroughly vetting DEP's projects. *Id.* "An MYRP should not be a blank check for the Company to do as it determines without any oversight." *Id.* The Commission should agree with the concerns raised by the Public Staff with the lack of sufficient information justifying the "<u>need</u> for the project and whether the Company has the <u>ability</u> to complete it, including the costs, staffing, and timeliness, as well as a risk analysis" in the MYRP application. *Id*.

In sum, based on the Public Staff's review alone, DEP's distribution- project heavy MYRP should not be approved. It is too expensive for DEP's customers, threatening to double rates when DEP comes back for another rate case in just three years. Many distribution grid projects lack sufficient detail on staffing, procurement, and basic needs assessment to justify receiving a green light from the Commission. In addition, as shown in the testimony of NCJC, *et al*. witnesses Hill and Duncan, DEP failed to demonstrate optimal distribution grid planning in other respects, providing additional reasons for the Commission to call a time out on DEP's plans.

2. *So-called megatrends skewed towards Duke's capital spending.*

After DEP abandoned the Power/Forward branding, DEP identified what it called "megatrends" to justify its continuation of those projects under the "Grid Improvement Plan" banner. But the Company's selective identification of so-called megatrends failed to consider similarly important trends that would point DEP in different and less costly directions for its grid planning.

Under DEP-designated megatrend 2, DEP witness Guyton considered additional distributed energy resources (DERs) on the grid as "new types of load and resources impacting the grid." Tr. vol. 10, 56; tr. vol. 21, 843. DEP's phrasing suggests that DERs create an additional need for traditional grid investments, even though a planned combination of DERs, such as customer sited solar paired with storage, energy efficiency, and demand flexibility would in fact help to "reduce circuit level capacity constraints and serve as a system level asset." Tr. vol. 21, 843-44. Similarly, under megatrend 3, witness Guyton suggested that public and private incentives and requirements for clean energy resources are driving additional system costs. Tr. vol. 10, 56. But that is only because DEP's grid plans focus on utility-owned assets rather than considering how non-utility investments can be leveraged to provide grid services at lower cost. Tr. vol. 21, 844. As noted by witnesses Hill and Duncan, DEP's choice of how to articulate megatrends 5 and 7 similarly overlook the ways that NWAs, DERs, and vehicle electrification can be used to lower costs and benefit ratepayers. *Id*. at 844-45.

DEP treats "the growth of DERs as a negative impact, for which the sole solution is direct utility investment to enhance grid capabilities," overlooking the "value to the system and to customers of a more integrated and holistic approach to grid planning based on a more balanced portfolio of utility and customer sited assets." *Id.* at 846. DEP's articulation of megatrends also fails to consider the recent trend of federal and state governments tracking the distributional effects of their policies to ensure that environmental justice communities receive a proportionate share of benefits of public investments.

3. Failure to consider less costly alternatives.

DEP's limited and narrow screening of NWAs foreclosed consideration of a range of more cost-effective options for grid investments. DEP only considered battery storage as a potential NWA for addressing capacity constraints. DEP's cost analysis for batteries came from Guidehouse and was only considered for projects with lead times of at least three years and only if it could defer the more traditional "wires" project for at least 10 years. Tr. vol. 21, 850. This approach was not developed with any stakeholder feedback, despite multiple efforts by stakeholders to engage on a shared NWA methodology since the initial Power/Forward meetings. *Id.* at 851.

Witnesses Hill and Duncan noted several improvements to DEP's NWA screening that would take into consideration numerous additional technologies and benefits, informed by best practices in other jurisdictions:

- Include additional resources with capacity deferral potential such as energy efficiency, demand response, and demand flexibility.
- Include additional benefit categories such as resilience, carbon reduction, and customer bill impact.
- Include additional grid needs such as voltage and frequency regulation, and increased hosting capacity.
- Reduce the deferral period.

Tr. vol. 21, 851 (citing PACIFIC ENERGY INSTITUTE, NWA OPPORTUNITY EVALUATION: SURVEY OF CURRENT PRACTICE (2020)).

Though they recommended that additional details be worked out collaboratively with additional stakeholders, witnesses Hill and Duncan noted that these best practices have paid dividends in other jurisdictions. There is every reason to think that, if embraced here, they would similarly result in the identification of less costly alternatives to a wide array of distribution grid projects that leverage energy efficiency and demand response, which have the added benefit of helping to lower customer bills. *Id.* at 851-53. In addition to recommending that the Commission direct Duke to collaborate on an updated NWA methodology, NCJC, *et al*. ask that the Commission order DEP to conduct at least two NWA demonstration projects. *Id*. at 854. At least one of those demonstration projects should be located in an environmental justice community to evaluate how targeted intervention and leveraging of multiple DERs can achieve grid and societal needs simultaneously. *Id*. at 854-55. These demonstration projects would also have the virtue of being complimentary to the NWA PIM recommended in witness Posner's testimony (discussed in Section V.B.). *Id.*

4. Failure to consider distribution grid spending's connection with Environmental Justice.

As noted above, DEP's distribution grid spending is the single biggest category of planned capital spending over the next three years. DEP has failed to properly consider the potential for its spending on distribution grid projects to worsen the energy burdens of those low-income or fixed-income customers who will not otherwise be able to take advantage of bill payment assistance programs. In addition, DEP has failed to consider the distributional effects of its grid spending. To the extent its GIP-related projects are improving system reliability, DEP has not tracked which communities are receiving those benefits and which have not. Without some kind of geographic analysis of those investments, neither the Commission nor DEP can track whether communities of color or low-income households are being disproportionately left out of sharing in those improvements. Tr. vol. 21, 877-81.

To start, the Commission should direct DEP to report reliability data not just at the system-wide level (as is the case for SAIDI and SAIFI metrics), but to report data at the census tract and/or zip-code level. This geographic data could then be mapped onto sociodemographic factors like race or income, to determine whether there are any baseline disparities in reliability. To the extent DEP views its grid modernization efforts as related to its carbon plan requirements, such geographic analysis is consistent with the Commission's Order noting that "[s]uccessful execution of the Carbon Plan requires engagement by Duke on issues related to environmental justice and frontline communities." *Id.* at 881 (quoting *Order Adopting Initial Carbon Plan*, Docket No. E-100, Sub 179, at 42 (Dec. 30, 2022)).

Public utilities in Michigan and Illinois have begun to track grid reliability at the circuit and substation level and then report metrics at the census tract level, which are then mapped onto demographic data to perform an environmental justice analysis. Tr. vol. 21, 881-92. In a DTE Electric rate case, the Michigan Public Service Commission (PSC) found that DTE would not be able to know whether its investments would lead to "equitable energy infrastructure" unless DTE provided data and analyses that track the results of its investments. *Id.* at 882 (citing Order, Case No. U-20836, at 458-459 (Mich. Pub. Serv. Comm'n, Nov. 18, 2022)). The Michigan PSC has since approved a new reliability reporting template that includes circuit level, zip code, and census reporting. *Id.* at 883.

Some initial analysis of DTE Electric's system revealed the potential for unequitable outcomes. For example, a disproportionate number of impoverished, unemployed, and racial minorities who are considered socially vulnerable (under CDC guidelines) are served by DTE's 4.8 kV system as opposed to its 13.2 kV system. The 4.8 kV system is served by older equipment and has lower hosting capacity than the 13.2 kV system. In addition, DTE's hardening and modernization program had so far primarily served higher income census tracts. *Id.* at 884. DTE is now tracking reliability metrics at the customer level, which it then extrapolates to the circuit and substation level. In addition, the utility has developed SAIDI and SAIFI reliability data at the census tract level, which it has then mapped onto EJ communities. *Id.* at 885. The resulting maps demonstrate that there is considerable variation in service reliability in vulnerable census tracts. With this data, the Michigan PSC and DTE can tailor their grid investments to help ensure more equitable outcomes.

Akin to Governor Cooper's Executive Order 246, the Michigan governor issued an executive order requiring executive agencies to consider environmental justice in their decision making. *Id.* at 887. Although the Michigan order does not apply directly to the Michigan Public Service Commission, the Order does direct the environmental agency to comment on environmental justice considerations in integrated resource plan dockets.

In a Commonwealth Edison rate case, Illinois's commission developed performance metrics (akin to PIMs) that include tracking reliability on environmental justice and resiliency metrics. Initial analysis of this data revealed that environmental justice communities experience more frequent and longer lasting outages than their counterparts. *Id.* at 891. DEP does not report any of the data that would be required to determine whether there are similar disproportionate outcomes in its North Carolina service territory. As witnesses Hill and Duncan note:

> Providing reliable service is one of the basic tenants of the regulatory compact. If a certain segment of the customer base is experiencing disproportionately high reliability events, it is the duty of both the Commission and the Company to mitigate the problem. Tracking reliability data at a level more granular than system

> averages can reprioritize Company infrastructure spending and lead to the development of new programs to improve reliability for customers.

Id. at 894. Significantly, DEP *already* tracks reliability data at a level more granular than system averages. Tr. vol. 10, 315-17. In fact, the Company tracks reliability data, including outage history, "down to the protective device for every circuit in the Carolinas, every substation." *Id*. at 316. But the Company, so far, has refused to report that data. And as a result, the Commission and stakeholders have no way to assess "whether certain communities might experience more frequent or longer outages" than others. *Id*. at 316-17. Furthermore, there is already evidence that DEP's distribution grid spending disproportionately benefits commercial and industrial customers while burdening residential customers. Tr. vol. 21, 894. Better data will provide more insight into these important issues.

Lastly, DEP should work with stakeholders to improve its hosting capacity analysis, overlay sociodemographic, energy burden, and other EJ indicators on its planned grid hosting capacity (GHC) map, and include load hosting capacity in its GHC analysis. An effective generation hosting capacity analysis would provide DEP and stakeholders with more insight into whether specific circuits could manage DER without additional investments. Tr. vol. 21, 895. Relatedly, an effective load hosting capacity would measure the ease with which individual circuits could serve electricity demand without additional investments. *Id.* at 899. Improving hosting capacity would significantly benefit EJ communities by supporting DER projects such as community solar. *Id.* at 895. Indeed, evidence from other jurisdictions suggests that low-income communities and communities of color experience disparities in hosting capacity. *Id.* at 898-99.

Unfortunately, while DEP is collaborating with stakeholders to prepare a GHC analysis, it is unlikely this analysis will enable greater visibility into hosting capacity disparities as DEP "is only planning on making an interactive map available." *Id.* at 900 (internal quotation marks omitted). To rectify this issue, DEP should adopt the fourteen key decision point framework that the Interstate Renewable Energy Council (IREC) developed and collaborate with stakeholders in using that framework to identify and address specific areas of improvement in DEP's GHC analysis, work with stakeholders to incorporate sociodemographic, energy burden and other EJ indicators on its GHC map and include load hosting capacity with generation hosting capacity. These measures would help to ensure that DEP's GHC analysis provides real value to the EJ communities who stand to benefit most.

To account for environmental justice considerations in DEP's grid planning, the Commission should:

- Require the Company to report reliability data at the census tract and nine-digit zip code level – comprised of aggregated and anonymized customer premise level data – in order to investigate potential disparities in reliability services.
- This geographic reliability data should be included as a tracking metric in the PBR application.
- The Commission should require the Company to propose a PIM in its next PBR application focused on improving reliability in the census tracts experiencing lower reliability metrics.

- Use its existing GHC stakeholder process to evaluate IREC's fourteen decision point framework for establishing an effective hosting capacity analysis.
- Work with stakeholders to overlay sociodemographic, energy burden, and other EJ indicators on its planned GHC map.
- Include load hosting capacity with generation hosting capacity in its GHC analysis.

III. The Commission Should Approve the Affordability Settlement.

In light of the substantial, unjustified spending in DEP's PBR application, it is even more important that the agreement and stipulation of partial settlement regarding low-income/affordability performance incentive mechanism and affordability issues (Affordability Settlement) entered into between NCJC, *et al*., Sierra Club, Duke Energy Carolinas, DEP, and the Public Staff be approved.

In short, the Affordability Settlement would require the withdrawal of DEP's Low-Income/Affordability PIM; the disbursement of $16 million in aggregate, DEC and DEP shareholder contributions over three years, $10 million of which would support health and safety repairs and $6 million of which would support bill payment assistance through the Share the Light Fund; tracking and reporting how the health and safety repair funds are used; tracking and reporting residential customer payments; the establishment of DEP's proposed Customer Assistance Program (CAP) as a three-year old pilot; and stakeholder collaboration between the stipulating parties and interveners to determine whether the CAP pilot could be transitioned into a tiered discount affordability program. Tr. vol. 22, 99-101.

The Affordability Settlement strikes a fair and appropriate balance in resolving the Company's Low-Income/Affordability PIM, affordability PIM tracking metrics, and CAP. The proposed shareholder contributions will provide bill payment assistance and help unlock additional bill savings for low-income customers by facilitating the home repairs needed to qualify those customers for weatherization assistance. *Id.* at 100. The proposed tracking and reporting requirements will help quantify the number of home repairs and energy burden reductions attributable to this health and safety repair assistance. *See id.*

In addition, the CAP pilot would provide monthly bill payment assistance to approximately 60,000 low-income DEP customers who receive or have been approved to receive Low Income Energy Assistance Program or Crisis Intervention Program assistance. Tr. vol. 12, 205. Moreover, the stipulating parties commit to exploring the benefits and feasibility of transitioning the CAP pilot into a tiered discount affordability program. Tr. vol. 22, 101. The Commission has broad authority to advance generally applicable policy on affordability and energy burden reductions, and the Affordability Settlement advances these policy objectives while minimizing interclass subsidization to the greatest extent practicable by the end of the MYRP period by exerting downward pressure on all rates. *See* tr. vol. 20, 146; tr. vol. 22, 91.

Importantly, the Commission can accept the Affordability Settlement in its entirety as part of its base, general rate case decision while taking other actions to protect North Carolina ratepayers from unaffordable rates. The key levers at the

Commission's disposal are setting an appropriate return on equity and not allowing excessive levels of planned distribution spending by rejecting DEP's MYRP.

IV. The Commission Should Reject DEP Witness Roger Morin's Return on Equity Proposal and Adopt NCJC, et al. Witness Mark Ellis' Proposal Instead.

Notwithstanding the potential of the Affordability Settlement to bring significant relief to some of DEP's most vulnerable low-income customers, the Commission has a broader obligation to ensure affordable rates for all of DEP's customers. One of the most significant drivers of ultimate customer rates that is within the Commission's discretion is the allowed return on equity. The Commission should reject DEP's proposed 10.4% rate of return on equity (ROE) as unreasonable, excessive, and unsupported by the record. An allowed ROE that is based on actual investor return expectations for investments of commensurate low risk can be substantially lower than DEP's proposal, saving DEP's customers hundreds of millions of dollars without damaging the Company's credit rating or ability to attract capital.

A. Legal Standard Requires Setting the Lowest Possible Allowed Return on Equity While Still Being Fair to Investors.

Under Chapter 62, "the General Assembly conferred [on the Commission] 'broad powers to regulate public utilities and to compel their operation in accordance with the policy of the State....'" *State ex rel. Utils. Comm'n v. Carolina Water Serv., Inc. of N.C.*, 225 N.C. App. 120, 133–34, 738 S.E.2d 187, 196 (2013) (quoting *State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n*, 123 N.C. App. 623, 625, 473 S.E.2d 661, 663 (1996)).

When it comes to setting the authorized return on equity, the Commission is required to "meet the twin goals of assuring sufficient shareholder investment in utilities while simultaneously maintaining the lowest possible cost to the using public for quality service." *State ex rel. Utils Comm'n v. Carolina Util. Customers Ass'n, Inc.*, 348 N.C. 452, 458, 500 S.E.2d 693, 698 (1998). These twin goals for setting the authorized rate of return are set forth in the Public Utilities Act. N.C.G.S. § 62-133(b)(4) (providing that when the Commission fixes the rate of return, it is required to consider the ability of the public utility to compete for capital on terms that are reasonable and that are fair to its customers and investors). "The origin of this statute supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of" the Due Process Clauses of the state and federal Constitutions. *State ex rel. Utils. Comm'n v. Duke Power Co.*, 285 N.C. 377, 388, 206 S.E.2d 269, 276–77 (1974) (citing *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 600-05 (1944)).

Being fair to investors, however, is not the same as guaranteeing current market prices for stocks in the parent company of a regulated public utility. "The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid." *Hope*, 320 U.S. at 601. Equity investors take the risk that a utility "might possibly at some time because of market conditions be required to issue shares at less than book value," and it is not the Commission's responsibility to protect investors from that outcome. *State ex rel. Utils. Comm'n v.*

Pub. Staff-North Carolina Utils. Comm'n, 322 N.C. 689, 699, 370 S.E.2d 567, 573 (1988).

The Commission is "free, within the ambit of [its] statutory authority," to make pragmatic adjustments when determining the lowest reasonable rate that would be fair to customers and investors. *Fed. Power Comm'n v. Nat. Gas Pipeline Co. of Am.*, 315 U.S. 575, 586 (1942). The Constitution does not bind the Commission "to the service of any single formula or combination of formulas." *Id.* There is no mathematical formula that the Commission can rely on to produce a precise allowed ROE for DEP in this case. Instead, the Commission must use its own judgement to properly estimate the cost of equity capital that will fairly compensate investors, based on expectations for companies of commensurate risk profiles, while at the same time protecting customers from unreasonable rates. *See also State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n*, 322 N.C. at 697, 370 S.E.2d at 572 (Setting the allowed return on equity is "essentially a matter of judgment based on a number of factual considerations which vary from case to case").

In this case, DEP has not met its burden of proof to justify its requested 10.4% authorized ROE with a capital structure of 53% equity*. See generally State ex rel. Utils. Comm'n v. Duke Power Co.*, 285 N.C. 377, 389, 206 S.E.2d 269, 277–78 (1974) ("the burden is upon Duke to establish the reasonableness of the rate increases it has proposed"); N.C.G.S. §§ 62-75; 62-134(c). To support its claim that a 10.4% ROE is the lowest figure that would satisfy the needs of investors under applicable legal standards, DEP relied exclusively on the testimony of Dr.

Roger Morin. His estimate of the cost of equity, however, rests on assumptions that unreasonably bias his results upwards. Just as importantly, witness Morin ignored the reality that investors are generally expecting lower returns from the equity markets than he asserts that they would "require" from public utility stocks, which are less risky than the broader equity markets. Finally, witness Morin's testimony is plagued by inconsistencies and contradictions with his published work that undercut the credibility of his recommended ROE.

As a witness for regulated electric public utilities before state public utility commissions over the last several decades, witness Morin has recommended unreasonably high ROEs. The ultimate allowed ROE set by those commissions is on average 100 basis points lower than witness Morin's original recommendations. Witness Morin presented no evidence that the resulting lower ROEs impacted the ability of those electric public utilities to obtain capital on reasonable terms or that their financial integrity had been impacted by those decisions.

Intervenor evidence on the authorized rate of return and capital structure, particularly testimony offered by NCJC, *et al.*, the Public Staff, Carolina Utility Customers Association (CUCA), and the Department of Defense and all other Federal Executive Agencies (DoD/FEA) further demonstrate the unreasonableness of DEP's proposed 10.4% ROE. Based on a review of the complete record, a reasonable floor for the authorized ROE is 6%, which reflects the most accurate estimate for the actual cost of equity for enterprises of commensurate risk to DEP. Witness Ellis's recommended ROE would save DEP's customers $370 million per year (from DEP's original proposed revenue requirement) while allowing DEP to maintain its current A2 credit rating.

B. Evidence That Regulated Public Utilities Allowed Returns on Equity Significantly Exceed the Cost of Capital.

The Commission's decision on authorized ROE has a substantial effect on the overall affordability of essential electric public utility service for DEP's ratepayers. Under DEP's original application, its proposed combined rate of return on capital, grossed up for taxes, accounted for more than 25% of its revenue requirement. Tr. vol. 21, 1068. If the Commission-authorized return on equity is set at an amount that is greater than the actual cost of equity capital, wealth is transferred from ratepayers to shareholders. Tr. vol. 8, 268, 314.

Witnesses Ellis and Morin agree that the authorized rate of return on equity should be set equal to the cost of equity capital. Tr. vol. 8, 252; tr. vol. 21, 942. Where they differ is on how to accurately estimate the cost of equity. And while witness Morin insisted that cost of equity is equal to the return on equity, the two figures are distinct in ways that can inform the Commission's analysis of the appropriate authorized ROE. Tr. vol. 8, 206. Return on equity is an accounting measure that can be reported on a company's financial statement and is equal to net income divided by the book value of equity. *Id.* at 252. Cost of equity, in contrast, has to be estimated and is based on the returns investors expect from investments of commensurate risk. *Id.* Though witness Morin testified that he was astonished at witness Ellis's "comment" regarding the difference between "return on equity" as an accounting principle and "cost of equity" as an economic principle, he did not dispute any of the basic definitions used by witness Ellis to describe the difference between these concepts. Tr. vol. 8, 206; 251-52; vol. 21, 940-43.

This distinction matters in part because any model that purports to estimate the cost of equity based on historical or forecast utility returns on equity will lead regulators astray. Tr. vol. 21, 944-46. Those models—such as witness Morin's Risk Premium Methodology (RPM) relying exclusively on historical utility returns and on authorized returns on equity—"incorporate no information about the actual cost of equity" and "produce invalid results." *Id.* at 945. For any given company, the cost of equity and the return on equity may be the same numerical amount, but they will not necessarily equal each other at any given time.[1]

There is ample evidence that authorized ROEs for regulated electric public utilities have exceeded the cost of capital for decades. As shown below:

- Market-to-book ratios in the proxy group are about 2.0, direct evidence that the allowed ROEs for those companies exceed the cost of capital.
- Since the 1980s, the spread between authorized ROEs and the risk-free rate has widened substantially.
- Authorized ROEs are higher than expected returns from equity investments in the market as a whole when investors should expect lower returns from utility investments.

[1] As witness Ellis explained, one possible source of the conflation between these concepts comes from finance professionals, who "commonly refer to the cost of capital as the expected return (on capital)." Tr. vol. 21, 944.

DEP witness Morin has provided no compelling reason for the Commission to disregard these key indicators that demonstrate the misalignment between authorized ROEs and the cost of equity.

1. *High Market-to-Book ratios for public utilities demonstrate that authorized returns on equity have exceeded the cost of equity capital.*

Given the difference in book value and market value of the utilities in witness Morin's proxy group—as well as for DEP's parent company—it is apparent that expected returns on equity investments (i.e., the cost of capital) are less than currently authorized ROEs for public utilities. At market-to-book ratios near 2.0 (which is the case for the companies in witness Morin's proxy group), investors' expected returns are significantly lower than the returns on book equity. Tr. vol. 21, 950-55. Investors cannot buy securities at book value, but instead at market value. Tr. vol. 8, 266. As witness Morin acknowledged, paying more for a given stream of cash flows necessarily means that expected returns are lower. *Id.* at 262. Thus, the returns on equity for utilities that have a market value that is, on average, twice book value, necessarily indicate that investors' <u>actual</u> return on equity expectations are lower than the authorized return on equity. Tr. vol. 21, 962-63. If the return on book value of equity is 10%, and an investor buys stock in that company at a market to book ratio of 2.0, then the actual return that investor expects on the equity investment is 5%.

As witness Ellis noted, a reasonable rule of thumb equates the market-to-book ratio to the ratio of return on equity to cost of equity, which would imply that the average cost of equity for the proxy group is approximately 5.5%. Tr. vol. 21, 953-54. Put another way, for every dollar of equity that a utility invests when its market-to-book ratio is greater than one, its shareholders receive not just a reasonable return, but additional value beyond the cost of capital. *Id.* at 954. That additional value comes at ratepayer expense.

In his book *New Regulatory Finance*, witness Morin has acknowledged that when the return on equity is equal to the cost of equity, the market-to-book ratio of a utility will approach 1.0:

> In Chapter I, it was suggested that if regulators set the allowed rate of return equal to the cost of capital, the utility's earnings will be just sufficient to cover the claims of the bondholders and shareholders. No wealth transfer between ratepayers and shareholders will occur.
>
> The direct financial consequence of setting the allowed return on equity, *r*, equal to the cost of equity capital, *K*, is that share price is driven toward book value per share, at least in theory under ideal conditions. Intuitively, if r>K, and is expected to remain so, then market price will exceed book value per share since shareholders are obtaining a return in excess of their opportunity cost.

NCJC, *et al.*, Cross Examination Morin Direct Rebuttal Ex. 1 (Official Ex. vol. 9 at 88). Moreover, witness Morin suggested that regulators should set “the allowed return so as to obtain an M/B ratio of at least 1.0…[which] abides by the financial integrity criterion of the *Hope* case and the financial soundness criterion of the *Bluefield* case.” *Id.* at 89.

But witness Morin nevertheless discounts the significance of market-to-book ratios of regulated public utilities far surpassing 1.0. Witness Morin has not justified his claim that regulators should likewise disregard this key metric, which can reveal whether allowed returns on equity have gotten out of sync with investors' actual expected returns. Witness Ellis demonstrated in detail that witness Morin's attempt to explain away the significance of excessive market-to-book ratios lacked substance. Tr. vol. 21, 955-65. For example, witness Morin's attempt to justify excessive market-to-book ratios as being necessary to address inflation without any merit. *Id.* at 957-58. Expected inflation is already reflected in the cost of debt and equity calculations.

To the extent witness Morin would justify market-to-book ratios of about 2.0 for the proxy group as somehow making up for periods when the ratios were below 1.0 does not comport with the historical record. Those ratios have averaged over 1.0 since the 1920s, so regulators could maintain a market-to-book ratio of 1.0 into perpetuity and the average long-run ratio would never drop below 1.0. *Id.* at 958-59. Nor is there any merit to witness Morin's suggestion that utilities could not attract capital without maintaining market-to-book ratios above 1.0. As witness Ellis demonstrated, investors buy shares of companies spanning a wide range of market-to-book ratios, including those below 1.0, as was the case for the utilities sector from the early 1970s to mid-1980s, a time when utilities were nevertheless able to attract equity capital. *Id.* at 952, 960.

Notably, when public utilities were experiencing market-to-book ratios below 1.0 in the 1970s and early 1980s, Lawrence Kolbe of Brattle argued that achieving a market-to-book ratio of 1.0 should be a "guide for regulators," because in that instance, the allowed rate of return will be equal to the cost of capital. *Id.* at 964 (quoting A. Lawrence Kolbe, James A. Read, Jr., and George R. Hall, *The*

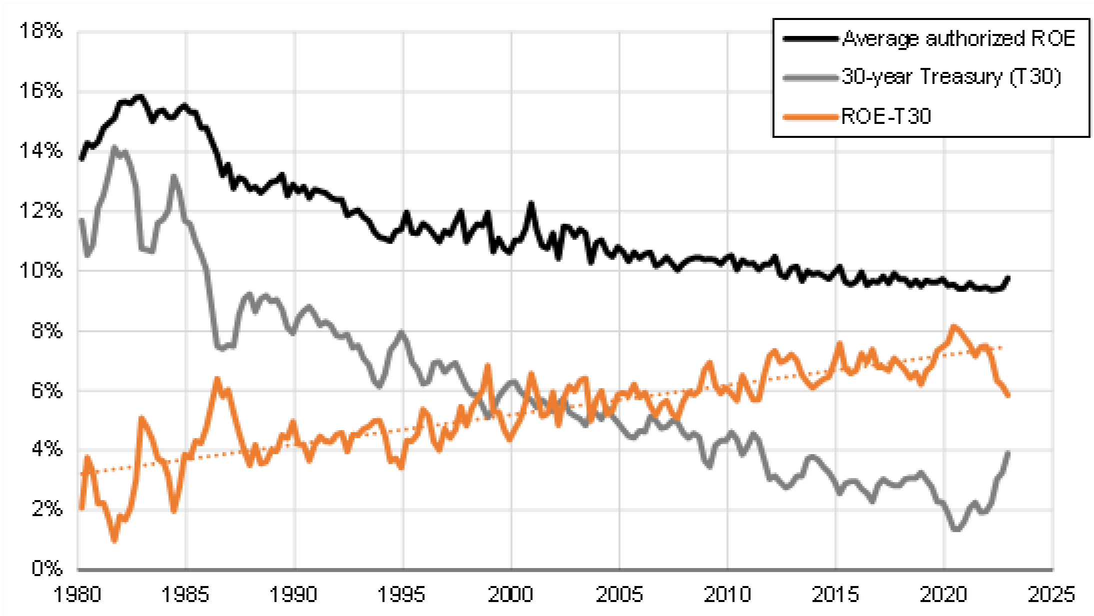
Cost of Capital: Estimating the Rate of Return for Public Utilities, Charles River Associates, Inc. at 25 (1984)).

Alfred Kahn observed this same problem from a prior era when market prices of public utilities had appreciated to one and half and two times their book value (from the late 1940s to 1965), which he explained was caused by permitting utilities to earn returns that were considerably more that their actual cost of capital. Tr. vol. 21, 951 (quoting Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, Mass. Inst. Tech. at 48 (fn. 69), 50 (1970)). Sound economic principles would support the Commission in considering market-to-book ratios when establishing the lowest possible ROE that would comport with constitutional and legal standards.

2. Widening spread between the Risk-Free Rate and Authorized ROEs.

The widening spread between the risk-free rate (as represented by the 30-year U.S. Treasury rate) and commission-authorized ROEs is further evidence that allowed ROEs exceed the actual cost of equity. Both DEP witness Morin and NCJC, *et al.* witness Ellis provided a graphic representation of this widening spread (represented by the orange line in Ellis Figure 6, growing from about 2% in 1980 to 8% in 2020). Tr. vol. 21, 968, Figure 6; Morin Ex. RAM-9 (Official Ex. vol. 9 at 475).

Ellis Figure 6. Quarterly average authorized ROE and 30-year Treasury rate



Witness Ellis demonstrated that in addition to the national trend of authorized ROEs exceeding the cost of capital, DEP's authorized ROEs have exceeded the national average for authorized ROEs, despite DEP maintaining a vertically integrated business model that has a lower risk profile than many of its peers. Tr. vol. 21, 969-70.

Witness Morin does not attempt to explain the widening spread between the risk-free rate and authorized ROEs since 1980, but instead takes them as "presumably" reflective of "market-based methodologies" and the "actions of objective unbiased investors in a competitive marketplace." Tr. vol. 8, 79. But he does not explain in what possible way commission-authorized ROEs are the result of actions of investors in a competitive marketplace. Witness Ellis, in contrast, cited the scholarship of researchers at Carnegie Mellon, who investigated this widening spread between the risk-free rate and authorized ROEs and could not find a satisfactory economic explanation for the widening divergence. They concluded that the result is "excess returns [that] translate into tangible profits for utility firms." Tr. vol. 21, 968 (quoting David C. Rode & Paul S. Fishchbeck, *Regulated equity returns: A puzzle*, 133 Energy Pol'y 1, 16 (2019)).

Any model for estimating the cost of equity that relies on previously authorized ROEs will have the effect of locking in this widening spread and should be disregarded. Tr. vol. 8, 27. Witness Ellis noted that relying on previously authorized ROEs to estimate the actual cost of equity is akin to basing a diet recommendation solely on what a person has been eating rather than on what foods they should eat to be healthy. Tr. vol. 21, 969.

3. Authorized ROEs for regulated public utilities are higher than independent capital market assumptions about returns on U.S. equity markets generally.

Authorized ROEs for the regulated public utilities in the proxy group are higher than expected returns provided by capital market assumption reports from independent investment firms for equity markets as a whole. Tr. vol. 16, 280, Table CCW-10; tr. vol. 21, 383 (DoD/FEA witness Reno noting that the Federal Reserve Bank of Philadelphia recently reported the average forecast of expected returns on the S&P 500 of 7.5% over the next decade); 622-24 (CUCA witness O'Donnell summarizing the future returns anticipated by investment firms such as Blackrock, Fidelity, JP Morgan, and Morningstar for the overall market, which are all lower than Morin's utility cost of equity and risk premium results); 946-49 (witness Ellis's review of Capital Market Assumption reports). CUCA witness O'Donnell noted that independent market forecasts are substantially lower than the 11% return that witness Morin's CAPM results would suggest, showing that Morin's "results are simply unreliable." Tr. vol. 21, 636.

As witness Morin acknowledged, to the extent those independent capital market assumptions are reflective of actual investor expectations, they would contradict any authorized ROE higher than those expected returns from the market generally. Tr. vol. 8, 157-58. The reason for this is straightforward: utility stocks have a lower risk profile than the equity market, given their consistent cash flow, protection from competition, dividends with above-average yields, and steady earnings, even during recessions. *Id.* at 158; tr. vol. 21, 357-59, 372, 947. In other words, if it is true that investors are expecting returns that range from 4.7% to 8.2% from the equity markets, as summarized by Public Staff witness Walters, then the cost of capital from the point of view of investor expectations for a public utility like DEP must fall below those average ranges. Tr. vol. 8, 158, 184; tr. vol. 16, 280; tr. vol. 21, 622-24; 948-49.

As witness Ellis demonstrated, none of the capital market assumption reports out of the dozens that he reviewed indicate that investors are expecting returns greater than about 8% (with an average of about 6%) over the next 10 years from the market as a whole. Tr. vol. 21, 949, Figure 3. As Morin acknowledged, investor return on equity expectations for a public utility like DEP are necessarily below that range.

In rebuttal testimony, witness Morin's principal reason for why the Commission should disregard capital market assumption reports is that such market forecasts include disclaimers. Tr. vol. 8, 158, 279 (quoting from the fine print of the final page of the 2023 Long-Term Capital Market Assumptions report from JP Morgan Chase). But if witness Morin took this argument seriously, he could not in good faith rely on Value Line's growth forecasts or Blue Chip Economic Indicators forecast of yields on 30-year U.S. Treasury Bonds. Tr. vol. 8, 56-59. Both Blue Chip Economic Indicators and Value Line have the same sorts of disclaimers in their reports, as would any reasonable financial publication that presents a forecast of uncertain future market or economic conditions. *Id.* at 276-82; NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 6 and 7 (Official Ex. vol. 9 at 136-45).

Witness Morin has no principled reason for why the Commission should disregard independent Capital Market Assumption reports, which support the conclusion that allowed returns on equity set by public utility commissions are higher than justified in comparison to reasonable investors' expected returns. This lack of a principled reason to disregard the findings of Capital Market Assumption Reports from institutional investors and professional analysts is not surprising, given that witness Morin otherwise justifies relying on analysts' forecasts of long-term growth rates for his DCF model:

> Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available and are representative of the consensus view of investors and are thus consistent with the use of current market prices. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts

> influence investor growth expectations and provide a sound basis for estimating the cost of equity.

Tr. vol. 8, 46. These same reasons support the Commission's consideration of Capital Market Assumption reports when estimating the returns investors expect under current market conditions for the markets as a whole, which will be higher than investors' expected returns for utility investments.

Morningstar, an investment advisor firm, determined that the cost of equity for Duke Energy Corporation, the parent company of DEP, is 7.5% as part of its discounted cash flow analysis. Public Staff Cross Examination Morin Direct Rebuttal Ex. 7, at 4 (Official Ex. vol. 9 at 261). Morningstar notes that a 7.5% cost of equity for Duke Energy "is lower than the 9% rate of return we expect investors will demand for a diversified equity portfolio, reflecting Duke's lower sensitivity to the economic cycle and lower degree of operating leverage." *Id.* This kind of outside view of investor expectations provides a more realistic assessment of the actual cost of equity than the results of any of witness Morin's analyses and should carry significant weight with the Commission. Morningstar, like the Capital Market Assumption reports noted above, is unbiased when it comes to the contested issue of authorized ROE in this case; Morningstar is just trying to find an accurate estimate of the cost of equity so that it can provide informed investment advice to its clients.

To the extent the authorized ROE is higher than required to fairly compensate investors "commensurate with returns on investments in other enterprises having corresponding risks," customers will pay more to DEP on their utility bills than is justified. *Hope*, 320 U.S. at 603.

C. DEP Did Not Meet Its Burden of Proof to Establish an Authorized ROE of 10.4%.

Any estimate of the cost of equity that is used to set the authorized return on equity will be informed by judgment calls about the appropriate inputs and assumptions used to make that calculation. At every step, witness Morin's assumptions and choices for model inputs had the effect of biasing his results upwards. Moreover, his history of inflated recommended ROEs, failure to document key changes made to his methodology between direct and supplemental testimony, and inconsistent approach to modeling are all independent reasons why this Commission should disregard his ROE recommendation.

1. Witness Morin has a history of recommending ROEs for electric public utilities before state commissions that are, on average, 100 basis points higher than those approved by those commissions.

A straightforward reason for this Commission to reject witness Morin's proposed ROE of 10.4% is that there is no evidence that any public utility commission has ever adopted his recommended ROE. DEP was asked in discovery to provide a summary of relevant information from witness Morin's prior testimony relating to recommended ROEs before regulatory commissions, including his recommended ROE and capital structure, the ROE and capital structure ultimately set by the commission, and whether those issues were resolved by settlement or litigation. NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 2 (Official Ex. vol. 9 at 94-95); tr. vol. 8, 255-56. DEP declined to provide that information. Instead, DEP directed the Public Staff to find that information on its own based on the cases listed on Morin RAM Ex. 1 and from databases such as Regulatory Research Associates (a part of S&P Global Market Intelligence). *Id.*

A review of state public utility commission rate case decisions for electric public utilities in which witness Morin made the ROE recommendation for the utility since the early 1980s reveals that his recommendations are always higher than the ultimate decision reached by the Commission, regardless of whether the cases were fully litigated or settled. NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 3 (Official Ex. vol. 9 at 94-103); tr. vol. 8, 261. The one apparent exception—in which the recommended ROE is listed as being the same as the authorized ROE—is from a Hawaii Electric case (Docket 04-0113). Tr. vol. 8, 258-60. But the order in that case[2] reveals that in this instance, Regulatory Research Associates put the wrong number in the recommended ROE column. Witness Morin initially recommended a ROE of 11.5%, which was reduced to 11% in his rebuttal testimony, before the Hawaii commission ultimately approved the 10.7% ROE agreed to in settlement. *Id*. DEP offered no evidence to rebut this showing that witness Morin's inflated recommended ROEs have never been accepted by state public utility commissions.

In every case before a state public utility commission in which Morin provided the electric utility's proposed ROE, commissions have approved ROEs that are, on average, 100 basis points lower than his recommendation. Witness Morin agreed that in those cases, his testimony would have included the assertion

[2] The Commission took judicial notice of the decision of Public Utilities Commission of Hawaii, *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of Rate Increases and Revised Rate Schedules and Rules*, Docket No. 04-0113, Decision and Order No. 24171 at 73-78 (May 1, 2008). Tr. vol. 8, 260.

that his recommended ROE was the minimum amount required to comply with constitutional standards. Tr. vol. 8, 261. And witness Morin had no evidence that the resulting commission-authorized ROEs impaired the ability of those utilities to access the capital markets or adversely affected the financial integrity of those utilities in any way. *Id*. But it is an inescapable fact of basic arithmetic that those commission approved ROEs saved ratepayers substantial sums of money in comparison with witness Morin's recommendations.

As set forth above in Section IV.B., there is considerable evidence that even those commission decisions, which are on average 100 basis points lower than witness Morin's recommended returns on equity, are higher than the actual costs of capital for regulated public utilities since the 1990s. For this reason, simply skimming 100 basis points off the top of witness Morin's recommended 10.4% would not be sufficient to comport with the legal requirement to set the lowest ROE possible consistent with constitutional mandates.

The independent cost of equity estimates provided by expert witnesses for the Public Staff, CUCA, and DoD/FEA, were similarly 115 to 140 basis points lower than witness Morin's recommendation, in the event the Commission approved a multiyear rate plan. Tr. vol. 8, 134. Witness Ellis optimized his recommended ROE, which is 440 basis points lower than witness Morin's recommendation, with a 58% equity ratio that would allow DEP to maintain the FFO-to-debt ratios needed to maintain its current bond rating. Tr vol 21, 1071-72. Witness Ellis's recommendation would save customers $370 million per year (based on DEP's initial requested revenue requirement). *Id*. at 1073.

2. Witness Morin's decision to only update his recommended ROE when that number went up undermines his credibility; the Commission should reject DEP's argument to selectively disregard only portions of Morin's testimony.

Witness Morin testified in response to cross examination and questions from Commissioners that his recommended ROE is now 10.2%, but that he had no intention of supplementing his testimony with an updated recommendation to lower his recommended ROE. Tr. vol. 8, 324; tr. vol. 9, 47-48, 63-64. Given witness Morin's decision to submit supplemental testimony when he determined that the ROE could be higher than his initial recommendation, his decision to not affirmatively supplement his recommendation when the number went down is suspect and should undermine his overall credibility as an independent expert with this Commission.

In a late-filed exhibit, DEP attempted to distance itself from its expert's revised opinion on a lower recommended ROE. DEP Late-Filed Exhibit 9 (May 25, 2023). DEP's argument should be dismissed by the Commission. DEP should not be allowed to argue that considering Morin's revised ROE recommendation is somehow inconsistent with the Commission's scheduling order. It was DEP, after all, that insisted that the Commission consider the Moody's May 2023 Credit Report, which also post-dates March 31. Tr. vol. 22, 214; DEP Redirect Newlin Rebuttal Ex. 1. There is simply no principled basis for considering a Moody's Credit Report from after March 31 to influence the Commission's ROE decision while at the same time disregarding witness Morin's most recent ROE recommendation. DEP cannot have it both ways.

DEP's argument that witness Morin's responses to questions on cross-examination and from Commissioners on his revised ROE recommendation should be discounted as "speculation" also lacks any support. Tr. vol. 8, 324; tr. vol. 9, 48, 51, 63-64. At no point did witness Morin caveat or qualify his testimony on his revised recommendation of a 10.2% ROE. If witness Morin's responses relating to his revised recommendation should be disregarded as speculation, then there would be no way to distinguish when his responses to any Commissioner questions or cross-examination should likewise be disregarded as mere speculation. Morin gave his revised ROE recommendation under oath from the witness stand. DEP has offered no reason to selectively disregard his opinion. If his revised ROE recommendation should be disregarded as speculation, then none of his other testimony should be given any weight at all.

Ultimately, witness Morin's ROE recommendation is unjustifiably inflated, at either 10.4% and 10.2%. But DEP has provided no basis for only considering the higher of his two recommendations.

3. *Key inputs and assumptions underlying witness Morin's analysis biased the results of his DCF and CAPM models upwards, the results of his Morin ECAPM and Risk Premium Methods should be disregarded, his position on the effect of risk mitigators was inconsistent, and his flotation adjustment is unwarranted.*

Any model is only as good as the inputs and assumptions that are used to implement that model. Tr. vol. 8, 40. DEP witness Morin made several choices that upwardly biased the results of his DCF and CAPM models (the only two of Morin's models that the Commission should consider when estimating the cost of equity).

Correcting those errors results in a much lower cost of equity estimate that the Commission should use when setting the authorized ROE for DEP.

a. Morin's Constant Growth DCF result is unreliable.

The discounted cash flow (DCF) model is based on a widely used mathematical formula for the value of a stream of cash flows that grows in perpetuity. Tr. vol. 21, 972. The model can be expressed to estimate the cost of equity by adding expected dividend yields plus the expected rate of growth of dividends, earnings, stock price, and book value. Tr. vol. 8, 42-43. The model thus relies on two key variables: dividend yields and growth rates. Errors in either input will distort the results of the model.

i. Morin's Constant Growth DCF result is unreliable because it irrationally assumes analyst's short-term growth projections continue indefinitely, which is economically impossible, and include other sources of upward bias.

Witness Morin's constant growth discounted cash flow analysis (CG DCF) suffers from a fatal flaw: it assumes that "dividends can grow at analysts' estimated EPS growth rates into perpetuity. This assumption is economically impossible and adds substantial upward bias to his results." Tr. vol. 21, 972. Public Staff witness Walters came to a similar conclusion: his "major concern with Dr. Morin's DCF analysis is that his DCF results are heavily impacted by growth rates that cannot be sustained in the long run… ." Tr. vol. 16, 301.

One alternative approach that removes the flawed assumption that short-term analyst growth forecasts can be sustained into perpetuity in the CG DCF model is a multi-stage DCF, which can consider varying growth rates at different time frames, including a terminal growth rate that matches the overall economy.

Witness Ellis and Public Staff witness Walters employed multi-stage DCF models in their analyses. Tr. vol. 16, 257-64; tr. vol. 21, 990-96. Witness Walters's multi-stage DCF model estimated the cost of equity for the proxy group of about 7.9%. Tr. vol. 16, 264. The multi-stage DCF can consider both the short-term growth forecasts as well as terminal growth rates that converge on growth rates in the economy as a whole.

In rebuttal, witness Morin testified that the "Achilles' heel" of the multi-stage DCF is the assumption that "utility growth rates match that of the macroeconomy" and that he is "not aware of any financial literature supporting the notion that the investment community looks to GDP growth over the next several decades when evaluating utility investments." Tr. vol. 8, 147.

But Morin's testimony is contradicted by his own publication, *New Regulatory Finance*. In a section relating to growth in the non-constant DCF model (which includes the multistage DCF model), witness Morin wrote precisely the opposite of what he said in rebuttal: "It is useful to remember that eventually all company growth rates, especially utility service growth rates, converge to a level consistent with the growth rate of the aggregate economy." NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 1 (*New Regulatory Finance* at 308) (Official Ex. vol. 9 at 86). Despite witness Morin's assertion that the multi-stage DCF is "mis[-]specified," he recognized the shortcomings of the constant growth DCF in his book:

> The problem is that from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue into perpetuity. A transition

> must occur between the first stage of growth forecast by analysts for the first five years and the company's long-term sustainable growth rate.

Id. Although Morin claimed to be unaware of *any* financial literature that would support the idea that over the long term, growth rates of utilities would converge to GDP, he himself wrote about that phenomenon, further noting that "it is quite possible that a company's dividends can grow faster than the general economy for five years but it is quite implausible for such growth to continue into perpetuity." *Id.* at 87.

ii. Exclusive reliance on forecast Earnings Per Share for growth rate.

An additional factor that upwardly biased witness Morin's CG DCF result is his reliance on an analyst's estimate of future earnings per share growth rates. Tr. vol. 21, 975; tr. vol. 16, 301 (noting that Value Line's growth rates represent the projections of a single analyst). Witness Morin otherwise notes his belief in seeking out consensus forecasts, but for this key variable in his CG DCF calculation, he relies instead on a single analyst's forecast. Tr. vol. 8, 46. Just as flawed, though, is his sole reliance on analysts' forecasts of earnings per share growth as the sole source of the growth factor in the DCF calculation. As a general matter, analyst estimates are known to be upwardly biased. Tr. vol. 21, 975-76 (citing Marc Goedhart, Rishi Raj, and Abjishek Saxena, *Equity analysts: Still too bullish*, McKinsey Quarterly (Apr. 2010); Stefano Cassella, Benjamin Golez, Huseyin Gulen, and Peter Kelly, *Horizon Bias and the Term Structure of Equity Returns* (Nov. 2021)). A comparison of past forecast dividend per share growth rates of the proxy group to their historical growth rates demonstrates the problem of overly optimistic analysts' forecasts. *Id.* at 988, Figure 12. On average, the forecast rates for the proxy group are approximately 3.5% higher, in both real and nominal terms, than the historical average.

Witness O'Donnell similarly raised concerns about overreliance on analysts' forecasts, citing academic and financial literature that demonstrate that analysts' forecasts are "poor indicators of investor expectations" and tend to be overly optimistic. Tr. vol. 21, 629-32.

Witness Morin relies solely on analyst's forecasts of earnings per share (EPS) as a stand-in for dividend growth rates in the CG DCF model. Historical and forecast data, however, demonstrate that earnings per share growth is not representative of dividends per share growth over even the short (3-5 year) time horizon of analysts' EPS forecasts. Tr. vol. 21, 979. Witness Ellis provided compelling empirical evidence that EPS growth rates are not a suitable proxy for DPS growth rates. Both historical EPS and forecast EPS tend to be higher than DPS growth rates, another source of upward bias in Morin's DCF model. Because earnings tend to be more volatile than dividends per share, with higher earnings often following a year of poor performance, for example, relatively short-term EPS forecasts are not a viable input for growth rates in a CG DCF model. *Id.* at 979-85. Using Value Line's other forecasts for share price and dividends per share to calculate expected returns for the proxy group similarly demonstrate that EPS is not a suitable proxy for future dividend growth; using those Value Line forecasts results in an estimated cost of equity of 8%. Tr. vol. 21, 985-87. This proves that even Value Line's analysts do not assume that those EPS growth rates will apply to dividends or that those growth rates can be sustained into perpetuity. *Id.* at 987.

Witnesses Reno and O'Donnell also criticized Morin's exclusive reliance on the single measure of EPS forecasts as the growth rate factor in the DCF model. They in turn mitigated this problem by using data in addition to short-term earnings per share forecasts to inform their estimated growth rates. For example, witness Reno took the average of estimated growth rates from Value Line, Yahoo! Finance, Zacks, and CNN Money. Tr. vol. 21, 375. Witness Reno then developed alternative growth rates by averaging dividend per share and book value per share estimates from Value Line, because investors want assurance that dividend growth can be sustained. *Id.* at 376. Notably, witness Reno testified that if her analysis had relied solely on other analysts' forecast earnings per share as her growth rate, as witness Morin did, her proxy group DCF cost of capital estimates would be about 9.55%, about 40 basis points higher than her results after combining EPS forecasts with dividends per share and book value per share estimates. *Id*. Likewise, CUCA witness O'Donnell used several methods to estimate dividend growth rate in his DCF model. Tr. vol. 21, 608-12. O'Donnell considered historical earnings per share, dividends per share, and book value per share (BPS) growth rates; forecasted EPS, DPS, and BPS growth rates; and the plowback ratio. *Id.* Witness O'Donnell testified that using only forecast EPS for the dividend growth rate in the DCF model would "produce unrealistically high return on equity numbers that cannot be sustained indefinitely." *Id.* at 610.

b. Morin's CAPM results are biased upwards.

In the Capital Asset Pricing Model (CAPM), the cost of equity is derived by adding the risk-free rate to the market risk premium, which is in turn derived by multiplying the stock's beta times the difference between the expected return on the market minus the risk-free rate. Tr. vol. 21, 996-97; vol. 8, 55. Any upward bias on any of these variables will a large impact in the estimated cost of equity calculation.

i. Witness Morin does not support his decision to rely solely on Value Line for his beta estimates, which biases his results upwards

Beta—a key input into the capital asset pricing model—is the measure of how closely a given stock moves in relation to the market as a whole. In the CAPM, the estimated risk-free rate is multiplied by the beta, so any upward bias in the beta will have a large impact in the estimated cost of equity calculation. For the proxy group, witness Morin relied on only one source for betas, Value Line. Value Line uses the so-called Blume adjustment, which is based on research from the 1970s, which observed a general tendency of betas, on average, to regress towards 1.0. Tr. vol. 21, 1019. But this general trend for stocks does not apply to utility stocks, which have tended to regress to betas of 0.50 to 0.60 since the 1950s. *Id.* at 1019-20. Applying this adjustment to utility stocks has the effect of artificially increasing their betas one-third of the way towards 1.0 and has a large influence on biasing Morin's results upwards.

At the hearing, witness Morin was confronted with stark evidence that utility stocks are not moving with the market. Tr vol. 8, 249-50; DoD/FEA Cross

Examination Morin Direct Rebuttal Ex. 3 (Official Ex. Vol. 9 at 56). When shown a chart from Fidelity that demonstrated that the utilities sector was overperforming the broader market in 2022, witness Morin's response was that in the first quarter of 2023, the results showed the opposite, with utilities now underperforming the broader market. Tr. vol. 8, 249-50. In other words, recent market data undercuts witness Morin's assertion that utility betas are moving in sync with the market as would be expected if utility betas were actually approaching 1.0.

Witness Morin's principal support for his sole reliance on Value Line betas for his CAPM (as well as for the Morin ECAPM) analysis is an article from 1983, based on a review of betas largely from the 1970s. Tr. vol. 8, 214 (citing Harrington, *"Whose Beta is Best?"*, FINANCIAL ANALYSTS' JOURNAL, July-August 1983, Vol. 39); NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 8 (Official Ex. Vol. 9 at 146-54). Yet in that article, Harrington concluded that "there is no single best method of estimating a beta." *Id.* at 149. More importantly, for the utility sector, Harrington concluded that "beta forecasts . . . overestimated the actual betas." *Id.* at 151. The results from the utility sample indicated that Value Line betas had an error of 0.28, a sizeable error when the mean beta forecast for the sector was 0.7241. In other words, compensating for this error would bring Value Line's betas for the time in Harrington's study to 0.44.

In addition, Harrington concluded that Value Line's errors, which consistently overestimated actual betas, means that OLS betas (or raw betas) are superior for the utility sample. *Id.* When confronted with Harrington's conclusion that Value Line betas result in sizeable errors and those errors are always in the direction of inflating betas, witness Morin ignored Harrington's conclusion and instead relied solely on one metric, the mean square error of Value Line betas. *Id*. at 152; tr. vol. 8, 290-95. Witness Morin acknowledged that the direction of error is a relevant consideration, and it is significant if one particular method for estimating betas, such as Value Line's, consistently results in an overestimate. Tr. vol. 8, 295.

When confronted with an academic analysis that found no basis for the use of the Blume adjustment for utility stocks over a several decade period, witness Morin dismissed the results of that study because the data was from 2013 and earlier. Tr. vol. 8, 297; NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 9 (Official Ex. vol. 9 at 155-63). Morin's argument for ignoring Professors Michelfelder and Theodossiou's research from "2013 and prior to that" as "way, way, way back" is impossible to square with his reliance on Professor Harrington's research based on data from the 1970s to justify his reliance on Value Line betas. Witness Morin's ultimate response, that utility betas are approaching 0.90 now, is based on Blume adjusted betas, not raw betas, which remain substantially below 1.0. Tr. vol 8, 297; tr. vol. 21, 1009. Moreover, even if utility betas have been trending upward, which is only true for sources that use the Blume adjustment, witness Morin provided no support for further adjusting those betas towards 1.0.

There are a number of equally valid and commonly used methods for estimating betas. The resulting betas can vary significantly depending on seemingly random differences in methodology, including the day of the week chosen to calculate weekly returns. Tr. vol. 21, 1017. It is precisely for this reason that it is better to rely on a range of estimated betas that use different methodologies as opposed to relying on a single source, as witness Morin does. This is particularly problematic when that one source, Value Line, uses a Blume adjustment that artificially moves all betas one-third of the way towards 1.0 and produces results for utility stocks that are the highest of all the most commonly used methods. The supposed upward trend in utility betas that witness Morin cites only appears in sources that use a methodology like Value Line's. Other commonly used sources, such as Yahoo! Finance, S&P Global Market Intelligence, and Zacks do not show any such upward trend. Tr. vol. 21, 1008-09; *see also* NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 11 (excerpt from Morin's *New Regulatory Finance* that lists sources of betas other than just Value Line without denigrating those sources, including Yahoo! Finance and S&P Global Intelligence). The Commission should not rely on any estimated cost of equity calculation that relies solely on Value Line betas.

ii. Morin's unexplained decision to rely solely on forecasts from Blue Chip Economic Indicators for the risk-free rate biased his CAPM results upwards.

Establishing an accurate risk-free rate is a key variable in the Capital Asset Pricing Model (CAPM). The risk-free rate is added to the product of the company's estimated beta times the market risk premium to derive the estimated cost of equity. Reliance on any assumption that artificially increases the risk-free rate will have a direct effect on the result of the analysis, increasing the estimated cost of equity. Witness Morin's unexplained changes to the risk-free rate between his direct and supplemental testimony significantly inflated his final CAPM result. As explained in more detail below, witness Morin's decision to rely exclusively on the Blue Chip Economic Indicators forecasted 10-year Treasury rate with an unjustified 0.5% additional upward adjustment was unreasonable and his resulting CAPM results should be disregarded.

Over the course of ten pages in his pre-filed direct testimony, witness Morin described in detail the various sources and methods that he employed to derive a risk-free rate of 3.7%. Tr. vol. 8, 55-64. As just one part of one step of that analysis, he relied on the Blue Chip Economic Indicators forecast yields of 30-year U.S. Treasury bonds as one of eight sources for his estimate of future bond yields. *Id.* at 59. He then averaged the forecast yields from those various sources with a normalized risk-free rate of 3.3% to derive his initial estimate of 3.7%. *Id.* at 64.

In his supplemental testimony, in stark contrast, witness Morin instead posited that the risk-free rate was 4.3% without explaining any change in his methodology. Tr. vol. 8, 130-31; tr. vol 9, 65; tr. vol 21, 382 (DoD/FEA witness Reno noting that this change was made without explanation). Witness Morin's only explanation for the change in his supplemental testimony is that interest rates increased and thus, "the long-term bond yield forecast is 4.3% versus 3.7%." Tr. vol. 8, 130. In his supplemental testimony, he did not explain that he also had abandoned his prior method of averaging a forecast U.S. Treasury bond yield with a normalized risk-free rate. This change had the effect of substantially inflating this key variable in his CAPM calculations, and thus, increasing his recommended ROE.

Witness Morin did not explain that he decided to rely exclusively on only one forecast, from Blue Chip Economic Indicators (BCEI), to establish his supplemental risk-free rate. Tr. vol. 9, 65; vol. 21, 998-99. There are several problems with witness Morin's approach, which upwardly biased his results. First, it is not logically consistent to use forecast rates for the CAPM model. *See* tr. vol. 21, 997-98. Second, BCEI has consistently overestimated U.S. Treasury yields for decades, making them an unreliable source for such a key input for cost-of-equity calculations. Tr. vol. 21, 999-1007. Current market rates are better predictors of future rates than any economic analysts' forecasts, as witness Morin himself acknowledged in his recent book: "the bond market is very efficient in that it is difficult to consistently forecast interest rates with greater accuracy than a no-change [from the current interest rate] model." Tr. vol. 21, 998 (quoting *New Regulatory Finance*, at 172).

Witness Morin does not explain how investors can be relying on the BCEI forecasts on the one hand, which have a long track record of overestimating future interest rates, while market participants are at the same time buying bonds at current yields. Any purchase at today's yields indicates that investors do not expect the yield to go up (given the inverse relationship between a bond's value and its yield, buying today—if one expects the yield to increase—would mean the buyer expects a loss on their investment). Tr. vol. 21, 1004-05. Finally, witness Morin does not justify his 0.5% upward adjustment to the BCEI 10-year U.S. Treasury yield to make it more comparable to a 30-year bond. *Id.* at 1005-06. The more recent average spread between the yields of 30-year and 10-year Treasuries is closer to 0.1% than 0.5%. *Id*. at 1006-07.

When asked about his failure to explain these significant changes in his approach between his direct and supplemental testimony, witness Morin said that he went with the BCEI forecast "[i]n order to be consistent with the other witnesses that use [BCEI]." Tr. vol. 9, 66. But this explanation makes no sense. Witness Morin's supplemental testimony was filed on February 13, about six weeks before the testimony of the Public Staff or other intervenors. Tr. vol. 8, 18. Moreover, in addition to witness Ellis, most of the other ROE witnesses specifically criticized Morin's reliance on interest rate forecasts like those put out by BCEI and instead advocated for reliance on current market rates as superior inputs to their calculations[3]:

- CUCA witness O'Donnell: "Interest rates are in constant flux as the market adjusts to shifting expectations of future inflation, rate changes, and other economic forecasts—which shows that current interest rates reflect investors' expectations of future events." Tr. vol. 21, 634. Witness O'Donnell then summarized recent research demonstrating that economists' forecasts of future bond yields are highly inaccurate and tend to overestimate future yields. *Id.* at 634-36.
- DoD/FEA witness Reno: "[Morin]'s reliance on forecasted interest rates...inflate expectations of long-term interest rates that are not sustainable. (By contrast, I rely on the most current market data. . . which produces results that are more up to date and accurate)." *Id.* at 348.

[3] Public Staff witness Walters similarly criticized Morin's reliance on long-term bond yield forecasts and advocated for relying on shorter term projections, which would result in a risk-free rate of 3.7%. Tr. vol. 16, 305.

Consistent with witnesses O'Donnell and Reno, witness Ellis documented the close relationship between current market rates and future interest rates, showing that they are indeed a more reliable predictor of future rates. Tr. vol. 21,1003-04. Just as importantly, using current rates as a proxy for future rates has the virtue of being unbiased. They are equally likely to be too low as too high, unlike BCEI, which consistently overestimates future rates. *Id.*

Witness Morin's only explanation for his switch to solely relying on BCEI forecasts (with an upward adjustment) to set the risk-free rate does not fit the record and his resulting calculations should be disregarded.

iii. Reliance on arithmetic means.

Another assumption made by witness Morin that upwardly biases the results of his CAPM models is the use of arithmetic average returns to derive his historical market risk premium. Tr. vol. 8, 67-70. In rebuttal, witness Morin went so far as to say that there "is no theoretical or empirical justification for the use of geometric mean rates of return in estimating the cost of capital." Tr. vol. 8, 210. But witness Ellis provided both empirical and theoretical support for using geometric averages in his direct, including extensive quotes from leading scholars of valuation that support using geometric average returns when considering long-term cost of capital calculations. Tr. vol. 21, 1024-27 (citing Tim Koller, et al., *Valuation*, McKinsey & Co. at 852-853 (6th ed. 2015) and Professor Aswath Damodaran). And witness Morin agrees that the goal of the CAPM is to consider the long-term cost of equity. Tr. vol. 8, 57 (testifying that the "expected common stock return is based on very long-term cash flows").

At the hearing, witness Morin acknowledged that he was very familiar with the scholarship of Professor Aswath Damodaran of the Stern School of Business at New York University. Tr. vol. 8, 298. In his recent Equity Risk Premium report, Professor Damodaran explained the theoretical and empirical basis for relying on geometric returns when considering long periods of time, noting that arithmetic returns will "overstate the premium." NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 10 at 36-37, (Official Ex. vol. 9 at 164, 175-76). Geometric average returns are especially important for stock returns, which are negatively correlated over time. *Id.* at 36-37, n. 73. In other words, good years in the markets are typically followed by bad years, and vice versa. Tr. vol. 21, 1025-56.

For any analysis that covers a long-time horizon, such as the historical risk premium, the geometric average return will provide a more accurate result. Witness Morin apparently agrees, noting in his direct that "geometric average return should be used for measuring historical returns that are compounded over multiple time periods." Tr. vol. 8, 69-70. His historical risk premium purports to do just that—consider historical returns over multiple time periods. While witness Morin can say that "nobody" agrees with using geometric means for measuring long-term historical market returns for the CAPM risk premium, his saying so does not make it true. Tr. vol. 8, 302.

c. Morin ECAPM should be completely disregarded.

The so-called Morin ECAPM is not used outside of utility regulatory proceedings. Tr. vol. 21, 1039. The research justifying its use generally is out of date, does not fit more recent trends, and does not fit public utilities' stocks at all.

Id. at 1038-44. "Despite its name, the empirical data do not support the ECAPM's modifications to the traditional CAPM for use in estimating the cost of equity" for utilities. *Id.* at 1044. When the analysis cited as a reason for using the ECAPM is revised to reflect the parameters of a utility cost of equity proceeding, the purported flatness relative to a short-term rate disappears. *Id.* In his rebuttal testimony, Morin did not address any of witness Ellis's substantive critiques that demonstrate the unsuitability of the Morin ECAPM. Moreover, witness Morin's justification for using Morin ECAPM—that it is required to adjust returns from low-beta securities—flies in the face of his assertion that utility betas are at 0.9. Tr. vol. 9, 32. That testimony contradicts his assertion in his direct that "regulated utilities" are "low-beta stocks." Tr. vol. 8, 74-75. In other words, witness Morin's claim that utility betas are approaching 1.0 undercuts his principal justification for using ECAPM in the first place, which would only be relevant, under Morin's theory, for low beta securities. Tr. vol. 8, 217. Morin ECAPM results should be disregarded completely.

d. Morin's Risk Premium results should be disregarded.

As with the Morin ECAPM, the Historical and Allowed Risk Premium Models (RPM) are not commonly used in finance and suffer from invalidating flaws. Tr. vol. 21, 971. Both of these models "confuse the cost of equity and the return on equity." *Id*. at 1045. The RPM models are based on either historical or allowed returns, neither of which convey any information about investors' expected returns on equity. The Historical RPM is based on historical stock returns, and thus, would repeat the equity premium puzzle (a period in which stock returns exceeded reasonable investor expectations). *Id*. The Allowed RPM is based on past regulatory ROE decisions, which, as explained above, are in a decades long period of overearnings from authorized ROEs that have exceeded the cost of capital. *Id*. at 1046.

The DC Circuit Court of Appeals recently reversed a FERC decision that disregarded, without explanation, FERC's previous rejection of RPM, finding that the RPM "defies general financial logic," is not relied upon by investors, is less accurate than Discounted Cash Flow models, is largely redundant with Capital Asset Pricing Models, and presents "particularly direct and acute" circularity problems because it uses past-allowed returns to set new ones. Tr. vol. 8, 273-75; NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 5 at 27 (Official Ex vol. 9 at 131) (internal quotation marks omitted). The results of witness Morin's RPM analysis should be disregarded for these same reasons.

e. Inconsistent testimony on effect of risk mitigators.

In rebuttal testimony and during cross-examination, witness Morin was adamant that North Carolina's new PBR framework, which consists of PIMs, multiyear rate plans, and residential decoupling, did not appreciably reduce risk to DEP in a way that should affect the allowed ROE. Tr. vol. 8,135-37, 231, 241.

But in response to Commissioner questions, witness Morin took a different tack. First, when asked how the presence of multiple risk mitigators, such as those afforded DEP by HB 951, would affect his recommendation, he says that he would recommend setting the ROE in the lower part of his range. Tr. vol. 9, 44. But that is not what he did here, despite North Carolina having a full suite of risk mitigators for electric public utilities like DEP. Instead, his recommendation was at the midpoint of his range, with no reference to any of the risk mitigators available to DEP. Tr. vol. 8, 26, 88. Similarly, despite having previously testified that he could not quantify the effect of risk mitigators on ROE, during questions from Commissioners, witness Morin said that the presence of multiple risk mitigators could have a downwards 25 basis point effect on the ROE whereas the presence of just one (in a context where utilities in the proxy group generally have more than one) would be about 10 basis points. Tr. vol. 9, 55-56. The 25-basis point reduction in light of HB 951's MYRP and residential decoupling constructs is in line with the recommendation of witnesses O'Donnell and Walters, which Morin had previously said should be disregarded. Tr. vol. 8, 134-37.

f. Flotation adjustment is unwarranted and not allowed under these circumstances.

The flotation cost adjustment proposed by witness Morin is unwarranted and not allowed under North Carolina law. The Commission cannot include a flotation adjustment in a general rate case based on an historic test year when the Company did not issue any stock and has no plans to issue stock during the MYRP (and thus, has incurred and has no plans to incur actual flotation costs). *State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n*, 322 N.C. 689, 700, 370 S.E.2d 567, 574 (1988) ("Since no evidence was introduced that Duke intends to issue new stock for the next three or four years, and because there was no evidence regarding the probable cost of a prospective issuance, we question whether the record supports any financing cost adjustment").

In addition, as witness Ellis demonstrated, Morin's flotation cost adjustment is based on flawed assumptions and ignores the reality that utilities stocks generally, and DEP's parent company in particular, are trading well in excess of market-to-book ratios of 1.0. Actual flotation costs would be much smaller for the proxy group than Morin's model suggests and are overwhelmed by the imprecision of any model that would be used to estimate the cost of equity. Tr. vol. 21, 1049-54.

D. Witness Ellis, Relying on Sound Finance Principles, Calculated a More Accurate Estimate of the Cost of Equity for Public Utilities and Established an Appropriate ROE for Commission Consideration.

As set forth above, NCJC, *et al*. witness Mark Ellis's testimony demonstrated that authorized ROEs for public utilities exceed the actual cost of capital and identified the faulty inputs and assumptions that upwardly biased witness Morin's estimates for DEP's ROE. In addition, using inputs and assumptions that better reflect reality, witness Ellis provided an independent estimate of DEP's actual cost of equity using a multi-stage discounted cash flow (MS DCF) analysis and capital asset pricing model (CAPM). As explained above, models that are based only on historic or authorized ROEs (such as witness Morin's Risk Premium methodology) provide no information about the cost of equity and thus, were not conducted by witness Ellis. In addition, witness Ellis considered the relationship between ROE and capital structure to arrive at a recommendation that would preserve the funds-for-operations (FFO) to debt ratio that DEP would need to maintain its current credit rating.

Witness Ellis demonstrated that a cost-based ROE of 6% with a modified capital structure would save DEP's customers $370 million per year (from DEP's original proposed revenue requirement) while allowing DEP to maintain its current A2 credit rating.

1. *Ellis's use of MS DCF and CAPM, standard tools used in finance to estimate the cost of equity, corrected the flaws in Witness Morin's approach.*

   a. Results of Ellis's Multi-Stage Discount Cash Flow (MS DCF) Model.

To overcome the shortcomings inherent in the constant growth discounted cash flow model, witness Ellis used a multi-stage DCF method, which models different dividend growth rates over different time periods. Tr. vol. 21, 990. Ellis used an initial growth stage of three years, which is the low end of analysts' EPS growth rate forecast horizon, mitigating the known upward bias of analysts' forecasts. *Id.* at 991. In addition, Ellis considered the average of analysts' short-term growth rate forecasts from three different companies (S&P Global Market Intelligence, Yahoo! Finance, and Zacks), drawing on a much larger sample of analysts' forecasts than Morin's single-analyst projection from Value Line. For the terminal stage, witness Ellis used long-term inflation projections for the growth rate in the proxy group, given the observed long-term correlation between utilities' growth rates (as measured by share price, dividend, and book value) and inflation. *Id.* at 993-94. In between the initial and terminal stages, witness Ellis modeled a 10-year transition stage, in which the growth rate is the average of the initial and terminal rates. *Id.* at 990-91.

Using the multi-stage DCF model, the average resulting cost of capital estimation for the proxy group is 6.25%. Ellis also used the multi-stage DCF to estimate the market risk premium in his CAPM analysis, as explained in more detail below.

b. Results of Ellis's the Capital Asset Pricing Model (CAPM).

To correct for witness Morin's flawed inputs to the CAPM, witness Ellis used the following inputs for the capital asset pricing model: (1) an average beta of the proxy group of .54, derived from betas provided by Yahoo! Finance and Zacks, calculated using five years of monthly returns, striking an appropriate balance between current market sentiment and historic average for utilities, which is consistent with the objective of estimating a multiyear cost of equity; (2) an estimated market risk premium, calculated as an average (about 4%) of both the long-term, geometric average historical MRP (4.91%) and a forward looking estimate using the multistage DCF (3.06%); and (3) risk-free rate based on the current 30-year U.S. Treasury rate rather than the forecast rate. The resulting estimated cost of equity capital for the proxy group is 5.8%.

c. The relationship between authorized ROE and capital structure

Allowed return on equity and capital structure should not be considered in isolation from one another. All other factors being equal, a lower equity ratio in a utility's capital structure tends to increase the cost of equity. Tr. vol. 21, 1054. This makes sense given that debt investors have the first priority on returns from the utility's business. *Id*. at 1054-55. As the equity ratio declines, a smaller share of that cash will be available to pay shareholders (i.e., equity owners). *Id.* Given the potential heightened risk of uncertainty, it will result in a higher cost of equity. *Id.* At the same time, given that the cost of equity is higher than the cost of debt, a higher equity ratio will increase customer costs without any adjustment to the authorized ROE. Tr. vol. 21, 1055-56. The capital structure also has a large role in a company's credit rating, such that a higher equity ratio tends to improve a utility's credit quality. *Id.* at 1056. Similarly, because the authorized ROE has a direct effect on customer rates, and thus, the cash flow to the utility, the ROE has an effect on the funds for operations, a key metric used to determine a company's credit quality. *Id.* at 1057.

As a result of the interplay between capital structure and cost of equity, and because the proxy group average market equity ratio is different than the capital structure proposed by DEP, the proxy group average cost of equity estimate cannot be used to directly estimate DEP's cost of equity. Witness Morin's analysis did not consider the interplay between capital structure and cost of equity at all in his analysis. *Id.* To account for differences in capital structure amongst the proxy group, witness Ellis unlevered the ROEs (in other words, removed any distorting effects of various equity ratios in the cost of equity estimates for the utilities in the proxy group). *Id.* at 1062-65. The average equity ratio for the proxy group is approximately 57%. Unlevering the estimated cost of equity calculations for the proxy group lowered the estimated cost of equity to an average of 5%. *Id.* at 1064.

As witness Ellis demonstrated, considering both the capital structure and ROE in tandem can allow the Commission to optimize an allowed ROE that can maintain the utility's funds-for-operations-to-debt (FFO-to-debt) ratio at a sufficient level to maintain its current credit rating, providing for a lower estimated cost of equity, and providing significant rate relief to DEP's customers. Using information provided by DEP, Ellis optimized the capital structure and the proposed ROE to levels that allow DEP to maintain its current A2 debt rating (with an FFO-to-debt of 22.5%). *Id.* at 1067. This optimized ROE and capital structure would reduce customers' costs by $370 million per year (below DEP's original proposed revenue requirement). *Id.* at 1068-69.

DEP's cost of debt witness Newlin did not make any reference to the FFO-to-debt ratio or any other credit metrics in his direct testimony. *Id.* at 1057. Nor did witness Newlin indicate that he had any disagreement with the underlying FFO-to-debt metrics that Ellis included in his direct testimony. And notably, neither witness Newlin nor Morin provided any forecast FFO-to-debt analysis under DEP's proposed ROE of 10.4% with a 53% to 47% equity to debt ratio. Instead, witness Newlin simply referred to his proposed 53% equity ratio as "optimal" without any support. *Id.*

2. *Witness Morin did not rebut the essential findings of witness Ellis*

Witness Morin's rebuttal did not address the most important points raised in Ellis's testimony. At no point does witness Morin grapple with the empirical evidence that demonstrates that authorized ROEs for utilities are out of sync with reasonable assessments of investors' expectations. At no point did Morin find fault with the results of witness Ellis's MS DCF and CAPM analyses, other than quibbling with his source of betas and two choices for estimating the market risk premium used in the CAPM: (1) the use geometric returns and (2) considering the total return on U.S. Treasury bonds as opposed to the income-only component of those bonds. Instead, Morin resorts to *ad hominin* attacks on Ellis's approach, calling it “non-mainstream, far-fetched, and unorthodox.” But Ellis’s approach more closely follows mainstream finance approaches for estimating the cost of equity than witness Morin’s does. For example, witness Morin offered no examples of the Morin ECAPM or Authorized Risk Premium methods being used outside of utility regulatory proceedings.

In a similar vein, Morin mischaracterizes witness Ellis’s rightful concern about authorized ROEs exceeding the actual cost of capital—which, as Morin acknowledges, would represent a wealth transfer from ratepayers to shareholders—as “virulent,” “unprofessional,” and a “mockery.” Tr. vol. 8, 209-10. But this attack on Ellis’s testimony is completely unwarranted. In the cited passage, Witness Ellis is critiquing a process that utilities around the country have successfully turned to their advantage, resulting in excess profits to utility shareholders. Much of that critique is aimed at the flawed information presented to regulators from people like DEP witness Morin. Tellingly, witness Morin can point to no specific part of Ellis’s testimony as a “mockery” of regulators. Instead, the single example that Morin relied on was a reference to a mathematical model, one which simply highlights the inherent bias in any model that allows for consideration of past results when making new decisions. Tr. vol. 21, 965-66 (referencing the Pólya urn model). And even in that example, witness Ellis noted that the model is an oversimplification, because regulators take into account more information than just past authorized ROEs. *Id.*

a. Morin inaccurately refers to steps Ellis took as "inconsistencies."

In rebuttal, witness Morin purported to identify three inconsistencies in witness Ellis's testimony. In each case, witness Morin was wrong.

First, witness Morin claimed that "Mr. Ellis denounce[d] the use of analysts' growth forecasts in a DCF analysis" but later used analysts growth forecasts in his own analysis. Tr. vol. 8, 205. In other words, witness Morin suggested that witness Ellis denounced a particular approach in his testimony but later employed that same approach. That is false. Witness Ellis denounced the use of *certain* growth forecasts in *certain* DCF analyses, not in all situations. Specifically, he critiqued the use of analysts' *short-term* growth forecasts in the *constant-growth* DCF model, which witness Morin used, as opposed to the *multi-stage* DCF model, which witness Ellis used. Tr. vol. 21, 975-79.

As set forth in Section IV.C.2.a.i. above, it is improper to assume analysts' near-term growth rate forecasts will continue into perpetuity, as was the case in Morin's constant growth DCF model. *Id*. Nevertheless, witness Ellis recognized that, despite their shortcomings, analysts' near-term forecasts are "viewed as the best available estimates of near-term investor expectations." Tr. vol. 21, 992. But because of the well-known biases in those forecasts, "relatively little weight should be placed" on those forecasts when estimating the cost of equity. *Id.* As explained above, a virtue of the multi-stage DCF is that it can appropriately weigh those near-term expectations as just one component of the model, and not project those growth rates continuing forever, as witness Morin unreasonably assumes.

In short, witness Ellis did not denounce the use of analysts' growth rate forecasts in all situations, as witness Morin carelessly suggested. He instead denounced witness Morin's use of 3-to-5-year growth rate forecasts into perpetuity in the constant-growth DCF model. And witness Ellis did not contradict himself by considering those near-term forecasts. He instead explained how they can be used in a way that mitigates their shortcomings.

Second, witness Morin erroneously implied that witness Ellis's use of two different long-term growth rates in two distinct sections of his testimony was inconsistent. Witness Morin wrote, "In his non-constant DCF analysis [at tr. vol. 21, 995], [witness Ellis] relies on a long term growth rate of 1.77% but [at tr. vol. 21, 1036] he uses a long-term growth rate of 3.72%." Tr. vol. 8, 205. The two different growth rates, however, correspond to two different estimates: the long-term growth rate for the utility sector alone—1.77%—and the long-term growth rate for the market as a whole—3.72%. As witness Ellis explained in his testimony, the utility sector historically has grown at the rate of inflation—1.77%—while the economy as a whole has grown at the long-term per-capita nominal GDP growth rate—3.72%. Tr. vol. 21, 993-95, 1036.

Third, witness Morin suggested that witness Ellis's critique of economic forecasts from Blue Chip Economic Indicators (BCEI) was inconsistent with his later use of economic forecasts from "several institutions" to develop his market risk premium (MRP). Tr. vol. 8, 205. But witness Ellis's critique was specific to BCEI, whose forecasts he did *not* use in developing his MRP. Tr. vol. 21, 999-1007, 1034-35.

As explained in Section IV.C.2.b.ii. above, witness Morin relied exclusively on BCEI to develop his supplemental risk-free rate. BCEI, however, has consistently overestimated U.S. Treasury yields for decades, making them an unreliable source for such a key input into cost-of-equity calculations. Tr. vol. 21, 999-1007. In developing his MRP, witness Ellis used forecasts for per-capita GDP growth, not forecasts of U.S. Treasury yields, and did not use forecasts from *BCEI* but from three government agencies: the Congressional Budget Office (CBO), the Energy Information Administration (EIA), and the Social Security Administration (SSA). Tr. vol. 21, 1034-35.

In sum, the three "inconsistencies" that witness Morin purported to identify in witness Ellis's testimony were not in fact inconsistencies. On the contrary, witness Morin's failure to understand these basic aspects of witness Ellis's testimony casts further doubt on the credibility of his recommended ROE.

b. Did not address failure of DEP to consider cap structure in tandem with ROE

One of witness Morin's most confounding criticisms of witness Ellis's testimony is his assertion that Ellis failed to "adjust his recommended ROE to reflect" the difference between his recommended capital structure and the average capital structure of the proxy group. Tr. vol. 8, 218. This critique is hard to comprehend because witness Morin never documents or considers the capital structure of the utilities in his proxy group in his testimony. In contrast, witness Ellis documented the current market capital structure of the proxy group, based on data from S&P Global Market Intelligence, and found that the average equity ratio for the group is 57.4%, which happens to be close to the equity ratio Ellis recommends for DEP. Tr. vol. 21, 1063-64. Moreover, witness Ellis documented the potential distorting effects of differing capital structures on the proxy group and analyzed the proxy group utilities' estimated cost of equity without that distorting effect (the unlevering calculation described above). Witness Morin, in contrast, did not consider the large difference in capital structures amongst the proxy group utilities in his analysis at all.

Witness Morin's criticism on this point would make sense as applied to Morin's own deficient analysis. But it simply makes no sense when directed at witness Ellis's work. Witness Ellis's recommended ROE took into consideration his analysis of the unlevered ROEs of the proxy group, something that Morin ignored altogether.

As explained above, it is critically important to consider the authorized ROE in tandem with the capital structure to maintain DEP's credit rating and to determine an optimal allowed ROE. Treating the capital structure as fixed at 53% equity while maintaining an A2 credit rating would unnecessarily impose additional costs on ratepayers without any corresponding benefits.

c. Morin's sole example of an instance where a reduced ROE harmed customers actually demonstrates that reduced ROEs provide enormous customer benefits.

Witness Morin asserted that an allowed ROE of 6.0% would adversely impact DEP's creditworthiness, its financial integrity, and its customers. Tr. vol. 8, 218. He also testified that Ellis's recommendation would be contrary to customers' interests. *Id*. at 204. But none of those claims were substantiated.

When asked how a lower ROE would cause adverse consequences for DEP's customers, witness Morin gave the example of Arizona Public Service (APS) and the one-notch bond rating downgrade that followed the Arizona Commission's decision to set an allowed ROE of 8.7%, which is below the previously allowed ROE of 10.0%. Tr. vol. 8, 305-12; NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 12 (Official Ex. vol. 9 at 190-92). But in response to further questioning, witness Morin could not identify <u>any</u> actual cost increases to customers of APS that had yet occurred. He did not identify with specificity how any increases in borrowing costs for any new debt issuance (or even refinancing of all outstanding debt) could possibly overcome the tangible savings for customers of approximately $76 million per year that result from the reduced authorized ROE. Tr. vol. 8, 309; NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 13 (Official Ex. vol. 9 at 209).

For example, even if APS had to refinance all its outstanding debt of $3.9 billion at a 0.1% higher incremental cost, which would result in an increase in the cost of debt for APS's customers of $3.9 million. But it is important to remember that any marginal increase in borrowing costs would only apply to new issuances of debt, not to preexisting debt. Witness Morin disputed that a one notch downgrade from A- to BBB+ would result in an incremental increase of approximately 0.1% in borrowing costs. Tr. vol. 8, 310-11. He initially suggested that it would cost 0.5% more, then later 0.25% or 0.2% more to APS's cost of debt. *Id*. But witness Morin provided no evidence to support his claim that such a small downgrade would result in that level of incremental change in borrowing costs.

More importantly, Morin's testimony on the cost of such a downgrade was flatly contradicted by DEP cost of debt witness Karl Newlin, who testified that such "a single notch downgrade for DEP would likely constitute an incremental borrowing cost of 5 to 10 basis points," or 0.05% to 0.1%. Tr. vol. 22, 186. If a single-notch downgrade occurred following a Commission decision to set the allowed ROE lower than DEP is seeking—which as witness Ellis demonstrated, is not a foregone conclusion, depending on the corresponding capital structure—the Commission can reasonably anticipate an increase in borrowing costs of 0.05% to 0.1%. Witness Morin suggested that DEP would be raising $2.5 billion in debt, which would translate into an additional cost of debt of $1.25 to $2.5 million for DEP's customers. If that is the worst outcome that can be feared from setting a more reasonable return on equity—which could save Duke's customers hundreds of millions of dollars per year—then witness Morin helped to prove that a lower ROE is an enormous benefit to DEP's customers.

Even more confounding was Morin's assertion that the Arizona Commission's decision to set the allowed ROE for APS at 8.7% would lead to an <u>increase</u> in the cost of equity. Tr. vol. 8, 309-12; NCJC, *et al*. Cross Examination Morin Direct Rebuttal Ex. 12 (Official Ex. vol. 9 at 190-92) ("[t]he bottom line is that capital suppliers, both debt and equity, will require a higher rate of return in the presence of low regulatory quality… . Low regulatory quality leads to an increase in the cost of capital and, by extension, the rates charged to consumers"). But witness Morin otherwise insists that the cost of equity is the return on equity. Tr. vol. 8, 206. And he does not explain how setting an allowed ROE lower than the utility originally sought could possibly lead to an <u>increase</u> in the cost of equity for APS's customers. It is the authorized ROE that customers pay in their rates, not the cost of capital expected by investors. It is understandable that a reduced ROE could lead to an adjustment in stock price, but witness Morin provided no evidence that setting a lower allowed ROE leads to an increase in the utility's cost of equity capital or increased costs to ratepayers. As long as the Commission's decision is within constitutional bounds, the authorized ROE decision is a zero-sum game between shareholders and ratepayers. Tr. vol. 21, 1072.

What is most striking about the APS case is that it was DEP's only concrete example of how a lower ROE harms ratepayers. But the Arizona Commission's decision will conservatively save APS customers over $70 million per year, even accounting for marginally higher borrowing costs from the one-notch downgrade. Though witness Morin describes that result as a "disaster" that will damage ratepayers, the facts show the opposite is true. Tr. vol. 8, 312-13. It may be unfortunate for existing stockholders, who faced a one-time price adjustment in share price, but it provided significant rate relief to APS's customers. And there is no evidence that APS will be unable to continue to attract equity capital with an allowed ROE of 8.7% or otherwise be unable to maintain its financial viability. Witness Morin's alarmist rhetoric about the APS decision lacks any substance.

E. Conclusion.

As noted at the outset, DEP has not met its burden to establish that the authorized rate of return on equity should be set at either 10.2% or 10.4%. Such an excessive return would represent an unjustifiable transfer of wealth from ratepayers to the Company's shareholders and is out of step with the returns investors expect from investments of comparable risks. Witness Morin's testimony was inconsistent with his published work, subject to unexplained changes from his direct to supplemental testimony, and relied on inputs that biased his results upwards. Witness Ellis's approach was more thorough, transparent, internally consistent, and supported by best practices in finance. If the Commission's ultimate decision on the allowed ROE for DEP is based on the recommendations of witness Ellis, DEP's ratepayers would save hundreds of millions of dollars per year while still allowing DEP access to the capital markets and the ability to maintain its current credit rating.

V. The Commission Should Reject the PIMs Settlement and DEP's PBR Application and Convene a Policy Goals Docket.

In addition to determining whether a PBR application "would result in just and reasonable rates, is in the public interest, and is consistent with the criteria established in [G.S. 62-133.16] and rules adopted thereunder," N.C.G.S. § 62-133.16(d)(1), the Commission can consider whether that application, among other things, advances certain policy goals. *Id.* § 62-133.16(d)(2). These policy goals include but are not limited to (1) peak load reduction or efficient use of the system; (2) utility-scale renewable energy and storage; (3) DER; (4) reduction of low-income energy burdens; (5) energy efficiency; and (6) carbon reduction. *See id.*

The Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics, and Decoupling Mechanism (PIMs Settlement) between DEP, the Carolina Industrial Group for Fair Utility Rates II (CIGFUR), and

Public Staff – North Carolina Utilities Commission (Public Staff or PS) is a non-unanimous stipulation resolving certain aspects of DEP's PBR application as between the stipulating parties. Accordingly, the following applies:

> [It] should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding.[4]

State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998).

A. The PIMs Settlement Would Not Result in Just and Reasonable Rates and Is Not in the Public Interest.

The PIMs Settlement and the PBR application more generally would not result in just and reasonable rates, are not in the public interest, and should therefore be rejected.

When determining whether a PBR application would result in just and reasonable rates and advance the public interest, it is important to consider the overall aims and objectives of PBR under HB 951. At bottom, PBR is designed to better align utility profitmaking incentives with desired legislative, regulatory, and public policy outcomes, which DEP acknowledges include cost containment, affordability, and decarbonization. Tr. vol. 14, 74-75, 219. Ideally, MYRPs would

[4] *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice*, In the Matter of Application by Duke Energy Progress, LLC, Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Docket No. E-2, Sub 1219, at 28-29 (Apr. 16, 2021) (internal quotation marks omitted) (citing *State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc.*, 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998)).

incentivize cost containment through a strong revenue cap, tr. vol. 22, 1109, and advance other preferred outcomes by reducing regulatory lag, which would in turn potentially provide a utility with "better certainty on cost recovery for desirable actions like . . . affordability measures and decarbonization," *id.* at 1114. Decoupling would advance energy efficiency and in turn cost savings and decarbonization by severing the link between covered electricity sales and utility revenues. *See id.* at 1110, 1114.

On paper then, PIMs would accomplish PBR's overarching aims and objectives most directly by tying "a portion of utility's revenue to its performance…meeting" desired legislative, regulatory, and/or public policy outcomes. NCJC, *et al*. Cross Examination Bateman Stillman Direct and Settlement Ex. 1, at 23 (hereinafter NCJC *et al*. Bateman/Stillman Ex. 1) (Official Ex. vol. 16, part 2, 263). In the instant proceeding, designing PIMs that contain costs and promote affordability is critical given DEP's sizeable base case and MYRP revenue requirements, which are driven in large part by costly, misaligned, and largely unjustified distribution grid investments, and the excessively high 10.4% ROE that DEP seeks to apply to these investments. Tr. vol. 21, 841-42, 847-48, 925-1075*; see also* tr. vol. 17, 35-36 ("the benefits [of the MYRP distribution projects] were based upon the reduction of outage minutes"). However, overcoming the prevailing capital expenditure bias that exists under traditional cost of service ratemaking and meaningfully incentivizing cost containment and affordability instead would ultimately require DEP to tie a "significant portion of . . . [its] revenues" through its proposed PIMs in order to achieve these cost containment and affordability objectives. NCJC *et al*. Bateman/Stillman Ex. 1, at 23.

In relevant part, N.C.G.S. § 62-133.16(c)(4) provides "that the total of all potential and actual PIM incentives or penalties . . . [cannot] exceed one percent (1%) of the electric public utility's total annual revenue requirement that is used to fix rates during the first year of the MYRP pursuant to G.S. 62-133."[5] DEP witness Melissa Abernathy testified that for purposes of this PIM incentive cap, 1% of the proposed revenue requirement is $40.68 million. Tr. vol. 13, 116. Therefore, given the significant projected rate increases if DEP's PBR application were approved, which would hike residential customer bills by an average of 18.7% over three years,[6] it is even more important that DEP's proposed PIM rewards and penalties maximize the PIM incentive cap to the greatest extent possible.

Unfortunately, the PIMs Settlement fails to maximize the PIM incentive cap, which on its own forecloses any possibility that the proposed PIMs could meaningfully advance cost containment, affordability, and decarbonization. The PIMs Settlement has a maximum incentive upside and downside potential of +/- $10 million. Tr. vol. 14, 134. Based off DEP's own analysis, there is approximately $30.68 million worth of additional, potential PIM rewards or penalties that could have been directed to incentivize cost containment, affordability, and decarbonization and which the PIMs Settlement failed to deploy.

[5] This cap "exclud[es] any revenue requirement for the capital spending projects to be placed in service during the first rate year, where the PIM is approved" and any "incentives related to demand-side management and energy efficiency measures pursuant to G.S. 62-133.9(f)." N.C.G.S. § 62-133.16(c)(4).

[6] *Application to Adjust Retail Base Rates and for Performance-Based Regulation, and Request for an Accounting Order*, at 26. *See* tr. vol. 14, 229.

DEP contends that the PIMs settlement "represents a just and reasonable resolution of the Company's first PIM proposals and tracking metrics" as it "advances important policy goals and sets target achievement and incentive levels that will encourage utility performance and accountability." *Id.* at 142. More specifically, DEP witnesses represented on the stand that the PIMs Settlement's limited, aggregate PIM penalties and rewards reflect the Company's desire "to step into [PBR] to learn, to gain experience, to understand how the process works." Tr. vol. 15, 67.

However, it is unclear how the Company squares this ostensibly cautious approach with the nearly $3.871 billion it will seek to recover from its customers for capital expenditures on the distribution gird over the next three years, especially given the significant concerns the Public Staff and other interveners have raised regarding DEP's ability to execute many of its proposed MYRP and non-MYRP projects. *See, e.g.*, tr. vol. 16, 459-60, 465-81; tr. vol. 17, 39-40. This explanation is also undermined by the Company's firm opposition in the PBR rulemaking proceeding to the convening of a PIMs policy goals docket prior to the filing of a PBR application.[7] Indeed, a policy goals docket would have provided precisely the measured and deliberate approach the Company now asserts is its intent. Given the significant projected rate increases and likely bill impacts if DEP's PBR application were approved, DEP's failure to maximize the PIM incentive cap and adequately justify this decision arguably amounts to an abdication of its

[7] *Order Adopting Commission Rule R1-17B*, In the Matter of Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, Docket No. E-100, Sub 178, at 7-8 (Feb. 10, 2022) (hereinafter *PBR Rulemaking Order*).

responsibility to assure that no customer or group of customers is unreasonably harmed.

Putting to the side DEP's failure to maximize the PIM incentive cap, the PIMs Settlement portfolio fails on the merits to meaningfully advance cost containment, affordability, and decarbonization. The proposed PIMs also fail to adhere to the PIM principles developed in the North Carolina Energy Regulatory Process (NERP),[8] which DEP agrees provide valuable guidance on PIMs design best practices. *See* tr. vol. 15, 25-26. As a threshold issue, a utility must first determine "whether a reward or penalty is necessary. Among other things, this inquiry rests on existing utility incentives (and disincentives), the existing regulatory environment, and the level of utility control over the desired outcome." NCJC, *et al*. Bateman/Stillman Ex. 1, at 23-24.

Should a utility determine that rewards or penalties are necessary, it must then design each PIM with the following considerations in mind:

- PIMs should advance public policy goals, effectively drive new areas of utility performance, and incentivize nontraditional methods of operating.
- PIMs should be clearly defined, measurable, preferably using available data, and easily verified.
- PIMs should collectively comprise a financially meaningful portion of the utility's earning opportunities.

[8] NERP was a stakeholder process North Carolina Governor Roy Cooper convened to identify utility regulatory forms that would help support the clean energy transition. Tr. vol. 14, 74-75.

- No adopted PIM should duplicate a reward or penalty created by another PIM or other legal or regulatory mechanism.
- PIMs should reward outcomes, not inputs. In other words, the NCUC should avoid using expenditures as PIM metrics unless the desired outcome is increased spending.
- PIMs with metrics not controllable or minimally controllable by the utility should be upside only.

Id. at 24. "The utility should [also] track the overall performance for each adopted PIM or tracked metric, and, where possible, separately track the utility's performance in low-income counties, specifically Tier 1 and 2 counties." *Id.* at 9. "Once a PIM is established, it should be revisited on a regular basis to evaluate whether the selected metric, target, and incentive level are appropriate for achieving the outcome in question. If not, those parameters should be adjusted to improve performance." *Id.* at 24-25.

1. *Time-Differentiated, Dynamic Rate Enrollment PIM.*

DEP has not adequately demonstrated that the time-differentiated dynamic rate enrollment PIM (Rate Enrollment PIM) would reduce peak loads, let alone promote carbon emission reductions. With respect to the NERP PIM principles, the Rate Enrollment PIM is not clearly defined, and DEP has failed to meaningfully consider whether a reward or penalty is necessary given the existing regulatory environment and level of utility control over certain incremental customer enrollments.

Under the upside only Rate Enrollment PIM, DEP would receive a $5 reward for each additional customer that enrolled in a qualifying, time-differentiated, dynamic rate. Tr. vol. 14, 135. At present, those rate schedules are R TOU, R TOU D, and R TOU CPP. *See* tr. vol. 15, 23. Compensation would be capped at 250,000 customers, which would result in a maximum PIM reward of $1,250,000 each rate year. PBR Policy Panel Settlement Ex. 1, at 1 (Official Ex. vol. 16, part 1, 389).

DEP has not adequately demonstrated that the Rate Enrollment PIM would "encourage[] peak load reduction or efficient use of the system" or encourage reductions in carbon emissions. N.C.G.S. § 62-133.16(d)(2). At bottom, the Rate Enrollment PIM seeks to incentivize incremental customer enrollments in qualifying rate schedules, rather than winter peak load reductions. While DEP estimates that "the average expected [w]inter peak reduction per enrolled customer . . . [would be] approximately ~0.21-0.31 kW," which it projects would deliver a current utility system benefit of approximately $70 to $80 per kW, PBR Policy Panel Ex. 1, at 2, Official Ex. vol. 16, part 1, 52, "it is very likely that estimated savings will not exactly match real savings," tr. vol. 21, 1130. Savings will depend at least in part on whether and to what extent a given customer responds to the rate schedule price signals. Tr. vol. 15, 38-39.

And even if DEP's estimated savings matched real savings, the aggregate level of savings (and system benefits) are unknowns as DEP, among other things, has not provided an estimate of how many additional customers it anticipates will enroll in the qualifying rate schedules. *Id.* at 39. With respect to carbon reductions, DEP has provided no evidence quantifying the degree to which incremental customer enrollments will reduce carbon emissions. *Id.* at 40.

In addition, the Rate Enrollment PIM is not clearly defined. As NCJC, *et al*. witness Posner notes, "DEP is asking the Commission to approve the PIM prior to finalizing two key variables in the metric's calculation: the winter peak-load reduction per enrolled customer (kW/customer) and the system benefit of this reduction ($/kW)." Tr. vol. 21, 1130. There is even less precision with respect to any future rate schedules that the Commission might approve as there is absolutely no data, estimates or otherwise, quantifying per customer load reductions and benefits attributable to those reductions.

Moreover, it is not clear whether DEP has meaningfully considered whether some of the Rate Enrollment PIM rewards are necessary given the existing regulatory environment and concomitant lack of utility control. If the Rate Enrollment PIM were approved, DEP would receive a $5 per customer reward for each additional customer that enrolled in a qualifying rate. Meaning if only one customer enrolled, DEP would receive $5. Given the Commission's recent order approving Duke Energy's revised net metering tariffs, there will likely be at least some new residential customers who seek to participate in net metering for the first time, and, if the bridge rate cap were met,[9] would then be required to enroll in

[9] Pursuant to a stipulation the Commission approved in its order, new residential customers who apply to participate in net metering would have the option for a period of time of enrolling in a proposed bridge rate as opposed to a TOU CPP rate. *Order Approving Revised Net Metering Tariffs*, In the Matter of Investigation of Proposed Net Metering Policy Changes, Docket No. E-100, Sub 180, at 9-10 (Mar. 23, 2023).

the Residential Solar Choice tariff and take service under the TOU CPP rate.[10] Given the current design of the Rate Enrollment PIM, DEP would nevertheless receive a $5 incentive for each of these NEM customer enrollments in the TOU CPP rate, even though they would have only enrolled as a condition to participating in NEM. Relatedly, DEP has not indicated the current, “business-as-usual” baseline of enrollments in qualifying time differentiated rates each year. Establishing such a baseline and prohibiting DEP from receiving a reward for enrollments at or below it would at least prevent DEP from receiving unjustified compensation for business-as-usual enrollments in time-differentiated rates. Given the requirement that at least a subset of new residential net metering customers take service under a TOU CPP rate and given there is likely a “business-as-usual” baseline of customer enrollments in qualifying time-differentiated rates each year, it is unreasonable that there is no floor or dead band on Rate Enrollment PIM rewards that takes all of this into account.

2. *Reliability.*

DEP has not adequately demonstrated that a Reliability PIM would be necessary given the regulatory environment. In addition, while DEP commits to tracking the ten worst performing circuits, there are several challenges with this approach that would be better solved by DEP just tracking and reporting system reliability at the zip code or census tract level.

If a utility is operating under a MYRP with strong cost containment incentives, a downside only reliability PIM might be needed to prevent the utility

[10] *Id.* at 41-42.

from cost-cutting on system upkeep and maintenance to the detriment of system reliability. NCJC, *et al*. Bateman/Stillman Ex. 1, at 23. Here, however, the Reliability PIM may not be necessary for DEP "[g]iven the muted nature of the MYRP's cost-containment incentive." Tr. vol. 21, 1138. Under HB 951, rate increments during the MYRP period are tied to capital spending forecasts, which the utility may be incentivized to inflate. Tr. vol. 21, 1104. In contrast, MYRPs in other states are often tied to external indexes. NCJC, *et al*. Bateman/Stillman Ex. 1, at 4. Given DEP's recent trend of excessive spending on distribution-level capital projects that would at best only marginally improve an already reliable grid, it is highly unlikely that this PIM will meaningfully incentivize DEP's behavior or itself contribute to the goal of maintaining system reliability.

More importantly, the PIMs Settlement does not sufficiently prioritize monitoring potential reliability disparities in different communities. This is contrary to the NERP PIM principle recommending that utilities track their performance in low-income communities. While the stipulating parties have committed to tracking and reporting the ten worst performing circuits, they have yet to identify the proposed metric for defining "worst performing circuit." Tr. vol. 14, 141.

Furthermore, even though the stipulating parties commit to jointly adopting a proposed metric and filing that metric with the Commission sixty days after a Commission order, limiting tracking and reporting to the ten worst performing circuits, however that phrase is defined, would be insufficient. Indeed, DEP noted that the fifty worst performing circuits for purposes of SAIDI and SAIFI "change from year to year irrespective of the amount of work performed." Tr. vol. 23, 192.

Moreover, depending on the number of circuits tracked, it is unclear whether this approach would provide DEP, the Commission, and stakeholders the necessary visibility into any potential service reliability issues experienced in low-income communities, communities of color, or EJ communities.

Given these challenges, at a minimum, DEP should track and report SAIDI and SAIFI at the zip code or census tract level and report those results. In addition, DEP should track and report at the zip code or census tract level the following: (1) "Distribution line miles"; (2) "Average age of distribution equipment by kilovolt rating"; (3) "Number of vegetation projects"; and (4) "Number of distribution or transmission hardening projects." Tr. vol. 21, 893. This tracking and reporting would help the Company to identify and address any potential reliability disparities that exist between EJ communities and non-EJ communities while avoiding the turnover issue DEP has identified with tracking and reporting the worst performing circuits.

3. *Renewable Integration PIM.*

a. Metrics A, B, and C.

DEP has not sufficiently demonstrated that a reward for Metric A would be necessary. The upside only Metric A would reward DEP for exceeding certain net metering (NEM) interconnection thresholds relative to a three-year rolling average. Tr. vol. 14, 138. Net metering undoubtedly provides real value to DEP, net metering customers, and non-participants. Notwithstanding significant supply chain and inflationary headwinds, "DEP saw a 15% increase in rooftop solar connection requests in 2020, a 32% increase in 2021, and a 31% increase in

2022," which is a testament to its benefits. Tr. vol. 21, 1140. Also, the Inflation Reduction Act (IRA) will unlock additional tax credits, rebates, and savings for customers wishing to install behind the meter solar. *Id.* at 1141-42. Given strong previous growth in net metered interconnections and the significant number of IRA incentives for prospective net metering customers, it is unclear what problem Metric A is seeking to solve or what actions DEP could take to increase NEM enrollments.

While there is potentially a problem to be solved with respect to Metric B, it is unclear which specific iteration of that problem Metric B seeks to solve, and whether it optimally seeks to incentivize or reward the right outcome. As currently envisioned, Metric B seeks to incentivize large customer renewable energy program subscriptions. Tr vol. 14, 138. Ideally, the PIM incentives would "allow (or inspire) the utility to optimize a suite of possible interventions to support achieving an outcome at least cost," tr. vol. 21, 1143, but it is unclear what that outcome is given the murkiness of DEP's justification for this PIM, *id.* at 1144. If the outcome is additional renewables for large customers, Metric B, by definition, will not achieve that outcome (and will not generate regulatory surplus[11]) as "the utility-scale resources that will be used . . . will be procured by DEP as part of annual procurement." *Id.* If, on the other hand, the presence of this incentive would steer DEP to alter its pending customer programs to ensure that they resulted in regulatory surplus (in other words, additional solar installations beyond what DEP

[11] A regulatory surplus exists when customer purchases of clean energy (or its functional equivalent) lead to clean energy procurement or deployment over and above existing legal or regulatory requirements. *See Regulatory Surplus*, EPA, https://www.epa.gov/green-power-markets/regulatory-surplus (last visited Jun. 7, 2023).

plans to achieve through Carbon Plan required procurements), then there might be merit to this PIM proposal. But until DEP indicates that it is incorporating stakeholder feedback and redesigning its customer programs to ensure that they result in additional solar procurements, it remains unclear what policy goals Metric B advances.

Lastly, while the revised Metric C is a largely welcome addition, it should be revised to incorporate any Commission-approved, upward adjustments to the utility-scale solar interconnection assumptions that were established in the first Carbon Plan proceeding. *See generally* tr. vol. 14, 139 (providing general information about the new utility-scale interconnections Metric C). As revised, Metric C incentivizes utility-scale solar interconnections over and above existing Carbon Plan interconnection assumptions. *Id.* These interconnection assumptions were supported by modeling Duke Energy conducted in that proceeding. Tr. vol. 18, 407-08. It is entirely possible that the Commission might require upwards adjustments to these assumptions in the upcoming CPIRP proceeding (or other proceedings) given the facts on the ground and/or compelling new modeling results from Duke Energy, the Public Staff, or other interveners. Consistent with the NERP PIM principles, adjusting Metric C to reflect these new, approved interconnection limits would ensure Metric C's benchmarks are adjusted as appropriate to improve performance.

Given these deficiencies in the PIMs Settlement and the costly and largely unnecessary MYRP grid investments, the Commission should reject the PBR application.

B. The Commission Should Adopt Witness Posner's PIM Proposals.

If the Commission should choose to adopt DEP's PBR application with modifications or require DEP to refile its PBR application, the Commission should also require DEP to modify its updated PBR application to include the PIM proposals set forth in NCJC, *et al*. witness Posner's pre-filed direct testimony and that were not otherwise resolved pursuant to the Affordability Settlement. Witness Posner's PIM proposals maximize the PIM incentive cap and tie a "significant portion of . . . [DEP's] revenues" to the achievement of cost containment, affordability, and decarbonization, *see* NCJC, *et al*. Bateman/Stillman Ex. 1, at 23, with the IRA Savings Uptake PIM alone providing penalties in the amount of "$7,085,334 in rate year 1, $19,617,148 in rate year 2, and $30,248,435 in rate year 3," tr. vol. 21, 1169.[12]

Pursuant to N.C.G.S. § 62-133.16(d)(3), the Commission must "issue an order approving, modifying, or rejecting the electric public utility's PBR application." In addition, "[i]f the Commission rejects the PBR application, it shall provide an explanation of the deficiency and an opportunity for the electric public utility to refile, or for the electric public utility and the stakeholders to collaborate to cure the identified deficiency and refile." *Id.*

Witness Posner's symmetrical Fuel Cost PIM would advance the HB 951 policy goals of cost savings, operational efficiency, low-income energy burden reductions, and carbon emission reductions. Tr. vol. 21, 1155. As envisioned, the Fuel Cost PIM seeks to incentivize DEP to reduce its fuel costs, a goal shared by

[12] These penalties would have to be adjusted for credit transfer costs. Tr. vol. 21, 1169.

several other interveners. Tr. vol. 21, 670-80*; see also* tr. vol. 18, 56-58 (proposing on behalf of the Attorney General's Office a fuel cost ROE differentiation metric that would reduce the ROE for fossil fueled resources). Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55, an electric public utility can recover all its prudently and reasonably incurred fuel and fuel related costs in annual fuel rider proceedings. These costs, which can amount to 16-21% of the average residential bill, are passed through and recovered in their entirety from customers. Tr. vol. 21, 1150. As a result, the utility bears none of the ultimate risk if costs increase more than expected. *Id.* at 1149-50.

Witness Posner's proposed Fuel Cost PIM "would allow the utility to capture a share of the benefits if fuel costs turn out to be lower than expected and require it to bear the same share of the cost if they turn out to be higher than expected," with the annual reward or penalty capped at $20 million. *Id.* at 1151. By requiring DEP to bear some fuel cost risk, the PIM will incentive DEP to both operate its fossil fuel assets even more efficiently and operate more fuel free renewables, which will reduce costs and carbon emissions. While Posner stopped short of recommending a specific sharing percentage for the Fuel Cost PIM, he did model the impacts of a 5% sharing factor under two scenarios. *Id.* at 1152. During a 50% fuel cost spike relative to DEP's budgeted fuel cost, the Fuel Cost PIM would minimize the spike's reduction of DEP's earnings and "mitigat[e] 10% of the fuel cost impact that would otherwise have been fully passed through to ratepayers." *Id.* at 1157. On the flipside, the PIM would increase DEP's net earnings by up to

1.1% if, as a result of re-optimized economic dispatch and additional solar, DEP reduced its fuel costs by 25%. *Id.* at 1158.

Lasty, this proposal is permissible under N.C.G.S. § 62-133.2 and Chapter 62 more generally. N.C.G.S. § 62-133.2(f) provides the following:

> Nothing in this section shall relieve the Commission from its duty to consider the reasonableness of the cost of fuel and fuel-related costs in a general rate case and to set rates reflecting reasonable cost of fuel and fuel-related costs pursuant to G.S. 62-133. Nothing in this section shall invalidate or preempt any condition adopted by the Commission and accepted by the utility in any proceeding that would limit the recovery of costs by any electric public utility under this section.

The Commission has the obligation to consider the reasonableness of the cost of fuel and fuel-related costs in a general rate case. The Commission may also adopt conditions that limit the recovery of fuel and fuel-related costs. In addition, HB 951 would not otherwise preclude a fuel cost PIM. Fuel cost reduction is a policy goal related to the “expected or anticipated achievement of operational efficiency [and] cost savings . . . greater than” existing state or federal requirements. N.C.G.S. § 62-133.16(a)(8). While fuel cost reduction has downstream environmental impacts, it is not a prohibited environmental standard for purposes of § 62-133.16(a)(8). Any reading to the contrary would unreasonably expand this prohibition’s reach.

Despite the tangible benefits the Fuel Cost PIM would deliver, DEP, in an inversion of the burden of proof, contends that NCJC, *et al*. has failed to adequately support its PIM proposal. However, NCJC, *et al*. provided extensive modeling of the impacts of the proposed fuel cost PIM and provided DEP with supporting workpapers. Secondly, DEP argues that the Fuel Cost PIM would be unworkable as DEP does not have sufficient control over certain drivers of its fuel costs, tr. vol. 23, 205-06, but at the same time praises its fuel cost containment measures, *id.* at 204-05. While NCJC, *et al*. acknowledges that DEP, on its own, has no control over fuel commodity prices, and, absent any financial support it might provide for weatherization, has no control over weather impacts on customer load, there are undoubtedly several other drivers over which DEP has at least some control. Otherwise, DEP's fuel cost containment measures, which it takes great pride in, would constitute a futile, potentially costly misuse of its time and resources.

DEP also notes that a fuel cost PIM would be unnecessary given that the Commission can always disallow imprudent fuel costs. However, a fuel cost PIM would provide customers the guarantee of fuel rate relief with respect to unbudgeted fuel costs, all without the need for the Public Staff and other interveners to investigate and recommend disallowance in potentially protracted litigation.

Lastly, DEP submits a fuel cost PIM is unnecessary because its rates, unlike rates in Hawaii, are low. However, for this argument to hold, Hawaii's high electric rates would have to be the dispositive factor justifying fuel cost sharing. Indeed, with respect to the other factors DEP cites in opposition to fuel cost sharing, Hawaii is more like DEP than DEP would probably want to admit. For example, DEP has presented no evidence that Hawaii's electric utilities have any more control over their fuel costs than DEP. In fact, given Hawaii's rather unique status as a geographically isolated state heavily dependent on imported oil for energy generation,[13] Hawaii arguably has even less control over its fuel costs than DEP. Moreover, DEP's bare assertion that a fuel cost PIM is unnecessary because of its low rates assumes that DEP rates will stay comparatively low for the long term. However, DEP's sister company Duke Energy Carolinas experienced a $998 million under-recovery in this year's fuel rider proceeding due in large part to increases in coal and natural gas commodity prices. Tr. vol. 23, 230-31. Furthermore, Duke Energy's planned natural gas buildout will only increase its customers' exposure to fuel price volatility.[14] Given this trajectory, it is unclear whether DEP's rates will always remain comparatively low.

NCJC, *et al.*'s downside only, IRA Savings Uptake PIM would advance the HB 951 policy goals of cost savings, operational efficiency, DER, and carbon emission reductions by penalizing DEP for failing to take full advantage of federal tax policies, including but not limited to investment tax credit (ITC) and production tax credit (PTC) adders under the IRA. Tr. vol. 21, 1168-69. These adders, along with other federal tax benefits, would further reduce the costs associated with the construction of or generation of power from qualifying solar or storage assets, provided DEP sited those assets in designated energy communities, used U.S.-sourced components, and/or satisfied other requirements. *Id.* at 1167. This in turn would make DER and renewables more generally more cost competitive relative to other power supply alternatives and thereby reduce overall customer costs and

[13] *Hawaii*, *State Profile and Energy Estimates*, U.S. ENERGY INFORMATION ADMINISTRATION, https://www.eia.gov/state/analysis.php?sid=HI (last updated Mar. 16, 2023) (providing that Hawaii relied on oil for 62% of its electricity generation needs in 2022).

[14] *Order Adopting Initial Carbon Plan*, In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179, at 79 (Dec. 30, 2022).

carbon emissions. For example, "the value of the PTC can be increased 20% over the "bonus" level available when prevailing wage and apprenticeship requirements are satisfied." *Id.* The ITC's value "can increase 44 percentage points over the base level and 20 percentage points over the bonus level for large-scale projects (and 64 percentage points over the base and 40 percentage points over the bonus level for projects 5 MW or smaller in size that benefit low-income customers)." *Id.*

Specifically, the PIM would charge DEP for failing to leverage ITC and PTC adders consistent with the monetization rates that are in effect for the tax credit transfer market "when the credits are earned." *Id.* at 1168. The precise penalty would be equal to the ratepayer impact associated with DEP's failure to leverage these adders "minus any cost savings that can be convincingly attributed to" DEP's decision not to pursue those adders. *Id.* As noted in witness Posner's testimony, "the tax credit transferability provisions of the…[IRA] are already being incorporated into financial sector term sheets and contracts with pricing between 90 and 92 cents on the tax credit dollar." *Id.* at 1102. While DEP has proposed creating a regulatory asset for certain ITC and PTC adders, this approach would reduce their value by charging customers a rate of return. *Id.* at 1167-68.

DEP avers that the IRA Savings Uptake PIM should be rejected given the prospect of disallowance, its regulatory asset proposal, the uncertainty surrounding these adders, and NCJC, *et al.*'s alleged failure to provide sufficient information supporting the PIM or explaining how it was designed. The Commission should reject these arguments. First, for reasons provided earlier, the potential for disallowance is not an effective substitute or replacement for a PIM.

Second, DEP's preferred regulatory asset approach would require customers to pay carrying costs for unmonetized adders. *See id.* at 1168. Third, IRA tax credits transfers are already being valued between 90 to 92 cents on the tax credit dollar. *Id.* at 1116. Lastly, NCJC, *et al*. has provided ample information supporting its PIM. To the extent NCJC, *et al*. has not provided certain information, DEP, which is the utility, has equal or greater access to that information.

Lastly, NCJC, *et al*.'s NWA Projects Shared Savings Mechanism (NWA PIM) would advance the HB 951 policy goals of operational efficiency, cost savings, reliability, grid resiliency, affordability, and decarbonization, among other things. *Id.* at 1163. This PIM would help facilitate the identification and adoption of NWA solutions such as DERs that would address reliability, resiliency, and other grid needs and reduce carbon emissions, while obviating the need for costlier, traditional grid investments.

Under the upside only NWA PIM, DEP would share some of the total savings attributable to adopting NWA solutions with its customers. In addition, the Commission or an independent party "would approve the savings in total ratepayer costs attributable to each NWA solution deployed in a rate year relative to the traditional T&D investment it is delaying or replacing." *Id.* at 1162. Assuming a 20% sharing factor and assuming DEP's selected NWA solutions reduced grid investment costs by 50%, witness Posner's modelling reveals that the NWA PIM would provide DEP with a $8.6 million incentive and deliver annual revenue requirement savings of $43 million. *Id.* at 1163. These savings would flow back to ratepayers when rates are reset following the end of the MYRP period. *Id.* at 1164-65.

DEP cites its NWA screening process and one single NWA project as evidence that the NWA PIM is unnecessary, tr. vol. 23, 209. However, DEP's NWA screening process only allows batteries to be selected as an alternative to traditional grid investments. Tr. vol. 21, 850. In addition, as discussed previously, the Company's cost-benefit framework primarily focuses on outage reduction benefits and fails to consider other benefits NWA solutions can deliver. *Id.* at 848. Lastly, given the paucity of NWA solutions DEP has implemented or proposed relative to its grid modernization needs, it is not unreasonable to infer that DEP might identify and adopt more NWA solutions if it had additional incentive(s). Indeed, DEP seems to concede this point. Tr. vol. 23, 209 (noting that the "Company is not opposed to the concept of a[n] NWA metric that is upside only").

In sum, the Commission should approve witness Posner's PIM proposals as they maximize the PIM incentive cap and advance cost containment, affordability, and decarbonization.

C. The Commission Should Convene a Policy Goals Docket.

Many of the issues with DEP's PBR application stem from a lack of focus on relevant outcomes and policy goals. There is both a lack of sufficient evidence with respect to whether DEP's PIMs would meaningfully facilitate achievement of the identified outcomes and policy goals and whether certain outcomes even need to be incentivized. These issues could be addressed through the convening of a policy goals docket that builds upon the recommendations of interveners in the PBR rulemaking proceeding and draws from examples from other jurisdictions.

Although the Commission initially declined to adopt a requirement for a policy goals docket in Commission Rule 1-17B, it noted in the *PBR Rulemaking Order* that "the Commission may choose to initiate dockets to set policy goals for PBRs if it determines in the future that such dockets would be useful."[15] This current proceeding demonstrates the usefulness of such dockets going forward. Having a policy goals docket would allow for stakeholder development of consensus policy goals that the Commission could consider in advance of a future (or re-filed) PBR application, along with supporting the assessment and refinement of consensus policy goals, performance metrics, and PBR outcomes on an ongoing basis. By bringing together the shared expertise and perspectives of utilities, regulators, and other stakeholders in a neutral, formal setting, the risk that any one approved policy goal was not sufficiently needed or supported by the evidence would be greatly diminished. A policy docket would also provide the Commission with the ability to clarify before a PBR application is filed which policy goals it seeks to advance, allowing parties to focus on PIMs that advance those goals.

As for the specifics, Rule R1-17B(g) provides that "[t]he Commission will establish the procedure for the annual review and issue an order setting forth the procedure based on requirements of this Rule." Accordingly, consistent with this provision, the Commission could open a permanent policy goals docket and issue

[15] *PBR Rulemaking Order* at 14.

an order consolidating that docket with the Rule R-17B(g) annual review. However, the content and duration of the initial policy goal stakeholder process would likely hinge on the Commission's order in this proceeding. If the Commission were to require DEP to re-file its PBR application, the Commission could establish a streamlined stakeholder process for the purpose of curing the deficiencies the Commission identified in DEP's PBR application and facilitating the re-filing of a cured PBR application, consistent with N.C.G.S. § 62-133.16(d)(3).

If the Commission were to either accept or reject DEP's PBR application outright, the Commission's order consolidating the two proceedings could provide for a longer, initial stakeholder process, the content and duration of which could also govern the development of new policy goals in future MYRP periods and PBR applications unless the Commission ruled otherwise. If the Commission were to require DEP to refile its PBR application, this process could also inform the structure of any stakeholder processes following the Commission's approval of DEP's cured application. For example, this full stakeholder process could entail Commission organized workshops to foster shared learnings and help facilitate consensus policy goals that would inform any PBR mechanisms included in future PBR applications. At a high level, this stakeholder process could mirror the process in Minnesota. There, the Minnesota Public Utilities Commission established a "'goals-outcomes-metrics process' as an effective method to gather stakeholder input and develop performance metrics." NCJC, *et al*. Bateman/Stillman Ex. 1, at 51.

Following the Commission's adoption of policy goals and approval of a PBR application that incorporated those goals, the Commission could then track and assess utility achievement of those goals on an ongoing basis through the mechanisms provided in Rule R1-17B(g) and (f) and work with the utility and other stakeholders to translate these reports and outputs into more user-friendly scorecards for the general public to review. In addition, the Commission could conduct or require additional reporting and tracking of policy goal performance. Stakeholders could file comments or letters in the consolidated annual review docket that assessed utility achievement of approved policy goals and recommended potential modifications to those goals. In the Commission's discretion, expert witness hearings could be scheduled to resolve issues of fact stemming from the assessment and recommended modification of policy goals. Depending on utility performance, facts on the ground, and any Commission orders, directives, or rulings regarding the same, stakeholder collaboration to develop new policy goals through workshops (and any other means the Commission identified) could proceed concurrent to the assessment and refinement of existing policy goals already occurring in the consolidated annual review.

RELIEF REQUESTED

For the foregoing reasons, NCJC, *et al*. respectfully urges the Commission to do the following:

1. Reject DEP's PBR application, or in the alternative, modify DEP's PBR application to incorporate NCJC, *et al*.'s recommendations and the alternative

PIM proposals NCJC, *et al*. witnesses David Posner, David Hill, and Jake Duncan proposed.

2. Reject DEP witness Morin's recommended rate of return on equity (ROE) and adopt NCJC, *et al*.'s witness Ellis's recommended allowed ROE instead.

3. Initiate a working group to redesign the Company's cost-benefit analysis for grid modernization and DERs.

4. Require the Company to conduct two NWA pilot projects, with one focusing on an environmental justice community.

5. Initiate an investigation into distribution system planning to establish stakeholder supported (i) grid modernization objectives, (ii) reporting and data sharing requirements for regulated electric utilities, (iii) NWA methodology and proposal requirements, (iv) community engagement plan, and (v) exploration of the EJ aspects of grid modernization.

6. Require DEP to report reliability data at the census tract and nine-digit zip code level-comprised of aggregated and anonymized customer premise level data-in order to investigate potential disparities in reliability services.

7. Require the Company to use its existing grid hosting capacity stakeholder process to evaluate the fourteen decision points for an effective hosting capacity analysis as described by Interstate Renewable Energy Council, collaborate with stakeholders to add sociodemographic, energy burden, and other environmental justice indicators on top of its planned grid hosting capacity map,

and include load hosting capacity in addition to generation hosting capacity in its grid hosting capacity.

8. Require the Company to update the proposed grid modernization plan investments to account for federal funds through the IRA and Infrastructure Investment and Jobs Act and require the Company to work with stakeholders to identify at least two target initiatives that address environmental justice through multiple DERs as non-wire solutions.

9. Convene a Policy Goals docket.

10. Approve the Affordability Settlement.

Respectfully submitted this 9th day of June, 2023.

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CERTIFICATE OF SERVICE

I certify that all parties of record have been served with the foregoing Post-Hearing Brief either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 9th day of June, 2023.

/s/ David Neal
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